Master's thesis

NTNU
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Department of Electric Power Engineering

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Analysing the Impact of 30 GW Offshore Wind Power in Norway using the Market Model FanSi

Master's thesis in Energy and Environmental Engineering
Supervisor: Magnus Korpås (NTNU)
Co-supervisor: Arild Helseth (SINTEF Energy Research)
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Abstract

In May 2022, the Norwegian government presented a plan to identify areas for 30 GW offshore wind power before 2040. The ambitious offshore wind initiative will significantly boost Norway's green energy production, resulting in a more robust energy balance and maintaining the country's position in the energy industry. However, the substantial increase in wind power production will have a significant impact on the Norwegian power system, which must be adequately prepared to accommodate this increased power production. A considerable challenge lies in managing the variable power generation caused by intermittent wind power. Flexible hydropower production is expected to play a key role in supporting the power system to cope with variability.

This master's thesis aims to investigate the impact of 30 GW offshore wind power on the Norwegian power system. Moreover, three different allocations of wind power capacity are analyzed to examine the impact of wind farm locations. The analysis utilizes a dataset representing a scenario for the Northern European power system in 2030. Five offshore wind scenarios in Norway are simulated, including one with zero production, another with 4.5 GW in the south, and three scenarios with 30 GW distributed across various regions of the country. The offshore wind production is directly transmitted to the nearest onshore area without any corresponding modifications made to the transmission system or power demand. Two sets of wind series are employed in the simulations to analyze and compare the recently generated wind series by SINTEF Energy Research with the original wind series initially included in the dataset.

The scenarios are simulated using the fundamental market model FanSi. FanSi is a long-term hydro thermal scheduling model developed at SINTEF Energy. The model utilizes a method called "Scenario Fan simulator", which solves sequences of stochastic optimization problems. FanSi computes individual water values for each reservoir instead of aggregated water values as in the widely used EMPS model. This allows for a more detailed representation of the hydropower system, which has shown to be beneficial regarding handling fluctuations in unregulated generation.

The findings of the study demonstrate the significant impact of substantial wind power production on the Norwegian power system. The results clearly indicate a noticeable decrease in area prices with increasing wind power production. The installation of 30 GW offshore wind capacity leads to a higher frequency of bottlenecks in the transmission system, highlighting the importance of aligning wind power developments with transmission capacity and power demand. The increased value factors for hydropower plants signify their ability to complement wind power generation and contribute to system balancing. Finally, the result reveals that social welfare from operating the power system is positively impacted by greater wind power production in the system, primarily driven by increased consumer surplus and surplus of the Transmission System Operator. Distributing the wind farms in a larger area leads to higher social welfare compared to concentrating them.

The new wind series results in increased wind power production compared to the wind series initially included in the dataset. This had a considerable impact on the results obtained from the simulations, highlighting the significance of accurate wind series in simulations involving large shares of wind power production. Furthermore, particular emphasis is placed on the end value setting in FanSi, obtained from water value calculation in the EMPS model. It was found that these water values were excessively high for large amounts of wind power production in the system. While a simplified solution was identified and implemented for the simulations conducted in this thesis, these findings emphasize the importance of further investigations into this issue.

Sammendrag

I mai 2022 la den norske regjeringen frem en plan om å identifisere områder for 30 GW havvind innen 2040. Det ambisiøse havvind-initiativet vil betydelig øke Norges grønne energiproduksjon, noe som vil resultere i en mer robust energibalanse og opprettholde landets posisjon innenfor energiindustrien. Den betydelige økningen i vindkraftproduksjonen vil imidlertid ha konsekvenser for det norske kraftsystemet, som må være tilstrekkelig forberedt på denne økte kraftproduksjonen. En utfordring ligger i å håndtere den variable kraftproduksjonen forårsaket av vindkraft. Fleksibel vannkraftproduksjon antas å spille en viktig rolle i å støtte kraftsystemet mot den variable vindkraftproduksjonen.

Denne masteroppgaven har som mål å undersøke virkningen av 30 GW havvind på det norske kraftsystemet. I tillegg vil betydningen av plasseringen av vindparkene analyseres ved å undersøke tre forskjellige fordelinger av havvindkapasiteten i Norge. Analysen benytter seg av et datasett som representerer et scenario for det nord-europeiske kraftsystemet i 2030. Fem havvind-scenarioer for Norge simuleres: ett med null produksjon, et med 4,5 GW i sør, og tre scenarioer med 30 GW fordelt over ulike regioner i landet. Havvindproduksjonen overføres direkte til det nærmeste området på land uten noen tilsvarende endringer i det norske strømnettet eller kraftbehovet. Simuleringene er utført ved bruk av to ulike sett med vindserier for å analysere og sammenligne de nylig genererte vindseriene fra SINTEF Energi med vindseriene som er inkludert i datasettet.

Scenarioene er simulert ved bruk av den fundamentale markedmodellen FanSi. FanSi er en langtids hydro-termisk planleggingsmodell utviklet ved SINTEF Energi. Modellen bruker en metode kalt "Scenario-vifte simulator" som løser sekvenser av stokastiske optimeringsproblemer. FanSi beregner individuelle vannverdier for hvert reservoar i stedet for aggregerte vannverdier slik som i den mye brukte EMPS-modellen. Dette muliggjør en mer detaljert representasjon av vannkraftsystemet, som har vist seg å være gunstig for å håndtere svingninger i uregulert kraftproduksjon.

Studiens funn viser hvordan en betydelig økning i vindkraftproduksjon vil påvirke det norske kraftsystemet. Økende vindkraftproduksjon vil gi en nedgang i kraftpriser. En øking på 30 GW havvindproduksjon i Norge fører til hyppigere flaskehalser i overføringsnettet, noe som understreker viktigheten av å samkjøre vindkraftutvikling med overføringskapasitet og kraftbehov. Fleksibilitetsfaktoren for vannkraft øker for mer vindkraft i systemet, noe som demonsterer vannkraftens evne til å komplimentere vindkraftproduksjonen. Det samfunnsøkonomiske overskuddet for driften av kraftsystemet påvirkes positivt av økt vindkraftproduksjon i systemet, primært drevet av økt forbrukeroverskudd og større overskudd for systemansvarlig i kraftsystemet (TSO). Å fordele vindparkene over et større område fører til høyere samfunnsøkonomisk overskudd sammenlignet med å konsentrere dem i et mindre område.

De nye vindseriene resulterer i økt vindkraftproduksjon sammenlignet med vindserien som opprinnelig var inkludert i datasettet. Dette påvirket resultatene i scenario-studiet, og understreker dermed viktigheten av nøyaktige vindserier i simuleringer som involverer store mengder vindkraftproduksjon. I arbeidet med simuleringene ble det rettet spesielt fokus på sluttverdiinnstillingen i FanSi, som blir beregnet ved hjelp av vannverdiberegning i EMPS. Det ble oppdaget at disse vannverdiene var overdrevent høye for store mengder vindkraftproduksjon i systemet. Selv om det ble identifisert og implementert en forenklet løsning for simuleringene som er gjennomført i dette prosjektet, fremhever dette funnet behovet for videre analyser knyttet til sluttverdiinnstillingen.

Preface

This master's thesis is written for the Department of Electric Energy at the Norwegian University of Science and Technology (NTNU) during the spring semester of 2023. The thesis is written in association with the subject "TET4900 Electric Power and Energy Systems, Master's Thesis". In preparation for this master's thesis, a preliminary project thesis was written during the fall semester of 2022. The analysis in this master's thesis is conducted in collaboration with SINTEF Energy Research, which has developed the market model used in the project.

I would like to thank my supervisor, Magnus Korpås, for his insight into power markets, which has been a great help when defining the case study and analyzing the results. I would also like to thank Arild Helseth for providing me with the help needed to simulate in FanSi, and for helpful responses to my questions and feedback on the project. Lastly, I would like to thank Stefan Jaehnert for the help with the Python script used to abstract results.

Trondheim, 9th of June, 2023

Kari Medhus

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1 Introduction

With the exception of a few improvements, section 1.2 is reused from the preliminary project thesis written during the fall of 2022 [1].

1.1 Motivation

Transitioning to renewable energy sources is a necessary step towards achieving net zero emissions by 2050. The green energy transition is becoming increasingly important due to the ongoing electrification and rising energy demand. Moreover, plans to reduce European reliance on Russian fossil fuels, due to the invasion of Ukraine, have further strengthened the motivation for speeding up the deployment of renewables. Across Europe, countries are developing strategies to boost the proportion of renewable energy generation and setting targets to incentivize the shift. The European Union (EU) initially aimed for a minimum of 32% renewable energy sources in the overall energy mix by 2030, but on 30th March 2023, the target was raised to at least 42.5% by 2030 [2]. In the northern part of Europe, one has recognized the significant potential for offshore wind power due to the expansive sea areas. Norway, which has historically relied on hydropower, has also embraced this idea and is now pursuing plans for a major offshore wind initiative.

Power situation in Norway

The Norwegian power system is known for a high share of renewable energy production, power surplus and flexible production capacity. Hydro production is responsible for about 89% of the Norwegian energy production in a normal year [3]. As of November 2022, the installed hydro capacity was 33.69 GW, giving a normal yearly production of 136,7 TWh [4]. The yearly hydro production is mainly affected by the water inflow, which varies from one year to another. There are also seasonal variations in inflow. The high inflow during late spring, summer and early autumn fills the reservoir. Furthermore, the reservoirs are emptied during winter due to low inflow and high energy demand. The ability to store water in a reservoir until needed makes hydropower a highly flexible energy source. The hydro producers can choose to generate power when demand, and consequently prices, are high. This quality is expected to be especially valuable in the future power system with an increasing share of unregulated energy production from solar and wind power. Besides hydro production, investments in wind power have increased significantly in Norway in recent years, and wind power currently accounts for 10% of the Norwegian production capacity [3]. This includes 65 wind farms, with an installed capacity of 5083 MW and a normal yearly production of about 16,9 TWh [5]. Apart from hydro and wind power generation, there is a small proportion of thermal and solar energy production. Nevertheless, solar production in Norway is on the rise. Overall, the energy mix in Norway makes it the country with the highest share of electricity produced from renewable sources in Europe [3].

As a consequence of the deregulation of electricity markets in the 1990s, Norway joined forces with Sweden, Denmark, and Finland to establish a joint Nordic power market [6]. Interconnections to continental Europe have facilitated the integration of the Nordic market with the European market. Norway has cross-border interconnections with Finland, Sweden, Denmark, Russia, Germany, the Netherlands and the United Kingdom. The Nord Link cable to Germany and the North Sea Link cable to the United Kingdom both become operational in 2021 [7]. The objective of the cross-border interconnections is to increase the security of supply, as well as value creation in the power section [8]. In addition, power trading enhances the efficient utilization of energy resources and leads to reduced overall costs compared to individual countries providing their own energy supplies [7]. The power always flows from low-price areas to high price-areas. As a hydro-based nation with flexible production capacity, Norway can benefit from the variations in electricity prices in the thermal-based power systems in continental Europe caused by costly regulation of thermal production. This is done by importing electricity during periods of low pricing, specifically at night, and subsequently exporting during times of high demand and elevated pricing during the day. In addition to its benefits in reducing prices and ensuring a secure supply of electricity during periods of high demand and low inflow in winter, trading also plays a crucial role in mitigating the impact of dry years [7].

Traditionally, the Norwegian power system has been characterized by a power surplus. Today, the power surplus in the Norwegian system is about 18 TWh in a normal year [9]. The power surplus varies, however, with weather conditions, especially inflow, and in dry year the surplus is significantly lower. Nevertheless, in the period from 1990-2021 Norway has been a net exporter in 22 of the 31 years, with an average power surplus of 6 TWh per year [8]. The power surplus has led to increasing export income and security of supply. There are however some concerns regarding the future power situation in Norway. A short-term market analysis for 2022-27, published by the Norwegian transmission system operator (TSO), Statnett, points out that Norway may have a net negative energy balance in 2027 [9]. This is due to significant expected growth in the demand for electricity, without a corresponding increase in power production. Statnett estimates that the demand for electricity in Norway will rise from 140 TWh in 2022, to 164 TWh in 2027. The electrification of the transport and petroleum industry, as well as the growth in industry and battery production, are among the main contributors to this growth. With an expected increase in power production by around 6 TWh, this will lead to a power deficit of around 2 TWh in 2027. The deficit is expected larger in Southern Norway with around a 7 TWh power deficit. As power production is highly affected by the weather, the power situation may be better or worse. Nonetheless, with a temporary cessation of onshore wind development, the anticipated increase in hydro production cannot fulfill the mounting demand. Statnett underscores that the deficit situation is likely to evolve in the long run because of the anticipated expansion of power production from offshore wind power, solar power, and possibly onshore wind power production. The Norwegian Water Resources and Energy Directorate (NVE) has published a Long term power-marked analysis for 2021-2040 [10] which also expects a worsened power balance in Norway towards 2030, as stated in Statnett's report. Nevertheless, NVE expects a smaller increase in power demand, resulting in a positive power balance for the whole period, with 7 TWh surplus in 2030 for a normal year. NVE further expects that production increases more than consumption after 2030, leading to a power surplus of 12 TWh in 2040. The surge in power production is attributed to the advancement of wind and solar production, in addition to the expansion of hydro production. The extent to which new power production is permitted is largely determined by the authorities due to concession processing. The pace at which costs decrease will also impact the development of offshore wind power. In 2022, NVE released an analysis of how the power balance in Norway impacts the extent to which the country is affected by high European prices [11]. The results indicate that strengthening the power balance in Norway could help reduce electricity prices in Norway during periods of high prices in Europe. Moreover, Norway will be less affected by large market fluctuations. This finding is consistent with the analysis by Statnett, which demonstrates that a larger power surplus leads to lower prices in Norway [9].

Offshore wind initiative in Norway

In May 2022, the Norwegian government presented a plan to identify areas for 30 GW offshore wind power before 2040 [12]. This initiative is in line with the government's ambitions to develop Norway as an offshore wind nation. Generating 30 GW of offshore wind power would result in nearly twice the current energy production and require approximately 1500 turbines. The Norwegian government has initiated efforts to identify potential new areas suitable for offshore wind power development along the lengthy coastline. During the pertinent press conference, the prime minister declared that the construction would occur within the next 20 years.

The ambitious offshore wind initiative will significantly boost Norway's green energy production, resulting in a more robust energy balance and maintaining the country's position in the energy industry. Additionally, this initiative will promote industry growth by offering affordable and environmentally-friendly electricity. The government also stated that this will be a major contribution to the green transition in Europe. 30 GW offshore wind power generated is too large for the Norwegian grid to accommodate, and it is therefore expected to be exported power abroad [12]. Several grid solutions will be considered to obtain an optimal utilization of the power production, including connections to continental Europe and offshore oil and gas platforms.

The government emphasizes that the process will be conducted with great care to ensure the protection of crucial interests as well as the stability of the power system. As a result, the allocation of areas will be conducted in stages to enable learning and adaptation throughout the process. Many factors must be considered when identifying locations for offshore wind farms. In addition to considering wind conditions, power demand and grid constraints, one must take into account fishing interests, environmental concerns, and potential human impacts. Moreover, the substantial increase in wind power production will have a significant impact on the Norwegian power system, which must be adequately prepared to accommodate this increased production. An important aspect regarding the effect on the power market will be how the power system will adjust to such a large share of intermittent power generation. The Norwegian energy mix has traditionally consisted of a large share of regulated power generation from hydropower. Wind power generation will be much less predictable, and the variation in production will largely affect the power market. To address these challenges, flexible hydropower production will play a key role in supporting the power system to cope with variability. Good knowledge of the planning and operation of flexible resources will be essential to ensure high supply reliability and avoid unnecessary price volatility. An adequately dimensioned transmission network capable of handling the increased power generation will also be essential.

1.2 Power market models

Power market models are essential tools when analyzing the future power system. These models are used by almost all market players in the power market, including transmission system operators(TSOs), power producers, regulators, consultants and researchers [13]. To ensure a sustainable energy system in the future, it is essential to make good investment decisions today. Relevant decisions include investment in cables to the continent, expansion of existing hydro plants or building new wind farms. In these situations, market models are essential to model the profitability and consequences of possible investments [13]. Furthermore, hydropower producers use models to schedule the water optimally. In these cases, parameters such as methodology, predicted inflow, head level and demand are important information to decide whether or not to produce.

Today, the EMPS model is widely used for long-term hydro scheduling in the Nordic countries. This market model aggregates the hydro reservoirs, which may give a better picture of the flexibility in the system than in reality, as the model does not take into account the restriction on each water reservoir. With an increasing share of intermittent renewable energy sources and closer connection with Europe, a model which correctly estimates the value of flexibility is needed to better respond to fluctuations in the system [13]. This motivated the development of the FanSi model.

FanSi is a fundamental hydro-thermal market model developed at SINTEF Energy Research as a result of the SOVN research project (2013-2017) [14]. The model uses a method called "Scenario Fan Simulator" (SFS), which combines optimization and simulation [13]. FanSi computes individual water values for each reservoir instead of aggregated water values as in the EMPS model. This has resulted in a more detailed representation of the hydropower system, which has shown to be beneficial regarding handling unpredictable fluctuations in unregulated generation. Nevertheless, the computation time has increased significantly, which is the main drawback of the model [15]. FanSi is currently a prototype, however, the methodology is well suited for the next generation of long-term hydro-thermal market modeling.

1.3 Objective

This master's thesis employs the market model FanSi to simulate various cases related to offshore wind power in Norway. The case study is based on the Norwegian government's plan to allocate areas for 30GW offshore wind power in Norway within 2040. A dataset representing a scenario for the Northern European power system in 2030 is utilized for the simulations. The objective of the analysis is to investigate the impact of 30 GW offshore wind power capacity on the Norwegian power system. The offshore wind production is directly transmitted to the nearest onshore area without any corresponding modifications made to the transmission system or power demand. The study investigates the effects on area price, transmission, hydropower production, and social welfare. Additionally, the study examines three distinct wind power capacity allocations to examine the impact of the wind farm locations.

The simulations are conducted on two different sets of wind series. This is done to analyze and compare the recently generated wind series by SINTEF Energy Research with the original wind series initially included in the dataset. This comparative analysis aims to provide valuable information for future studies utilizing the new wind series. Furthermore, it highlights the central role of wind series in case studies on wind power using market modelling.

Apart from its advantageous characteristics in systems with significant proportions of unregulated energy production, another crucial reason for selecting the FanSi model for this master's thesis is the objective of acquiring further insights and information about the model. Given that the model is still a prototype, conducting various simulations using the model is important in order to further validate its performance. Running the model on a dataset with large amounts of wind power production, without a corresponding rise in demand, offers the opportunity to acquire new insights into the model's capabilities and weaknesses.

1.4 Description of conducted work

The case study was formulated in collaboration with the supervisors, Magnus Korpås and Arild Helseth. Following the establishment of the case study, a literature review was conducted, focusing on the development of offshore wind power in Norway and wind power production's impact on the power market.

Server access was provided by SINTEF Energy Research, along with access to the necessary software and the dataset utilized in this master thesis. The software was thoroughly explored, utilizing the background understanding obtained from the project assignment. Furthermore, an initial effort was made to obtain an overview of the system structure described in the dataset. Multiple files within the dataset were examined to gain a comprehensive understanding of the system's state and the specific files included. Considering the significant rise in fuel prices in recent years, a decision was made to adjust the fuel prices within the dataset, as the original dataset was created prior to these events.

The scenarios investigated in this master project were determined in collaboration with the supervisors, based on the insights from the literature study and the framework provided by the dataset. In order to obtain the desired scenarios, modifications were made to the dataset by adjusting the wind capacity in the Norwegian offshore areas for each scenario. The simulations were performed using the market model FanSi, which was run on the server provided by SINTEF Energy Research. The simulation results were extracted as Excel sheets using the program "pckurvetegn", as well as a Python script provided by SINTEF Energy Research. To present the obtained results in the desired format, the student developed Python scripts.

The results were presented and discussed with the supervisors on an ongoing basis. Adjustments were made along the way to explore new aspects and achieve more realistic outcomes. During the analysis of the results, an issue arose concerning the water values calculated in EMPS, which serve as end values for the simulations in FanSi. It became evident that the substantial modifications made to the dataset, involving a significant increase in power production without a corresponding increase in demand, posed challenges in accurately calculating the water values in EMPS. To address this issue, additional simulations were conducted to test potential solutions and gain a deeper understanding of the problem. A simplified solution was identified, resulting in adjustments being made to the procedure for generating water values from EMPS in certain scenarios. Consequently, it became necessary to re-simulate some of the scenarios.

During the spring of 2023, SINTEF Energy Research generated a new set of wind series for the dataset, which initiated a study to compare them with the wind series initially included. The newly generated wind series were received on April 12, 2023. The wind series were first analyzed and plotted to study the consistency of the wind series and look for possible errors. Subsequently, new simulations were conducted for all scenarios, replacing the original wind series in the dataset with the newly obtained wind series.

1.5 Structure

The project is divided into ten sections. The first section introduces the motivation and objective of the project. Additionally, the conducted work is described in this section.

The second section covers theories that are relevant to the discussion of the results obtained in this thesis. The subjects described are power market fundamentals, water values and value factor.

The third section provides an overview of wind power, including technological facts, global and Norwegian development statistics, and cost reduction trends. It also introduces relevant research on the impact of weather on renewable power production in Norway, the influence of wind power on electricity prices, and case studies on offshore wind power in Northern Europe.

The fourth section presents the FanSi model used for the simulations, including a detailed explanation of the "Scenario Fan Simulator".

In the fifth section, the dataset utilized for the simulations in this thesis is presented, including a detailed description of the system represented within the dataset. Additionally, the section presents simulation specifications describing the simulation procedures and settings.

The sixt section presents the scenarios the study investigates.

The seventh section presents the results of the simulations, including wind power production, area prices, transmission, reservoir level, hydropower production and social welfare. These are presented for both the initial and new wind series.

The eighth section discusses the results from the seventh section, including the impact of 30 GW offshore wind power in Norway and the characteristics of the new wind series. This section also discusses the limitation and potential weaknesses of the study.

The ninth section summarizes the results of the project and forms a conclusion.

The tenth section describes future work that could be made based on the analysis conducted in this thesis.

Finally, the appendix includes more information about the dataset utilized in this thesis, as well as additional results from the simulations to validate the discussion.

2 Theory

Section 2.1 and 2.2 are reused from the preliminary project thesis written during the fall of 2022 [1].

2.1 Power market fundamentals

The power market is responsible for facilitating the exchange of electricity. There must always be an exact balance between generation and consumption, as electricity cannot easily be stored. As a result of the liberation of the power market, free competition between power suppliers was introduced. Furthermore, interconnections across borders open for an integrated European power market.

The main trading takes place in organized power markets. There are several power market operators in Europe, among these are Nord Pool and EPEX Spot. These offers trading in the day-ahead and intraday markets. In the day-ahead market, customers can sell or buy energy for the next 24 hours in a closed auction. Buyers and sellers have until 12:00 CET to submit their final bids for the auction for delivery hours the next day [16]. The hourly orders are matched to clear the market, setting power prices for each hour and each bidding zone. The intraday market offers trading closer to physical delivery. This market helps secure the balance between supply and demand, as unexpected changes in production and consumption may occur after the closing of the day-ahead market. This is especially challenging for intermittent renewable energy [17]. The intraday market is a continuous market, which usually closes one hour before delivery. After this, the TSO is responsible for ensuring momental balance in the power system. This is done through the balancing market, where the TSO can regulate supply and demand to ensure stability in the power system.

In addition to the organized power market, it is possible to trade outside the power exchange. This is called bilateral electricity trade. The amounts and prices in these exchanges are not made public [18].

2.1.1 Merit order curve

An illustration of the supply-demand curve for the energy market is shown in Figure 1. The supply curve is also called *Merit order curve*, going from the least expensive to the most expensive power technologies. The steps in the curve show the marginal costs and capacities of each generating plant [19]. The marginal costs for each unit are mainly determined by the technology used to generate the power. Renewable energy, such as wind and solar power, is placed on the lowest level of the curve, while costly fossil fuel energy is placed at the upper levels [18]. Moreover, the curved line represents the water values for hydropower production, further explained in section 2.2. The demand curve illustrates how demand varies with the price. A steep curve means that the demand is inelastic, meaning that it is not very sensitive to changes in price. Since electricity is a necessary good with few substitutes, the demand is often inelastic [18]. The firm demand at the top of the supply curve is the demand the system must cover to avoid rationing. Furthermore, the intersection of the demand and supply curve defines the market clearing price [20].

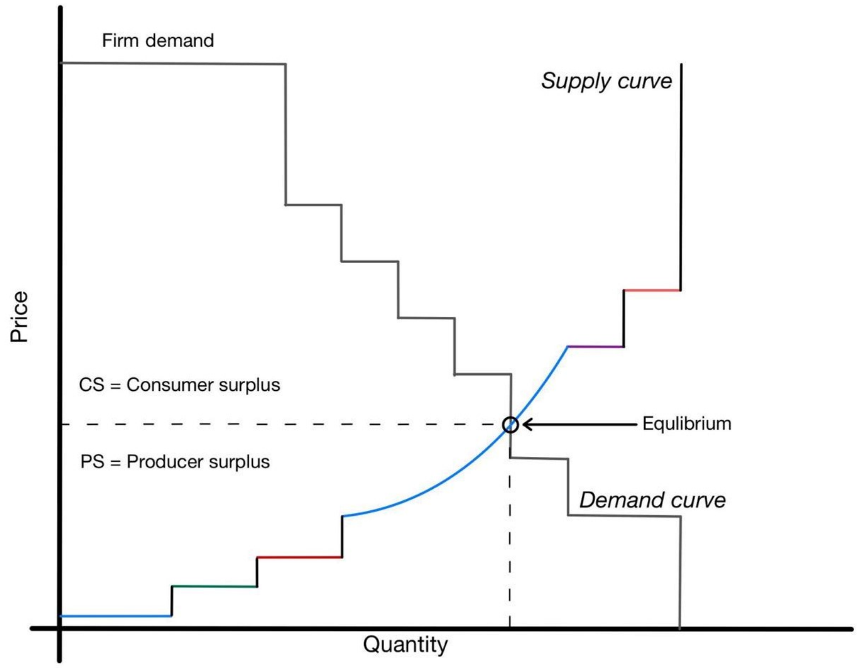


Figure 1: Supply-demand curve

The power price is chosen with the aim of maximizing social welfare. Social welfare describes what the society benefits in total over the trade and is represented by the sum of producer surplus and consumer surplus [21], illustrated in Figure 1. The consumer surplus is defined as *"the difference between what a consumer is willing to pay and what they paid for a product"*. The producer surplus is *"the difference between the market price and the lowest price a producer is willing to accept to produce a good"* [22]. Congestion rent due to transmission constraints is an essential component of social welfare and will be further explained in section 2.1.2.

2.1.2 Price areas

The power market must take into account grid constraints when clearing the market. This is done by splitting the market into so-called price areas. Price areas are defined as *"the largest geographical area within which market participants are able to exchange energy without capacity allocation"* [23]. The price areas are placed to reflect the bottlenecks in the power system, and the borders are therefore set where there is long-term limited capacity [24]. In Europe, most price areas are defined by national borders. Nevertheless, the Nordic countries have a different approach as it is split into twelve price areas.

The market price within a price area is always the same. However, price areas may get different prices due to bottlenecks in the transmission system. In this way, the prices reflect the regional market conditions. Transmission capacity constraints between two price areas always result in power flowing from the low-price area to the high-price area. This principle ensures that the power moves towards the area where the power demand is the highest [25].

Power trading between two price areas results in congestion rent. This is due to the consumer buying the power in the high-price area and the producer selling the power for a lower price. The congestion rent equals the transfer capacity multiplied by the price difference between the two price areas. The congestion rent goes to the TSO. In case different TSOs are affected, the congestion rent is split between them [21].

2.2 Water values

The ability to store water in a reservoir makes hydropower a highly flexible energy source. The water inflow to the reservoirs depends on weather conditions and is thus a stochastic variable. Despite the free inflow of water, the limited amount gives the inflow a value in terms of *opportunity cost* [21]. If the water is used today, we lose the opportunity to use it later. In order to ensure optimal use of the water, *water values* are introduced. The water value represents the expected value of a marginal amount of water if stored for later use [21]. Water values depend on the market's power demand and the quantity of water available. Generally, the water value is high when the reservoir level is low.

The objective of long-term hydropower scheduling is to ensure optimal utilization of the systems resources over a long time, normally up to 5 years [26]. In hydro scheduling, the water value is calculated based on the probabilities for various inflow scenarios. The traditional water value calculations used in EMPS are done by using backward stochastic dynamic programming (SDP) [21]. This approach is, however, not used for FanSi. When calculating water values using SDP, the time resolution for each stage is usually one week, and the state represents the discrete numbers of reservoir levels the reservoir is divided into. The procedure assumes that the final values are known. Therefore it starts with a set of assumed water values for the end of the year, week 52. Given that value, the corresponding generation level is decided. This leads to a reduced reservoir level, but at the same time, the reservoir is filled due to inflow. Therefore, a set of inflow alternatives are considered resulting in a set of corresponding water values depending on the final reservoir level. The probability of each inflow alternative is weighted to find the expected water values. This procedure is repeated for every discrete level in the reservoir. When continuing to week 51, the calculated water value from the earlier step is the starting point. The procedure is then repeated until we reach week 1. The water values at the end of the year should equal the start of the year value. If there is a difference, corrections must be made, and the water value must be recalculated. If the values are equal, convergence is made.

The decision on whether to produce or not is decided by comparing the water value with the market price. If the market price is higher, it would be advisable to produce. If it is lower, it may be beneficial to store it for a later time.

2.3 Value factor

The value factor is an important indicator when studying the value of an energy source. This factor compares the marked price of an energy source with the average spot price, to see how well these correspond [27]. The marked price of an energy source is determined by dividing the total revenue generated by the power producer during a specific time period by the amount of power produced. A value factor greater than 1 indicates that the price of electricity production for an energy source is higher than the average spot price. Consequently, the electricity produced is more valuable than the spot price during the time period [27]. On the other hand, if the value factor is less than 1, it means that the electricity generated is less valuable than the spot price.

The value factor is affected by how well the energy sources' production pattern adapts to the market demand. Generally, flexible energy sources have a higher value factor compared to intermittent energy sources. This is due to the fact that flexible energy sources can adapt their production to match high spot prices and consequently high demand. In contrast, intermittent energy sources generate electricity regardless of the market demand.

The value factor is calculated as:

$$\text{Value factor} = \frac{\overline{P}_{prod}}{\overline{P}} \tag{1}$$

where the average market price for the power producer, $\overline{P}_{prod}$, and the average spot price, $\overline{P}$, are defined as

$$\overline{P}_{prod} = \frac{\sum_{t=1}^{T}(p_t \cdot q_t)}{\sum_{t=1}^{T} q_t} \tag{2}$$

and

$$\overline{P} = \frac{1}{T}\sum_{t=1}^{T} p_t \tag{3}$$

where p_t is the spot price [NOK/MWh] and q_t is the power production [MWh] corresponding to time step t.

3 Wind power

Section 3.1, 3.2 and 3.5.2 are reused from the preliminary project thesis written during the fall of 2022 [1]. However, the statistics presented in section 3.2 have been updated for this master's thesis.

3.1 Technology

Wind power uses the kinetic energy created by air in motion to produce electricity. When the wind hits the turbine blades, causing them to rotate, the turbine connected to them turns. The rotation energy then moves a shaft connected to the generator, which generates electricity through electromagnetism [28]. The blades are angled to maximize wind production and minimize damage. If the wind speed is too high, the wind turbine will shut down to prevent damage. The axis of the wind turbine can be horizontal or vertical. However, horizontal-axis wind turbines are the most common type. It is desirable to place the wind turbines in places with stable and strong wind, as their performance is reliant on wind conditions. This can typically be hilltops and coastal areas.

Wind power production can be both onshore and offshore. Although onshore wind power is the most widespread, there has been an increase in offshore wind power in recent years. Building wind farms offshore provides better wind conditions, more space and fewer conflicts regarding human impact. The technology, however, has some challenges regarding the complex infrastructure, challenging working environment and increased stress to the components, making the cost higher [29]. Traditionally, offshore wind turbines have been fixed to the sea bed. However, in 2017 the world's first floating wind farm called Hywind Scotland started its production [30]. Floating wind turbines use anchors to keep them in place. This technology is revolutionizing the offshore wind industry as these wind turbines can be positioned in deeper sea areas. Allowing wind turbines in areas with higher wind potential opens for larger turbines with more generation capacity [29]. In addition, the installation process may be eased as the floating turbines can be built on land and towed to the offshore installation site [31].

3.2 Development statistics globally

Wind power is the leading non-hydro renewable technology and one of the fastest-growing renewable energy sources across the world. Of the total 899 GW wind capacity installed globally in 2022, 111 GW was established in 2020, 93 GW in 2021 and 75 GW in 2022 [32]. The remarkable capacity growth in China was the main reason behind the record capacity growth in 2020, which in turn resulted in a wind generation increase of 274 TWh (up 17%) in 2021 [33]. Onshore wind is still the most common technology, with a share of 93% of the installed capacity. Nevertheless, offshore capacity growth has surged in recent years, with globally installed capacity increasing from 34 GW in 2020 to 63 GW in 2022. This development is predicted to accelerate further in the coming years.

China is the largest wind power producer in the world, having 40.7 % of the installed capacity, followed by the US and Germany with 15.7 % and 7.4 % of the installed capacity, respectively [32]. Sweden is the leading country among the Nordic countries with about 14.5 GW wind capacity. Sweden is an offensive market player and entered the top ten wind markets in 2021 [34]. Denmark has a long tradition of wind power production, and nearly half of the Danish electricity production derives from this electricity source, making them the country with the largest share of wind in their energy mix [35]. In 2022, Denmark had an installed capacity of about 7 GW [32].

Ambitious targets have been set to boost offshore wind production. EU has set a target of an installed capacity of at least 60 GW by 2030 and 300 GW by 2050 [36]. Moreover, Great Britain aims to achieve a target of 50 GW by 2030 [37]. Several European countries have recognized the potential of offshore wind power production in Northern Europe. In 2016, the countries surrounding the North sea decided to further strengthen their cooperation, forming The North Seas Energy Cooperation (NSEC) [38]. This initiative will ensure coordinated development of a possible offshore electricity grid in the North Sea. In September 2022, the NSEC agreed to reach at least 260 GW of offshore wind by 2050, with an intermediate target of at least 76 GW by 2030 [39]. As for the Baltic Sea countries, a declaration of more cooperation in offshore wind was signed in August 2022. The countries committed to increasing the installed capacity from 2.8 GW to 19.6 GW by 2030 [40].

Despite the rapid growth in wind power production, more intensive development is needed to meet IEA's net zero emission by 2050 scenario. The scenario has approximately 7900 TWh of wind electricity generation in 2030. To reach this goal, it is necessary to raise annual capacity additions to almost 250 GW. IEA states that facilitating permitting for onshore wind farms and cost reduction will be the most critical factors [33].

3.3 Wind power production in Norway

Investments in wind power have increased significantly in Norway in recent years, from 874 MW installed capacity in 2016 to 5083 MW installed capacity today [5]. Norway experienced a particularly high growth in wind power generation in 2020, installing a total of 1532 MW throughout the year [5]. Wind power currently accounts for 10% of the Norwegian production capacity [3]. This represents 65 wind farms and a normal yearly production of about 16,9 TWh [5].

Despite the rapid increase in installed wind power in Norway in recent years, there are few onshore wind power projects planned for the upcoming years. The reason for this is the temporary stop in concession processing of new onshore wind power projects initiated by the Norwegian government in April 2019. The government's objective was to modify the concession process with the goal of placing a stronger emphasis on the impact of wind power projects on the landscape, environment, society, and neighboring communities, as well as strengthen local and regional participation [41]. In April 2022 the government again opened the concession process for new onshore wind projects, with the reservation that they have approval from the municipalities [42]. It is anticipated that the revised regulations for the concession process on onshore wind projects will come into effect in 2023. Onshore wind power projects typically undergo a concession process that lasts for approximately 6-7 years, meaning that new projects are unlikely to be operational until around 2030 unless measures are being taken to reduce the processing time [43]. Moreover, there is clear evidence that onshore wind power projects have resulted in conflicts over their impact on humans and the environment, thereby reinforcing the drive towards offshore wind power.

3.3.1 Offshore wind power

Until recently, the only operational offshore wind turbines in Norway were the floating turbines connected to the test centre METCentre, located off the coast of Karmøy. The first floating wind turbine, Hywind Demo (now Unitech), was installed here in 2009, while the turbine TetraSpar started its test period in 2021 [44]. A new turbine named Flagship, which will be the world's largest floating wind turbine, is currently under construction and the centre has recently gotten concessions for four new test spots [45].

In November 2022, Norway's first floating wind farm, Hywind Tampen, started its production in the Norwegian North Sea [46]. This wind farm is the world's largest floating wind farm with a system capacity of 95 MW. Hywind Tampen will provide electricity for the Snorre and Gullfaks oil and gas fields in the Norwegian North Sea, making it the first wind farm in the world to power oil and gas installations. Seven of the eleven wind turbines were put in operation at the end of 2022, while the remaining four are scheduled for 2023.

The Norwegian government's ambitions for offshore wind development in the country have initiated a process of identifying and opening up suitable areas for this purpose. In June 2020, the offshore areas Utsira Nord and Sørlie Nordsjø II were opened for renewable energy production [47]. This opening enabled the submission of concession applications for larger offshore projects on the Norwegian continental shelf, marking the first time such applications could be made [48]. The capacity opened for offshore wind power in Utsira Nord and Sørlie Nordsjø II are 1500 MW and 3000 MW respectively. However, more capacity is likely to be relevant in the long term. Utsira Nord is deep and therefore only suitable for floating offshore wind, while Sørlie Nordsjø II is suitable for both bottom-fixed and floating offshore wind. The first phase of the project, which includes a capacity of 1500 MW in each of the two offshore areas, was made available for tender in March 2023. The allocation of these areas is expected to be done by the end of 2023 [47]. Moreover, the Government has announced plans to initiate a new tendering process for offshore wind areas in 2025 [49]. The goal of the government is for the first offshore wind projects to be operational before 2030 [50]. The Norwegian TSO, Statnett, has been given the responsibility for the overall planning of the offshore grid, which is a fundamental aspect of offshore wind development. Sørlie Nordsjø II is especially suited for direct export of electricity to neighbouring countries due to its location. Nonetheless, the Norwegian government decided in 2022 that the 1500 MW capacity installed during the first phase of Sørlie Nordsjø II will be transmitted directly to the Norwegian mainland.

Despite offshore wind power representing a small share of Norway's current wind power production, the Norwegian government has significant ambitions for its future development. In May 2022, the Norwegian government presented a plan to identify areas for 30 GW of offshore wind power before 2040, which demonstrates its commitment to increasing offshore wind power production. If this goal is achieved, it would nearly double Norway's current energy production and significantly boost the country's position in the offshore wind industry.

3.3.2 Identifying new areas for offshore wind power in Norway

In 2010, The Norwegian Water Resources and Energy Directorate (NVE) identified 15 areas suited for offshore wind power production in Norway, shown in Figure 2 [51]. Moreover, an impact assessment on the 15 areas was conducted by NVE in 2012 to further explore the potential for opening the areas for wind power [52]. Two of these areas, namely Utsira Nord and Sørlie Nordsjø II, have since been opened for wind power production. Following the Norwegian offshore wind initiative presented in 2022, NVE where assigned by the Ministry of Petroleum and Energy to investigate if any of the 13 remaining areas should be reassessed for offshore wind development. The directorate was also assigned to assess whether new areas should be opened for offshore energy production and consider whether the utilization of space in the two opened areas can be increased. The areas identified should be equivalent to a minimum of 30 GW of offshore wind power [53]. Additionally, a schedule that enables the next allocation of offshore wind areas in 2025 should be made. The assignment was to be carried out by NVE in consultation with other directorates, including The Norwegian Petroleum Directorate, Environment Agency, Directorate of Fisheries, Coastal Administration, Directorate for Civil Protection and Defense Estates Agency.

As a part of NVEs efforts to identify areas for offshore wind production, NVE requested Statnett for input from a power system perspective. In February 2023, Statnett submitted a report that addresses this request [54]. The report states that an efficient distribution of offshore wind to various locations in the country, along with a well-planned co-location of production and consumption, can enable a future power system to manage significant volumes of offshore wind. Statnett's strategy to support the government's offshore wind power ambitions involves preparing the power system for 15 GW of offshore wind capacity by 2040. Statnett further emphasizes that before they can identify how to develop 30 GW of offshore wind in Norway, they require a significant amount of new information regarding consumption trends and the evolution of the power system. Moreover, such a development is expected to require further measures in the power system such as onshore grid development, more flexible consumption and changes in system operation measures.

Statnett provided recommendations for areas that should be made available for offshore wind development in 2025 and beyond. Expanding the already opened areas in Sørlige Nordsjø II and Utsira Nord may be relevant, and in such a scenario, it may be necessary to connect power to different connection points than those used in the first phase. However, Statnett emphasizes that, from a power system perspective, it would be advantageous to connect the next offshore wind farms to other locations in the country. The reason for this is that a large share of both offshore wind farms and cross-border interconnections is linked to the southern region, and since offshore wind production often is correlated with imports, this may cause an overload of supply in some periods [54]. Statnett recommends opening offshore areas that enable connection to Bergen and the Grenland area since they have the highest power demand and capacity in the grid. Other suitable offshore areas for wind power include Romsdal, Rana, and Sørlandet/Stavanger, as well as smaller amounts allocated to Haugalandet, Ålfoten and Hammerfest. Statnett emphasizes that additional areas may become relevant in the long term. Lastly, Statnett states that in a scenario with 30 GW offshore wind power in Norway, it is assumed that a portion of the offshore wind power will be linked directly to foreign countries or offshore industries. Statnett asserts that the offshore areas in Sørlie Nordsjø are most suitable for interconnections with neighbouring countries, based on their location. Hybrid systems would be most appropriate to connect to the southern region of Norway.

In April 2023, NVE submitted its findings to the assignment requested by the Ministry of Petroleum and Energy. This includes 20 areas identified for offshore wind development, presented in Figure 2. As seen in the illustration, 10 out of the 15 areas that were identified in 2010 are now considered unsuitable for offshore wind production. This is primarily due to more conflicts of interest in these areas compared to the identified areas, particularly because of the areas' proximity to the coast. These issues have become more evident in the current identification process as the updated database used in this process has helped to highlight these conflicts of interest more accurately [55]. In addition, advancements in technology, particularly in floating wind turbines, have opened up new areas for development further out to sea. This is beneficial as these areas also have fewer conflicts of interest [55]. The area that has been identified for offshore wind power development is 6 to 13 times larger than what is required to install 30 GW capacity. This has been done to provide flexibility for potential adjustments and reductions [56]. The next step in the process involves an impact assessment, which is expected to provide more knowledge that can be used to further define the areas. The government aims to allocate the first areas for offshore wind development in 2025.

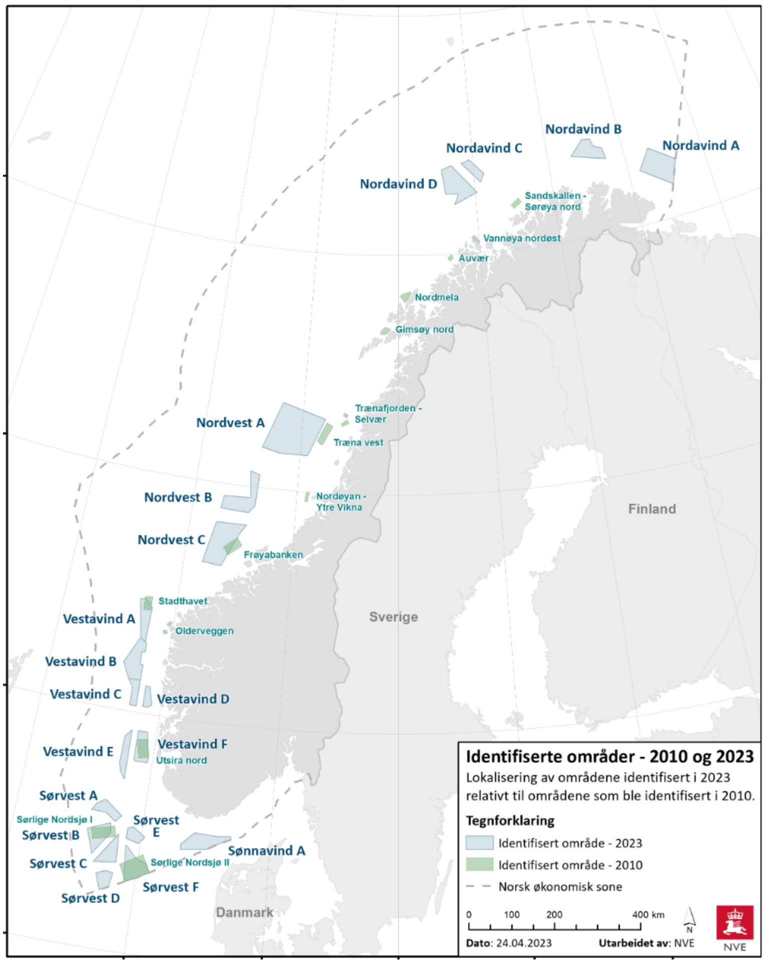


Figure 2: Areas identified by NVE in 2010 and 2023.
Source: NVE [55]

Factors evaluated in impact assessment for offshore wind farms
There are many factors that must be taken into consideration when identifying new areas for wind power production. NVE's impact assessment conducted in 2012 was categorized into three main areas of focus: environmental issues, business and societal interests, and technical prerequisites [52]. Environmental issues include the impact on sea birds, fish, marine mammals and benthic communities. Additionally, the impact assessment placed a particular emphasis on the environmental risks associated with the collision of a ship and a wind turbine, specifically with regard to the pollution of environmentally harmful substances.

The business and societal focus area evaluates the potential impact of offshore wind energy on other offshore industries including the petroleum industry, shipping traffic, and fishing industry. The impact on other land use such as defence interests, aviation interests, weather radars, pipelines and submarine cables was also discussed. Moreover, the consequences for landscape and outdoor life, cultural heritage and environment, as well as tourism are assessed. Finally, NVE estimated the possible employment value and value creation of offshore wind power development in the study areas.

Technical prerequisites are a fundamental part of assessing the potential for wind power production. Developing wind farms requires the opportunity to transfer wind power to the power system, which will depend on various factors such as electricity demand, grid capacity, exchange possibilities with other countries, and availability of flexible energy sources [52]. Moreover, the wind conditions in the area are an important factor in assessing its potential for wind power production. Lastly, the depth of the sea area and the distance from land will affect the choice of wind turbine technology as well as the accessibility, which in turn will have an impact on costs.

3.4 Cost reduction

The development of wind power is heavily influenced by the cost of installation and production, as the competitiveness of wind energy impacts the willingness to invest in this technology. Incentives provided by the government to boost investments in renewable energy have played a vital role in expanding the use of renewable energy and advancing technology. Nevertheless, the ultimate objective is for new renewable energy sources to become competitive. To achieve this, research and technological advancement are critical. The costs of energy sources are calculated using levelized cost of electricity (LCOE), which determines the average cost per unit of electricity produced. This is done by dividing the total cost of the electricity plant's lifetime by the expected amount of electricity it will generate during that time [57]. According to IRENA, the LCOE of an onshore wind farm is determined by the total installed costs, lifetime capacity factor, operation and maintenance costs, the economic lifetime of the project, and the cost of capital [58]. There is a significant difference in costs between onshore and offshore wind energy, and hence, the discussion of costs is segregated between the two.

IRENAs report "Renewable power generation costs in 2021" shows that from 1984 to 2021, the global weighted average LCOE for onshore wind projects has decreased by 90%, falling from 320 USD/MWh to 33 USD/MWh [58]. Moreover, the LCOE was 102 USD/MWh in 2010, indicating a 68% reduction over the decade leading up to 2021. Several factors have impacted this evolution. Turbine technology has been an important driver for cost reduction by leading to larger, more efficient and robust turbines that generate more power and require less maintenance [59]. This has also contributed to reduced operational and maintenance costs, along with the implementation of digital technologies and enhanced procedures [58]. IRENA also points to the economics of scale as a driver for cost reduction. An important motivation for the cost reductions in the wind power sector has been the competitor's auctions which drive competitiveness across the supply chain. The report from IRENA shows that onshore wind now has bypassed hydropower as the technology with the lowest global weighted average LCOG [58]. Moreover, statistics from NVE [1] show that onshore wind power currently is the cheapest energy source in Norway [60]. NVE predicts a further cost reduction in the future, from 28.7 USD/MWh in 2021 to 21.3 USD/MWh in 2030.

[1]All values are converted from Norwegian krone to US dollars using a rate of 1 NOK = 0.096 USD, based on the exchange rate as of March 31st, 2023.

Offshore wind power is more technically demanding and hence significantly more expensive compared to onshore wind power [61]. Nevertheless, offshore wind has also experienced a decline in costs in recent years. Data from IRENA shows that between 2010 and 2021, the global weighted average LCOE of offshore wind fell 60%, from 188 USD/MWh to 75 USD/MWh [58]. The progress is advancing rapidly and in Europe, the weighted average LCOE of newly commissioned projects fell 29% between 2020 and 2021, from 92 USD/MWh to 65 USD/MWh. This cost development has led to some offshore wind farms in Europe now being built without subsidies [54]. The drivers behind this trend resemble those for onshore wind power. In addition, policymakers have recognized the potential for offshore wind production, leading to substantial policy and regulatory support that reinforces this advancement. As floating wind turbines are an emerging technology, these statistics are primarily derived from conventional offshore wind turbines that are fixed to the seabed.

Due to the shortage of shallow offshore areas for fixed wind turbines in Norway, there is a drive to invest in floating wind turbines [61]. NVEs statistics on LCOE for energy sources in Norway separate between fixed and floating offshore wind turbines [60]. In 2021, the LCOE for fixed wind turbines was 66.3 USD/MWh and the LCOE for floating wind turbines was 111.9 USD/MWh. Moreover, NVE predicts a decrease in price within 2030 at 26% for fixed wind turbines and 42% for floating wind turbines, giving an LCOE of 49.0 USD/MWh and 64.9 USD/MWh respectively. NVE underscores the difficulty in estimating these values and highlights that they are based on assumptions. Moreover, in NVEs Long term power-marked analysis for 2021-2040 they estimated that it can be profitable to build bottom-fixed offshore wind turbines without subsidies before 2040 [10]. It should however be noted that the profitability of an energy source is also impacted by the power prices, which determine the revenue earned by power producers.

3.5 Relevant studies

3.5.1 Weathers impact on renewable power production in Norway

Norway has historically had a power system that is largely affected by weather due to a high share of hydropower. However, more unregulated power from solar and wind power in both Norway and Europe creates new challenges. Studying weather phenomena will therefore be important in order to better understand the future power system. The studies presented in this section are conducted by Koestler *et al.* for NVE [62], and Svendsen and Tande for SINTEF Energy Research [63].

NVE has published a report on how variations in weather will affect wind power, solar power and hydro inflow, and analyzed how these vary with the electricity consumption [62]. The study is based on historical data from 41 years. One of the main concerns defined by the study is the fluctuations in renewable energy production caused by weather variations. The fluctuating nature of wind and solar power production poses a challenge for the power system, as it makes it difficult to maintain an instantaneous balance between electricity generation and consumption. Moreover, on a yearly basis, hydro inflow varies more than wind and solar power which means that there are larger yearly variations in hydro production compared to solar and wind production. NVE emphasizes that the reservoir capacity is important in handling yearly variations in inflow, while batteries and consumer flexibility will be important in order to handle rapid variations caused by intermittent energy sources.

The study from NVE gives insight into common weather phenomena and how these may affect the power system. The study found that wind power production is highest in winter due to stronger winds, which is favourable as this is the period when the demand for power is highest and the hydro inflow is lowest. Nevertheless, on the coldest days with the highest electricity demand, there is not much wind blowing. Even though wind power can reduce the need for seasonal balancing of hydropower, wind power doesn't have the same effect in years with low inflow. This is due to meteorological phenomena, as low-pressure systems bring about high levels of rain and wind, while high-pressure systems result in little to no wind or rain. Moreover, periods with low inflow are often colder. Consequently, NVE found that years with low hydropower inflow often have low wind power production and cold weather. Higher power consumption and less access to renewable energy can weaken the energy balance during these periods. In contrast, periods of high inflow and wind production may challenge the power system as it leads to a lot of unregulated power production as well as lower energy demand.

Studying the variations in wind power between the Norwegian regions is important in order to determine the optimal locations for wind farms. When studying the short-term variations in wind, NVE found that correlation decreases with geographical distance, meaning that wind in the north and south of Norway has a low systematic correlation with each other. Moreover, the study found that the southern parts of Norway are correlated with northern European. South-West Norway has a stronger correlation with Denmark and South Sweden, compared to Germany, Netherlands, and Great Britain. The report emphasizes that placing offshore wind farms at different geographical locations along the Norwegian coast will result in more stable wind power production as the wind farms will produce at different times. Furthermore, when comparing offshore and onshore wind power the study found that the seasonal variations are pretty much the same, but the offshore wind is generally higher and more stable.

Following the offshore wind plans presented in May 2022, SINTEF Energy Research conducted a case study on 30 GW offshore wind in Norway [63]. The study is done using time series analysis based on a numerical weather model dataset. The analysis aims to answer the research questions of determining the optimal location for the wind farms and examining the potential impacts on the power system [64]. The case study utilized the 15 offshore regions identified by NVE in 2010 as sites for generating 30 GW of offshore wind power, allocating the capacity among the wind farms proportionally to their respective areas. Moreover, wind speeds covering the 29-year period from 1991 to 2019 were used.

The study from SINTEF examined wind variations in Norway and Northern Europe, similar to the NVE study, but based on the sites for the chosen offshore wind farms. The findings reveal that there is little to no systematic correlation between wind patterns between the wind farms in the south and those from central Norway and further north. As an example, there is no clear relationship between power output from Sørlie Nordsjø II and the wind farms in the north of Norway starting from Frøyabanken. Moreover, Sørlige Nordsjø I and II are strongly correlated with the European wind farms studied, namely Doggerbank in Great Britain, Horns Rev in Denmark and Baltic2 in Germany. Consequently, SINTEF supports NVE's recommendation of spreading wind farms across Norway instead of clustering them in a smaller area to provide a more stable offshore wind production which causes fewer challenges in balancing the power system.

SINTEF's findings further align with those from NVE, as they also concluded that wind power production is highest during winter, and therefore matches well with seasonal power consumption. Furthermore, the study examined low wind periods as this is important when identifying the need for alternative power sources, energy storage, and demand-side flexibility [63]. Results showed that the longest continuous period of less than 20% output from Norway's offshore wind parks observed over 29 years is about 4.5 days.

3.5.2 Influence of wind power on electricity prices

Several studies have been conducted to investigate the impacts of wind power on electricity prices. The overall finding is that electricity prices decrease with increasing wind penetration levels. Furthermore, the electricity price volatility increases, primarily due to the variability in wind [65]. The effect of increased wind power on electricity prices can be explained using the supply curve illustrated in Figure 1. As with other renewable electricity sources with zero fuel costs, the marginal price of wind power production is close to zero. Wind power, therefore, enters at a low level of the supply curve. An increase in wind power shifts the curve to the right, reducing the electricity price depending on the price elasticity of the power demand [18]. This is called the "Merit-order effect". In the peak power demand during the day, the impact is higher as we are at the steep curve where most available power sources are in use. However, at night the demand is low, and we are at the flat part of the supply curve, making the impact of wind power lower [66].

The "Merit-order effect" is defined as *"a shift of market prices along the supply curve due to the* *market entry of power stations with low production costs, typically zero or near-zero, displacing the power stations with the highest costs from the market"* [19]. A study from Figueiredo *et al.* [67] points out the challenges with this effect. The Merit-order effect is seen with concern by some electricity system stakeholders, as it contributes to displacing higher marginal costs technologies needed to support intermittent renewable energy. Furthermore, the lower wholesale electricity prices caused by renewable energy may cause insufficient remuneration of investment, the so-called "missing money problem". This determines a welfare transfer from suppliers to consumers. The study concludes that in the long term, investors will not have adequate signals to invest in the long-term capacity. To avoid this, the article encourages policymakers to address electricity market design urgently.

Helisö *et al.* [68] has studied the sensitivity of electricity prices in energy-only markets with large amounts of zero marginal cost generation. The study is based on the Northern European power system and simulates 2030 and 2050 scenarios with varying shares of variable generation. The analysis shows that an increasing share of variable generation decreases average electricity prices, however, the whole electricity price duration curve does not fall if the rest of the capacity mix is balanced. The article concludes that the amount of base load generation capacity and overcapacity has a more significant impact on electricity prices compared to the share of intermittent renewable and the cost of CO_2. Moreover, the study showed that a rising share of variable generation leads to a reduced need for base-load power plants and an increased need for peak-load power plants.

Producers of wind power use the weather forecast to estimate the expected production. When selling wind power in the day-ahead market, it is a risk of assessing wrongly. When over-forecasting, meaning that the wind is lower than expected, the undersupply must be covered either by purchasing from the intraday market or, as a last resort, from the balancing market [69]. A study from Brancucci Martinez-Anido *et al.* reveals that over-forecasting wind power increases electricity prices while under-forecasting wind power reduces them [65]. The study further states that the impact of under-forecasting is more significant than over-forecasting in terms of electricity prices. The main reason is that even though electricity prices increase largely due to ramping and start-up costs when over-forecasting, this is only for a short period. When the generation level is sufficiently high, the electricity prices will return to a lower level. On the other hand, under-forecasting may decrease the electricity prices to zero or negative values for long periods, depending on the wind conditions [69].

3.5.3 Case studies on offshore wind power in Northern Europe

The present master thesis investigates the consequences of increasing the share of offshore wind power in Norway using the market model FanSi. A dataset representing a scenario for the Northern European power system in 2030 is used for the analysis. Relevant research has been carried out to examine the outcomes of extensive wind power generation in Northern Europe and in particular the integration of variable power generation in a hydro-based power system. Previously established findings are here presented by the articles [70], [71], [72], [73] and [74].

Holttinen *et al.* [70] have studied the effects of large-scale wind power production on the Nordic electricity market using the fundamental hydrothermal power market model EMPS with weekly time resolution. The study uses two base case scenarios from the Nordic market area in 2000 and 2010, and integrates wind power in three stages resulting in annual productions of 16 TWh, 31 TWh, and 46 TWh in the Nordic countries (4.3 %, 8.2%, and 12.2% of electricity consumption). Although the study's state may not reflect current conditions, given its age, its findings remain relevant. The result from the study reveals that about 40 % of the added wind production is transferred out of the Nordic countries in the 2010 scenario. Signs of congestion in transmission become apparent, particularly towards Central Europe, once wind power generation exceeds 8% of the total electricity demand. Some transmission lines within Norway and to its neighbouring countries encounter more profound bottlenecks during wet years, while Sweden-Finland and internal Sweden have no significant surge in the use of transmission lines with increased wind production. Wind power replaces coal, oil, and some nuclear production, reducing CO2 emissions not only in the Nordic countries but also in Central Europe. Moreover, the results shows that adding wind power to the market lowers the spot price by 0.2 eurocents per 10 TWh/a wind production added in the 2010 scenario.

The article, [70], further uses various methods to evaluate the value of wind energy. When assessing the market value of wind energy, the study reveals that wind power generation would be valued, on average, approximately 1-2% more than the spot price, if no prediction error is taken into account. This implies that weeks with high prices would have slightly higher wind production compared to weeks with low prices. Furthermore, the avoided operating costs of thermal power is 3.3 eurocents/kWh for the lowest wind level and 3.1 eurocents/kWh for the highest wind level in the 2010 scenario. Finally, the study compares socio-economic surplus between reference and wind scenarios, finding wind energy's overall value to the market to be 4.4 eurocents/kWh at the lowest wind level and 3.9 eurocents/kWh at the highest wind level in 2010.

Vogstad [71] has also studied the value of wind power when investigating the system benefits of incorporating wind power in hydro production scheduling. In this study, the value of wind power is calculated as the difference in the production costs between the simulation with wind power and the reference case (without wind power) [71]. Using the EMPS model, a case study was conducted on the Mid-Norway region of Norway around the year 2000, with the integration of wind power ranging from 100 to 1000 MW into the system. The study showed that incorporating wind energy in hydro production scheduling increases the value of wind power. This is because of better management of the water reservoirs, due to the complementary characteristics of wind and hydropower, resulting in reduced water spillage.

Schäffer *et al.* [72] has quantified the value of flexible power generation technologies in Northern Europe in 2030, using the market model EMPS. Two scenarios were used for the Northern European power system in 2030. The reference scenario had 47% renewable power generation, while the low-emission scenario had 54%, reflecting more ambitious targets. The research is conducted in collaboration with HydroCen, employing the identical low-emission dataset utilized in this master's thesis. To assess flexibility, the plant's performance is calculated by comparing its realized power price to the average power price in the same area. This measures how well the plant can adjust to variations in power price. The study revealed that as the proportion of variable renewable energy sources increases, the realized power prices for wind and solar power plants, as well as Nordic hydropower generation, decline, while gas power plants in continental Europe see an increase. Still, for all flexible power plants the value of flexibility increases with increasing shares of variable renewable energy in the system. Moreover, the article highlights that limited transmission capacity limits the impact of price fluctuations in Central Europe on Norway, resulting in decreased price variations and flexibility value in the country.

Following the opening of Utsira Nord and Sørlige Nordsjø II in June of 2020, Kallset and Jaehnert [73] conducted a case study to explore how the impact of building an offshore wind farm is affected by how it is connected to the existing grid. The dataset used for the case study represents a reference scenario for Northern Europe in 2030. Four cases are analyzed using the power market model EMPS. Three of these cases consider different alternatives for connecting a wind farm located in Sørlige Nordsjø II to either Denmark (case 1), southern Norway (case 2), or both with an offshore hub (case 4). The final case focuses on investigating the effects of a wind farm located in Utsira Nord that is connected to Norway (case 3). All cases assume an installed generation capacity of 3 GW in Sørlie Nordsjø II and 1.5 GW in Utsira. The study verifies previous conclusions as the inclusion of an offshore wind farm leads to a reduction in the overall price level relative to the reference case. Although the effects of an offshore wind farm extend to other areas in the system, the connection point has a more significant impact on prices. Nevertheless, connecting both Sorland and Western Denmark to an offshore hub results in even lower prices for Denmark compared to a radial connection to the wind farm, as Sorland's lower price level contributes to further reducing the price in Denmark. Furthermore, the standard deviation generally increases, due to more variable production in the system leading to higher price variability. Nonetheless, Denmark stands out as an exception to this trend as its standard deviation decreases in case 2 and case 4 relative to the reference case. The authors states that this may be attributed to the supplementary energy mitigating energy shortage in certain situations.

When the article, [73], studies the effect on other stakeholders in the system, it is clear that the reduced prices results in lower producer surplus for hydropower and higher consumer surplus, with the most significant decline in hydropower revenue observed when the wind farm is connected only to Norway. Moreover, it is clear that the flexible hydro plant achieves higher prices than the offshore wind farm, as it is able to adjust its production to the price and remain unaffected by offshore cable losses. Furthermore, the value of combining intermittent wind power with flexible hydro is evidenced by the offshore wind power plant achieving a higher price when connected to Norway, despite western Denmark having a higher average price than southern Norway. The article concludes that the effects of the different cases on stakeholders, regions, and the total system vary greatly. From a system perspective, only case 2 and case 4 show a positive change in social welfare, with case 4 being the better choice.

NVE has also conducted a study on the offshore grid structure for Sørlige Nordsjø II [75] using the power market models TheMA og Samnett. This study focuses on the 1500 MW installed in the second phase of Sørlige Nordsjø II, as the 1500 MW capacity in the first phase was already decided to be transmitted directly to the Norwegian mainland prior to the study. The study states that the impact of the grid solution for phase 2 of Sørlige Norsjø II on Norwegian power prices is minimal due to the small increase in power capacity, and the fact that Norway is already exposed to price formation in Europe. However, it is clear that a radial connection to Southwest Norway would provide the greatest price reduction in all scenarios, benefiting consumers but negatively impacting other power producers in Norway, which is consistent with the findings from Kallset and Jaehnert [73]. Moreover, the study also confirms that a hybrid grid is generally more socio-economically profitable than a radial grid to NO2 due to bottleneck income from trading.

The total distribution effects in the reference scenario are marginal positive for the Norwegian power producers and marginal negative for the consumers. This is mainly due to the assumption of a power surplus in Norway as well as the hybrid grid solutions giving the opportunity to export more power from Norway during the low price period in the summer. With a reduced power balance in Norway, this situation may change as more power will be transferred toward Norway for the hybrid grid solution, resulting in lower power prices. Lastly, the study also referees to input from Statnett regarding the need for grid investments onshore due to the development of Sørlige Nordsjø II. Statnett suggested grid investments between the south and east of Norway, due to increased demand in the east and offshore wind development. Connecting the wind farm directly to Grenland may reduce the need for grid investments.

Graabak *et al.* [74] has studied the effect of Norwegian hydropower on the power balance in a 2050 Central-West European system with large shares of wind and solar energy resources. The case study is conducted using both EMPS and FanSi, giving the opportunity to compare the results from the two marked models. The cases analyzed reveal fluctuating power prices and occasional involuntary demand reduction due to intermittent renewable energy sources. Nonetheless, Norwegian hydropower almost eliminates the hours with load shedding and greatly decreases peak load prices. For instance, if Norway were to increase its hydropower capacity from the current level of approximately 30 GW to 41 GW, the average annual power prices would decrease by 10% or more in all simulated cases. The study therefore concludes that Norwegian hydropower has the potential to provide shares of the required flexibility and contribute to balancing the European power system. Moreover, the study shows that the possibility of pumping is crucial for fully utilizing the increased production capacity during periods of high prices.

When comparing the results from the EMPS model with the results from FanSi, the study, [74], finds that the result from the FanSi model demonstrates a greater reduction in power prices from increased Norwegian hydropower capacities than the EMPS model. Moreover, FanSi significantly decreases the level of price fluctuations. Consequently, the article states that FanSi manages to distribute the water in a more optimal way than the EMPS model. As the FanSi model accounts for more of the short-term hydropower flexibility as well as wind and solar production variations, this confirms its anticipated capabilities.

As this section illustrates, numerous studies have been carried out to assess the impact of integrating significant proportions of variable energy production into the power system. However, since the plans for developing 30 GW of offshore wind power in Norway were presented only recently, there are limited analyses conducted on this particular case. It is essential to conduct analysis on the effects of incorporating 30 GW of offshore wind power into the Norwegian power system, as such a significant amount of intermittent wind power will have a substantial impact. Moreover, examining this case through studies can assist in making decisions concerning critical factors for integration, such as determining the optimal location for wind farms, grid structures, and required transmission capacities. Most of the studies conducted on wind power integration in Northern Europe use the EMPS market model. With the integration of renewable energy sources, short-term effects have gained significance when modelling hydropower flexibility, making FanSi a viable option for future studies. FanSi has a more detailed representation of the hydropower system, which has shown to be beneficial in handling unpredictable fluctuations in unregulated generation. This was also confirmed by Graabak *et al.* [74] when comparing the results from EMPS and FanSi. Motivated by the stated considerations, the present thesis will use FanSi to investigate the effects of integrating 30 GW of offshore wind power in Norway on the Northern European power system.

4 FanSi

With the exception of a few improvements, section 4.2 is reused from the preliminary project thesis written during the fall of 2022 [1].

4.1 Introduction to FanSi

FanSi is a long-term hydro-thermal scheduling model developed at SINTEF Energy. The model was developed as a result of the SOVN ("Stochastic optimization model for Scandinavia with individual water values and grid restrictions") research project lasting from 2013 to 2017. The project was funded by the Research Council of Norway, Statnett, Statkraft, BKK and NVE [15]. The aim of the project was defined as *"to develop a new fundamental market optimization and simulation model able to solve the hydro-thermal scheduling problem with detailed description of all relevant constraints, including constraints given by individual hydro storages and plants using a formal optimization model"* [15]. It was necessary to develop a new model which better copes with the growing proportion of intermittent renewable energy sources and interconnections to Europe, as the currently used models, such as EMPS, were designed for a less variable power market. FanSi is therefore developed to better handle short-term effects like variable wind and solar resources, hourly pumping, ramping and transmission grid constraints [74].

Even though FanSi currently is a prototype, it has the potential to become the next generation long-term hydro-thermal market model. FanSi uses a method called "Scenario Fan simulator" (SFS), which combines optimization and simulation. Historical records for inflow are used to represent future uncertainty. The model is suitable for both operational planning and expansion planning studies [15]. FanSi differs from the currently used EMPS model, as it computes individual water values for each reservoir instead of aggregation. This facilitates better utilization of the hydropower system. However, it leads to a significant increase in computation time which is the main drawback of the model.

4.2 Scenario fan simulator

The term scenario fan is used for a two-stage stochastic linear programming problem and can be seen as a scenario tree with only two decision stages [13]. The second decision stage contains many time stages. All uncertainties are known in the first stage, while the uncertainties in the second stage are represented using scenarios. The simulator repeatedly solves sequences of the scenario fan until a solution has been found for the whole time horizon. The scenario fan problem and simulation logic will be further explained in this section.

4.2.1 Scenario fan problem

The scenario fan problem (SFP) is a stochastic optimization problem that is generally formulated as follows:

$$\mathrm{Z} = \quad \min\; c_1^T x_1 + \sum_{s=1}^{S} p_s c_{2,s}^T x_{2,s} \tag{4}$$

$$A_1 x_1 = b_1 \tag{5}$$

$$T x_1 + A_2 x_{2,s} = b_{2,s} \qquad s \in S \tag{6}$$

From the objective function Z shown in equation (4) it is clear that the objective of the SFP is to minimize expected costs. The first term in the objective function Z is the cost associated with the first-stage decision (x_1). The second term refers to the cost associated with the S different second-stage decisions ($x_{2,s}$), where S is the number of scenarios and p_s is the probability of occurrence for each scenario. Equation (5) holds the set of first-stage constraints, and equation (6) holds the second-stage constraints. In our case, the first stage state variables represent the reservoir levels in x_1. The technology matrix (T) in the second stage constraints connects the two stages by containing ones associated with the state variable from the first stage [13].

The SFP is illustrated in Figure 3 with five scenarios covering time stage 2-N. The filled circles are decision points and the branches are transitions. The first stage decision taken at time t_1 is not dependent on the scenarios, while the second stage decisions are related to one of the scenarios [13].

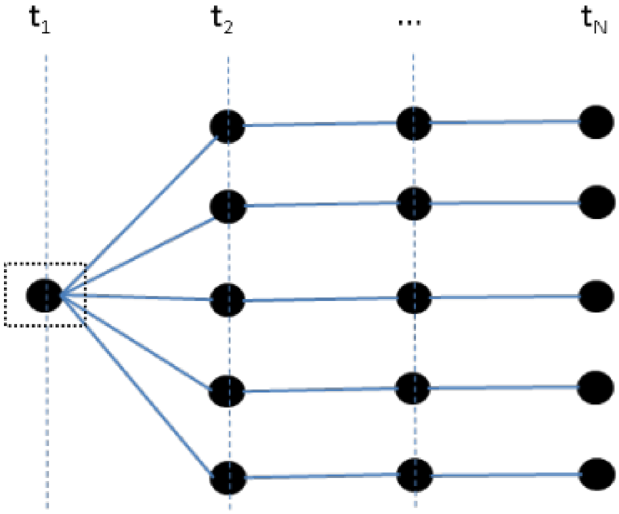


Figure 3: Illustration of SFP
Source: [13]

4.2.2 Benders decomposition

The two-stage SFP is solved using a decomposition technique called Benders decomposition. This technique decomposes the problem into a master problem and a sub-problem. The master problem represents the first-stage decision and passes the state variable solution (reservoir at the end of the first week) to the sub-problem. There are S second-stage sub-problems since each sub-problem represents the decision problem along one of the second-stage scenarios. The results from the sub-problem are used to construct a new linear constraint (cut) for the master problem. This iteration will continue until the difference between the upper and lower boundary of the master problem objective value is within a predefined tolerance. Compared to solving the extensive form, decomposition may lead to a significant decrease in computation time [13].

The stage-wise decomposition used in FanSi is described in [13] by the following:

A master problem is created to represent first-stage decision:

$$Z_{master} = \min c_1^T x_1 + \alpha \tag{7}$$

$$A_1 x_1 = b_{11} \tag{8}$$

$$\alpha + \pi^T x_1 \geq b_{12} \tag{9}$$

When the master problem is solved, the state variable solution (reservoir at the end of the first week) is passed to the sub-problem.

The first-stage decisions variables, corresponding to reservoir levels, are now set as parameters to the right-hand-side of the second-stage constraints as a trial solution:

$$Z_{sub}^{S} = \quad \min c_{2,s}^{T} x_{2,s} \tag{10}$$

$$A_2 x_2 = b_2 - x_1 \leftarrow \pi_s \tag{11}$$

Simplex multipliers, π_s, on the reservoir balances for the first load period in the second-stage are derived from the solution of a single sub-problem.

After solving all S second-stage sub-problems, the average multipliers, π_s, and right-hand side, b_{12}, are found to be used when constructing a new linear constraint (cut) for the master problem.

$$\pi = \sum_{s=1}^{S} p_s \pi_s \tag{12}$$

$$b_{12} = \sum_{s=1}^{s} p_s (Z_{sub}^{S} + \pi_s^T x_1) \tag{13}$$

The objective function value of the master problem will form a lower boundary. The lower boundary will gradually increase due to cuts constraining the future-cost function.

$$Z_{low} = Z_{master} \tag{14}$$

The upper boundary will be:

$$Z_{up} = c_1^T x_1 + \sum_{s=1}^{S} p_s c_{2,s}^T x_{2,s} \tag{15}$$

A decreasing upper boundary is enforced by letting:

$$Z_{up}^{i} = min(Z_{up}^{i-1}, Z_{up}^{i}) \tag{16}$$

The point of convergence is reached when the difference between the lower and upper boundaries is within a predefined tolerance. This occurs when:

$$Z_{up} - Z_{low} \leq \varepsilon \tag{17}$$

4.2.3 Simulation logic

The simulator repeatedly solves sequences of the scenario fan problem until a solution has been found for the whole time horizon. The first SFP contains stochastic variables according to scenario s_1 in the first time step t_1. Stochastic variables in the second decision stage, consisting of time steps $t_2 - t_T$, may take values of any of the S scenarios with equal probability. After solving the problem, the solution $sol(s_1, t_1)$ is stored, and the values of the state variables are passed on as a starting point to the next time-step t_2. After that, a new SFP is built with stochastic variables according to scenario s_1 in the first time step t_2. In this problem, the second decision stage consists of time steps $t_3 - t_{T+1}$. This sequence continues until a first-stage solution has been found for all time stages in the time horizon(t_1, T_N) for the particular scenario (s_1). This procedure is carried out for all scenarios $s_2 - s_S$. Note that an explicit end-value setting is needed for the model [13]. The end valuation is based on the water values from the EMPS model, and will be further explained in section 4.4.

The Scenario fan simulator logic is illustrated in Figure 4 where the SFP is built for a given scenario s_1 and time-steps t_1 and t_2 [13].

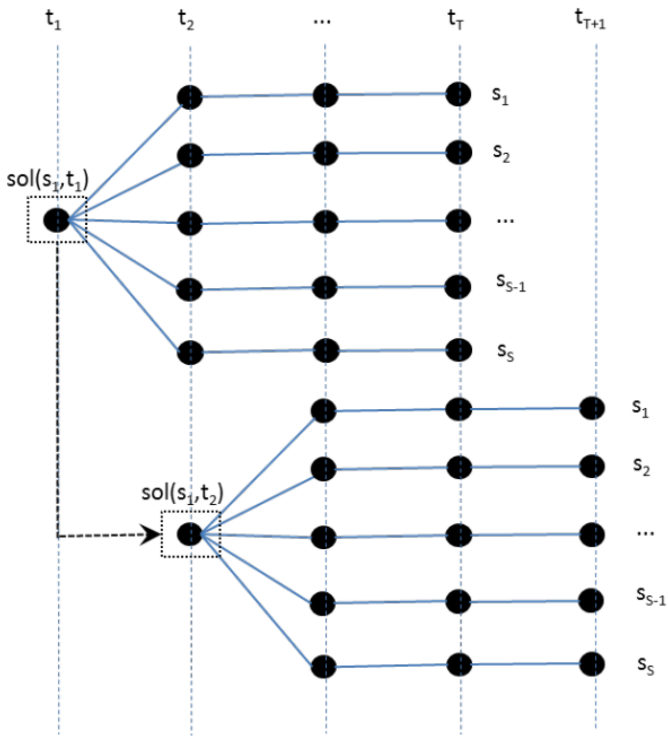


Figure 4: Illustration of SFS logic
Source: [13]

4.3 Scenario generating process

When simulating the future, several unknown variables must be handled. For a long-term hydro thermal scheduling model, these variables include inflow, exogenous power price, weather and temperature-dependent demand. FanSi handles future uncertainty using historical observations, which are represented through scenarios. As an example, a two year long scenario may represent the historical sequence 1983-1984. This method is based on the assumption that different historical sequences may repeat themselves and that each sequence has equal probabilities. FanSi uses a scenario fan to represent second-stage uncertainty, as described in the previous section.

The whole scenario generation process consists of four stages, here described for one specific inflow series for a given first-stage week in the future [15]. Firstly, the scenarios are given based on historical observations. Secondly, the inflow series are corrected for snow storage information. Since snow reservoirs can offer insight into future inflow, hydro scheduling models integrate information regarding the present snow reservoirs into the first year's spring flood forecast. Furthermore, a scenario reduction is performed on the snow-corrected inflows. This algorithm is implemented because solving each second-stage scenario problem is computationally demanding. The method used for scenario reduction in FanSi is described in section 4.3.1. The last step of the scenario generation process includes smoothing of scenarios based on known inflow in the first-stage week. This is done to avoid an unnatural change in the known value in the first stage to the first scenario value in the second stage [13].

4.3.1 Scenario reduction

The scenarios in the scenario fan are directly used historical scenarios representing second-stage uncertainty. Moreover, each scenario has an equal probability of occurrence. As solving each second-stage scenario problem is computationally demanding, a scenario reduction algorithm has been implemented in FanSi. The desired number of scenarios to be used in the fan is then specified by the user in the control input file. The objective of scenario reduction in stochastic optimization is to reduce the number of nodes in a scenario tree while minimizing its impact on both the probability distribution in the scenario tree and the optimal solution [15]. To ensure this, special scenario reduction techniques are used. The method for scenario reduction used in FanSi is based on the Fast Forward selection algorithm documented in [76]. By eliminating scenarios with the least probability-weighted distance to other scenarios and adjusting the probability of the nearest scenario to be the sum of both, this algorithm guarantees the preservation of scenario diversity. As a result, the scenario fan includes various types of weather years, despite not containing all the historical weather scenarios.

The method used for scenario reduction in FanSi is described in [15] as the following:

$$D_{ij} = \sum_{t=1}^{T} \sum_{n=1}^{N} (E_{nit} - E_{njt})^2 \tag{18}$$

Where

D_{ij}: Measure for the distance between scenario number i and scenario number j

E_{nit} : Value of scenario number i in timestep t unit n

N : Number of units (inflow series, wind series, exogenous price series)

T : Number of time steps

The reduction algorithm follows the steps described below to eliminate one scenario. This algorithm is repeated until the specified number of scenarios is obtained.

1. Calculate probability weighted distance to all other scenarios, $p_i \cdot Dij$, where p_i is the probability of scenario i.
2. Remove the scenario with the lowest probability weighted distance to another scenario.
3. Update probabilities for scenario p_j (assuming scenario i was removed, being closest to scenario j), $p_j = p_j + p_i$

In FanSi, the scenario value E_i [GWh/time step] is the sum energy of all inflow series plus all wind and solar energy production in the system for a given time step. The energy equivalent to sea [kWh/m^3] is used together with the amount of inflow at the given reservoir to find the energy [GWh/time step] for each inflow series [13].

4.4 End-value setting

When running FanSi, it is necessary to have an explicit end-valuation of reservoir content. The impact of the end-value setting on the result can be reduced by increasing the time horizon of the scenario fan. It is therefore desirable to run FanSi with a second-stage scenario covering a period of time long enough to limit the impact of the end-valuation of reservoir content [13]. Nevertheless, in practical cases, the length of the scenario must be reduced to decrease computation times. The scenario length can be specified by the user in the control input file. The main challenge when choosing scenario length is to find a balance between achieving reasonable computation times and taking into account the impact of end-valuation.

The end valuation is based on the water values for aggregated reservoirs from the EMPS model [15]. To calculate the end values, the reservoir volume is discretized into 2% intervals for a given individual reservoir. Then, a value is assigned to each segment, i, based on the following formula:

$$c_i = wv_i \cdot E \cdot R \tag{19}$$

wv_i: water value calculated for the aggregate reservoir e.g. in øre/kWh

E: the energy equivalent to sea from reservoir in kWh/m^3

R: the interest rate

In addition to the basic methodology described, FanSi incorporates certain aspects of the reservoir drawdown model in EMPS. Specifically, it utilizes information about individual target reservoirs, to include individual differences related to overflow risk and discharge flexibility [15].

The end valuation should be updated for larger changes in the dataset. This is done by using the EMPS model to recalculate water values. The updated water values are then used as input in Equation 19 when running FanSi, giving new end values.

4.5 Simulation and processing mode

4.5.1 Serial vs parallel simulation

FanSi can be run through serial- or parallel simulation. Parallel simulation is a mode where all scenarios use set initial reservoir levels as a common starting point [77]. Parallel simulation is normally used in scheduling where knowledge about the current system state is important [13]. This is typically operational planning, to find water values or to plan for the current period.

When conducting case studies concerning future system expansion, serial simulation is recommended. In these cases, the simulated results should not be significantly affected by the chosen initial state [77]. The simulation is then carried out for a future scenario, and the set initial reservoir level only applies to the first simulation year. After that, the end reservoir level of each year becomes the starting reservoir level for the next year.

4.5.2 Parallel processing

FanSi can be run with or without parallel processing. The processing is done using Microsoft's message passing interface (ms-mpi) [15]. Not using parallel processing involves running a model with a single process on a computer core, while parallel processing utilizes multiple processors on multiple computer cores [78]. Parallel processing in FanSi consists of two levels, where the first level is only used for parallel simulation. In this level, the scenarios in the scenario fan are distributed to groups. There are N groups, with each group handling a specific scenario and responsible for resolving a two-stage stochastic optimization problem. A group comprises M processes, where M can either be 1 or NSCEN+1 [78]. The second level includes solving the scenario fan problem using the processes within a group. Here, the most effective parallelization is achieved with NSCEN+1 processes, where one process is responsible for solving the first stage problem and the remaining processes solve a single scenario each [15].

4.6 Control input file

The control input file in FanSi is called *Fansi-ctrl.xml*. This file contains parameters and simulation specifications that can be adjusted to modify the behaviour of the model. By adjusting the values in the control input file, the user can explore the effects of different parameter settings on the behavior of the market model.

Below are some of the parameters listed in the control input file, along with their definitions as specified in the SOVN user manual [78]. A screenshot of the file can be found in appendix A.1.

> NWEEKSCEN: Number of weeks in the scenario-fan.
>
> NSCEN: Number of scenarios in the scenario-fan. If NSCEN is less than the number of available scenarios the model will use a scenario reduction method.
>
> LSEKV: Sets the time resolution of the master problem, which can be solved using either sequential time resolution (T) or accumulated time resolution (F).
>
> MAXDIFF: Gives the convergence criteria for Benders iteration process. A value between 1.0D-06 and 1.0D-04 is recommended, depending on the system.
>
> MAXITER: Sets the maximum number of iterations allowed in each Benders decomposition problem.

4.7 Price dependent steps

The file named *Trinnliste.txt*, found in appendix A.2, displays the price-dependent load and production (excluding hydro production) for each area. These can be interpreted as the steps shown in the supply-demand curve explained in section 2.1.1, each having a defined marginal cost. In FanSi, these steps are divided into categories, shown in Table 1 [79]. "Flomkraft" covers spillage power. Moreover, "Rasjonering" covers rationing, which is the only way to reduce the firm demand. The marginal cost corresponding to this step is the maximum price the system can obtain.

Table 1: Price dependent power categories

Category	**Automatic number**	**Name**
1		Tilfeldig kraft kjøp og import
2		Tilfeldig kraft salg og eksport
3		Varmekraft
4		Gjenkjøp fast kontrakt
5	900+	Trinn for kontrakter med delvis betalingsplikt
6		Kjøp spotmarked (prisrekke)
7		Salg spotmarked (prisrekke)
8		Kjøp referert lastprofil
9		Salg referert lastprofil
20	998	Flomkraft
30	400+	Pris-avhengige trinn fra faste kontrakter
40	999	Rasjonering

4.8 Wind series

Wind data inputs are given as wind series containing a value for each weather year for each time period within the year. The time resolution can be hourly, daily or weekly [15]. The wind series are based on historical observations and comprise data from a specific range of past weather years.

Each wind farm in the dataset is represented by individual wind series. The user can specify the wind power capacity in a wind farm by inserting a conversion factor, which converts the corresponding wind series to generation capacity. This is done by multiplying each value in the wind series by the conversion factor. The wind farm's maximum capacity can be calculated by multiplying the highest value in the wind series with the conversion factor.

All wind farms and their corresponding conversion factor are listed in the file *VINDSERIER.EMPS*. The wind series are represented as binary files in the file format *".W30"*.

4.9 Load periods

FanSi assumes a perfect market and only refers to the spot market of electricity. The week is divided into load periods for which a minimum time resolution of one hour is allowed [13]. The market clearing process is done for each load period and consequently, the power prices remain constant for the whole load period. The load periods can be accumulated or sequential. Accumulated load periods mean that each load period represents the accumulated result for the corresponding period for the whole week. As an example, within a week, there could be four load periods, with one of those periods comprising a total of 30 hours, representing the time frame of 08:00-14:00 from Monday to Friday. Sequential load periods are listed in the order they occur throughout the week, starting from the beginning of the week. This significantly increases the computation time compared to accumulated load periods [78]. The load periods can be seen in the file *PRISAVSNITT.DATA*, found in appendix A.3.

5 Dataset and simulation specifications

5.1 HydroCen2030 - Low emission

The analysis conducted in this thesis utilizes a dataset named *HydroCen2030 - Low emission*, which is developed at the Norwegian Research Centre for Hydropower Technology (HydroCen). This dataset represents a low-emission scenario for the Northern European power system in 2030. Compared to the HydroCen2030 reference scenario, the low-emission scenario reflects more ambitious targets [80]. This includes a larger share of power production based on solar and wind production. Moreover, all power production from lignite is phased out, and the coal-based capacity is reduced. It is also assumed that the transmission capacity from Norway to Germany and Great Britain will increase, leading to a doubling of capacity compared to the Reference scenario [80].

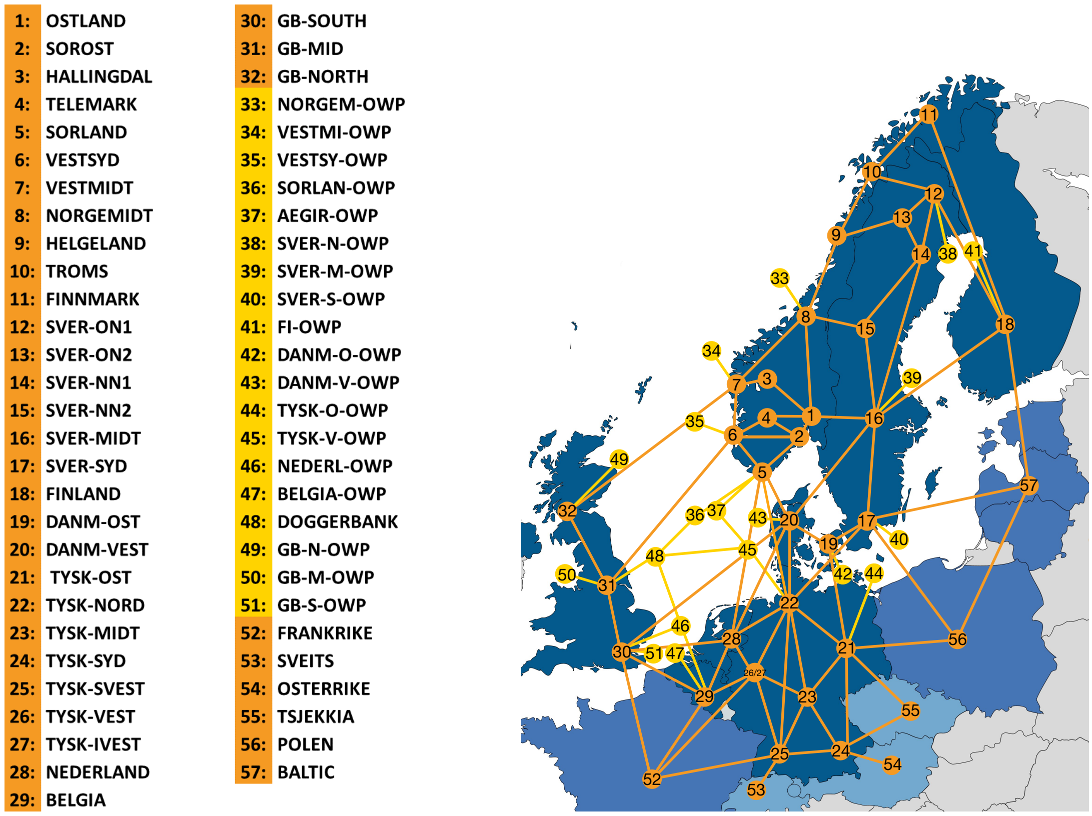
This section contains details about the system described in the dataset, including system structure, transmission capacity, firm demand, wind power capacity and fuel prices. Average annual power production and hydropower specifications can be found in appendix A.5. The system description presented in this section represents the system's condition in the base case. The modifications done to the base case in this case study are explained in section 6.

5.1.1 System structure

The system described in the dataset is a representation of the Northern European power system, and includes detailed modelling of electricity demand and supply in Norway, Sweden, Denmark, Finland, the Baltic region, Germany, Poland, the Netherlands, Belgium, Great Britain, and France [80]. The regions are described using 57 pricing areas, whereas 19 are offshore pricing areas. Norway is represented by 11 onshore areas and 5 offshore areas.

The hydro production in the system is represented through 1537 hydropower modules. 30 inflow scenarios, from the period of 1981-2010, are utilized in the simulations. The wind series included in the dataset are generated using NCEP/NCAR Reanalysis. The wind series covers a time span of 58 years, starting from 1958, with a time resolution of one hour. Loss occurs within the system's lines. The loss for the onshore lines ranges from 2-5%, while the lines to offshore wind farms experience a loss ranging from 1-3%. In Norway, the line loss in the lines connected to offshore wind farms is 1%, while the internal onshore lines experience a loss of 2%. The cross-border interconnections that lead out of Norway experience a higher line loss.

The system structure is illustrated in Figure 5. The darkness of the colour corresponds to the degree of detail in the representation of the countries, with the darkest shades indicating the highest level of detail. France, Poland and the Baltic region are each represented with one pricing area. The hydro production in these areas are aggregated into one reservoir. Switzerland, the Czech Republic and Austria are modelled with times series for power balance with corresponding deterministic prices. The remaining system exports power to meet demand or imports power from these countries, depending on the power balance during the given time period.



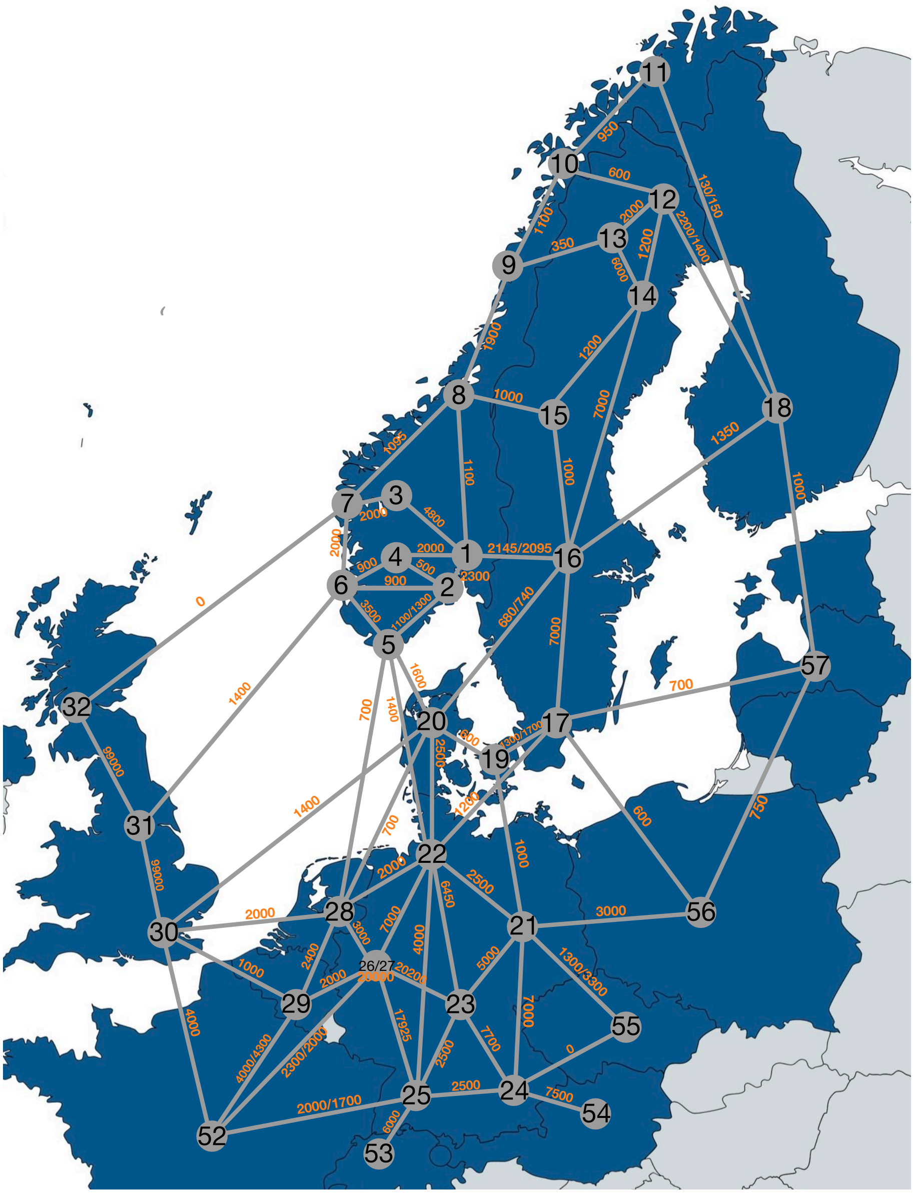
Source: Created with MapChart [81]

Figure 5: System structure in dataset

5.1.2 Transmission capacity

The transmission capacity in MW for all lines connecting onshore areas is shown in Figure 6. The transmission capacity shown on this map does not include the impact of line losses, so the actual transmission capacity is somewhat lower. The lines marked with two numbers (X/Y) have different transmission capacities in each direction, with X denoting the transmission capacity from the area with the lower area number to the area with the higher number.

Figure 6 does not include the lines connecting the offshore areas. However, these lines have sufficient transmission capacity to transfer the power generated from the offshore wind farms to the onshore connection point. Moreover, there is no power transmission in lines connecting two offshore areas, hence, the transmission capacity is zero in these lines.

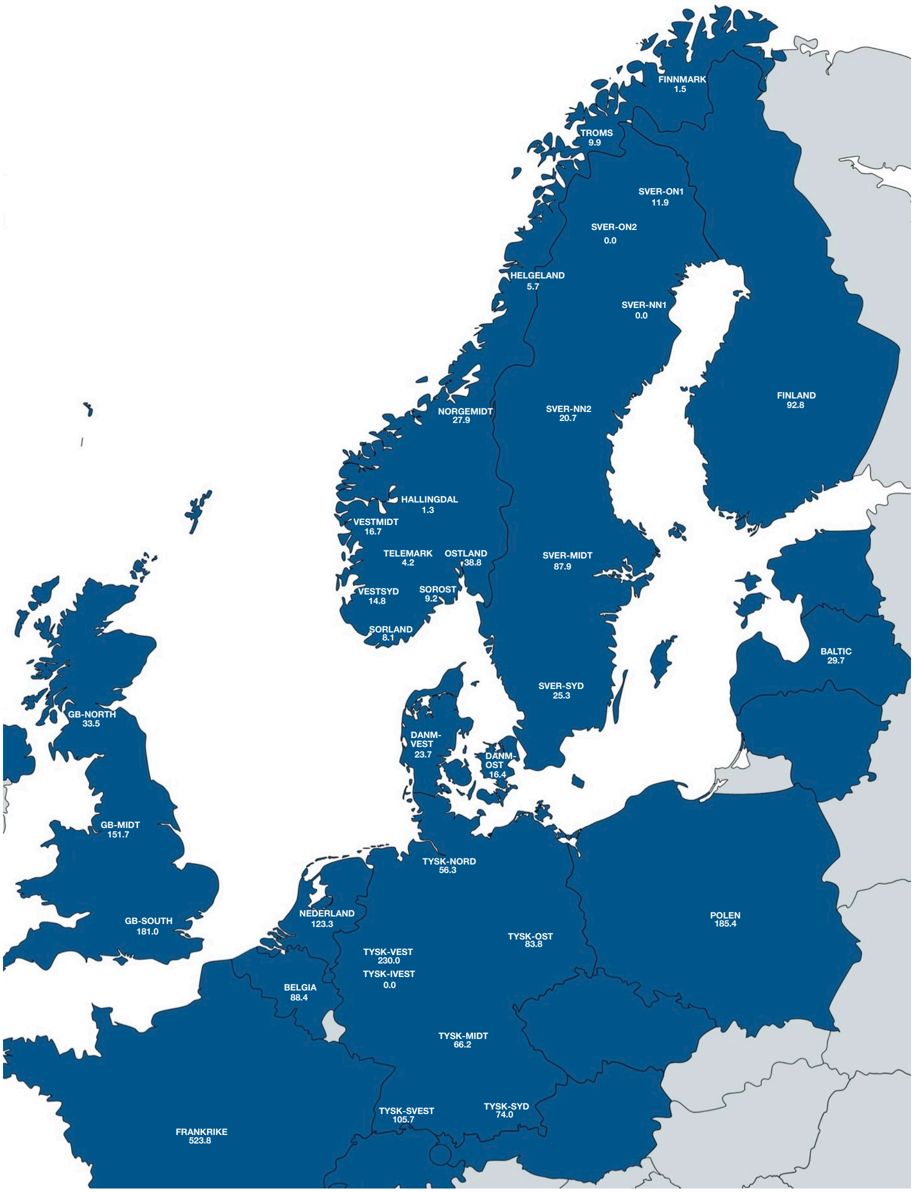


Source: Created with MapChart [81]

Figure 6: Transmission capacity in MW for the lines connecting the onshore areas

5.1.3 Firm demand

The mean yearly firm demand in TWh for the onshore areas in the system is shown in Figure 7. The offshore areas have zero firm demand. The firm demand represents the minimum demand that must be covered at all times and that can only be reduced through rationing. The rationing price is 30 000 NOK/MWh.

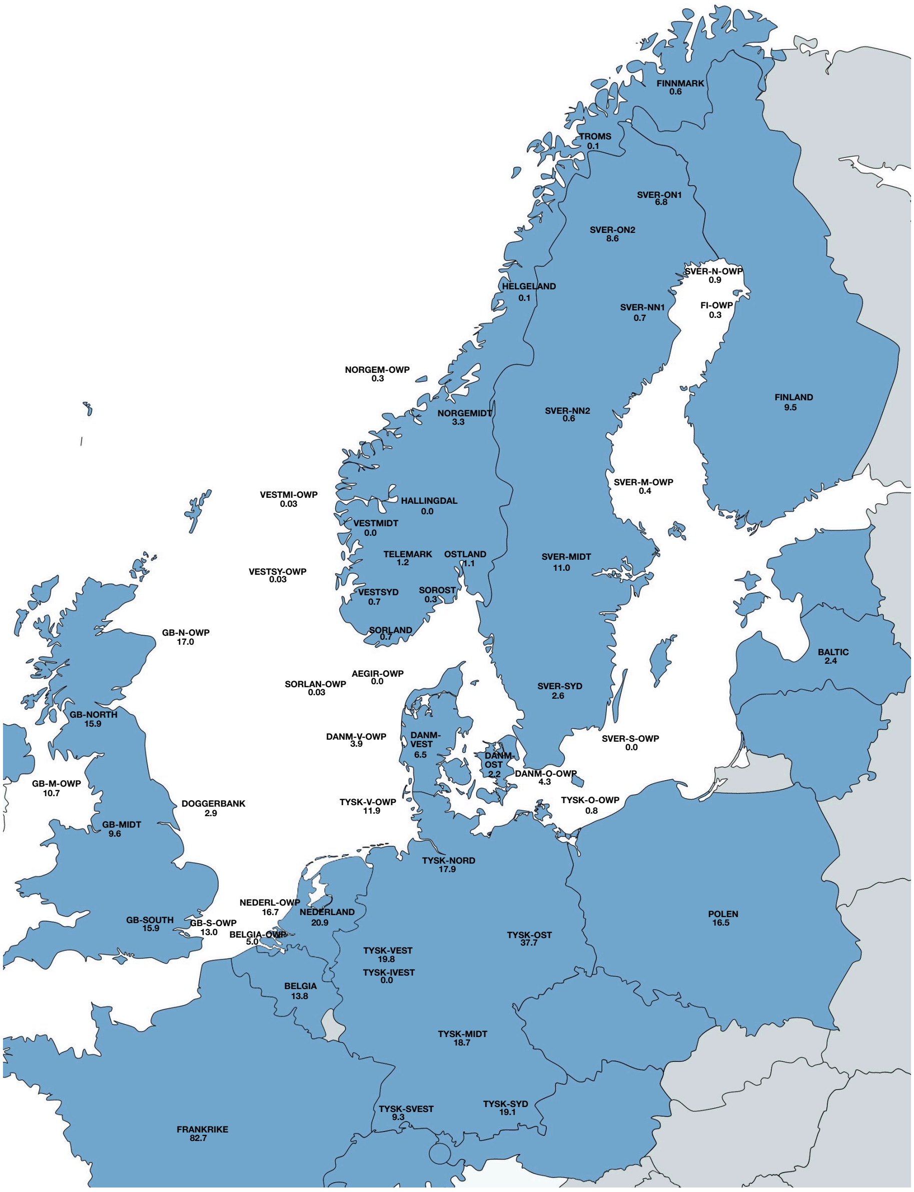


Source: Created with MapChart [81]

Figure 7: The mean yearly firm demand in TWh for the onshore areas in the system

5.1.4 Wind power capacity

The wind power capacity in GW for each area in the system is shown in Figure 8.



Source: Created with MapChart [81]

Figure 8: The wind power capacity in GW for the areas in the system

5.1.5 Fuel prices

The fuel prices used in the simulations conducted in this thesis are listed in Table 2. These prices have been multiplied by a factor of 1.5 compared to the values included in the original dataset. This is done to account for the recent years surge in fuel prices caused by the economic recovery after the pandemic and the Russian invasion of Ukraine in February 2022 [82]. The fuel prices have fallen and stabilized at a lower level since the record level of over 340 EUR/MWh for EU gas prices in August 2022 [82]. Nevertheless, it is assumed that the recent events have caused fuel prices to remain at a higher level compared to those defined in the dataset created prior to these events. The assumption that gas prices will be around 30 EUR/MWh in 2030 is the basis for the increase in fuel prices. This assumption is substantiated by the forecasts made by Rystad Energy

[83], Sverre Aam for SINTEF Energy Research [84] and the Basis-scenario in Statsnetts Long Term market analysis 2022-2050 [85]. A simplified assumption is made assuming that the other thermal technologies will experience the same growth as gas, resulting in a 1.5 increase for all fuel prices compared to the original dataset.

The CO_2 tax is 110 EUR/tCO_2, which is consistent with the original dataset.

Table 2: Fuel prices

Fuel	**CO_2-emission [CO_2/unit[1]]**	**Energy coeff. [MWh/unit]**	**Price [EUR/unit]**
Bio	0.00	3.50	45.00
Lignite	2.05	4.10	153.00
Coal	2.92	7.90	153.00
Gas	0.20	1.00	31.50
Oil	0.20	1.50	139.50

5.2 Simulation specifications

The simulations are conducted using a server operated for SINTEF Energy Research. FanSi is run using the optimization solver CPLEX. The simulations are done using serial simulation and parallel processing. Serial simulation is chosen as this is recommended for case studies concerning future system expansion.

The base dataset used as input to FanSi consists of several input files containing information about the system. This includes information about the systems topology, descriptions of the hydro reservoirs in each area, wind series and simulation specifications. Changes in wind power capacity are done in the command window using the program *ENMDAT* to change the conversion factor in the ENMD-file for each area. When changing the wind capacity using the conversion factor, the program *Samtap* (EMPS-model) has been run in order to ensure that the desired wind capacity is obtained. If not, the conversion factor is adjusted once more. *Samtap* is used for these tests as it has a significantly lower running time compared to FanSi. The transmission capacity of the lines to the wind farms is adjusted in some scenarios to prevent any constraints on the transmission of offshore wind power to the onshore area. Changing the transmission capacity is done directly in the file *MASKENETT.DATA*. Moreover, the fuel prices are changed directly in the file *BRENSEL.ARCH*, shown in appendix A.4. New wind series have been added to the dataset by replacing the initial wind series files with the new ones. The new wind series files were given the same name as the ones initially included. The conversion factors were then updated for the offshore areas included in each scenario in order to ensure the same wind power capacity in the wind farms for the scenarios with the new wind series.

Running FanSi is done by opening the command window in the dataset. After activating a startup script that sets the simulation environment, it is possible to start the simulations. This is done by inserting the code *mpiexec -n X sovn_cplex_ms_ mpi*, where *X* is set equal to the number of processes. Up to three simulations were run simultaneously, each taking around 3 days to complete.

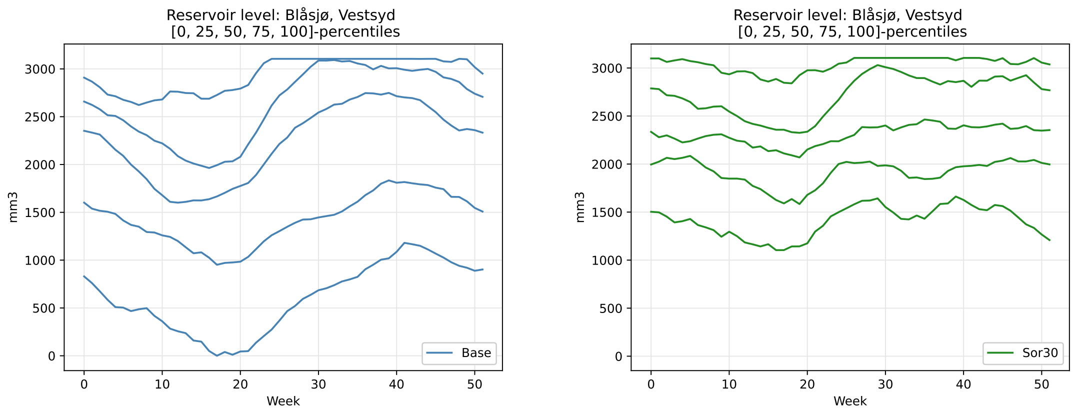
The simulation results were extracted using the program *pckurvetegn*. A Python script provided by SINTEF Energy Research has also been used to extract results. The results are primarily extracted as Excel sheets with results for each of the 30 weather years. Python scripts have been made to process these Excel sheets and present the results in the desired format. Social welfare is found using the program *Samoverskudd*. In this program, social welfare is calculated as the sum of producer surplus, consumer surplus, the surplus of the transmission system operator and the costs of reservoir changes. The programs *pckurvetegn* and *Samoverskudd* are included in the SINTEF server and opened directly in the command window.

[1]The unit is "MWh" for gas, "mmbbl" for oil and "ton" for bio, lignite and coal.

5.2.1 End value setting

This thesis primarily focuses on FanSi rather than the EMPS model, as FanSi is utilized for the simulations conducted. However, due to an issue concerning the end valuation, additional attention was required to be given to the EMPS model. As previously described in section 4.4 it is recommended to update the end-value setting after modifying the dataset to ensure accurate end valuation for each simulation. Consequently, for each scenario simulated in this thesis, the end value setting is updated by running *Saminn* before running FanSi. Saminn functions as a wrapper for various programs, including tasks such as data preprocessing, calculation of water values for aggregated reservoirs, and simulation.

During the analysis of the results, it was observed that the reservoir levels in selected reservoirs showed suboptimal outcomes for the scenarios with high levels of wind power production. This can be illustrated by studying the reservoir level in Blåsjø, Norway's largest hydro reservoir, for the scenarios Base and Sor30, displayed in Figure 9. Base includes zero offshore wind power production in Norway, while Sor30 has 30 GW offshore wind capacity installed in the south of Norway. When studying the reservoir level in Base, it can be observed that the percentiles are evenly distributed, indicating considerable variability in reservoir levels across different weather years. This means that the reservoir is flexible and capable of adapting to changing weather. The reservoir level for Sor30 is significantly higher, with the percentiles clustered within a narrower range. This indicates that the reservoir is not operating optimally, as it would be preferable to utilize more of its capacity. To address this issue, the end value setting was studied, revealing that the water values derived from the EMPS model were excessively elevated. This observation indicated that the high reservoir level for scenario Sor30 could be attributed to the end value setting.



(a) Base

(b) Sor30

Figure 9: Reservoir level in Blåsjø when updating the end value setting by grouping the areas in the water value calculations

In the process of addressing the issue with the end valuation, it was found that selecting the "Ingen grupperinger" (No groups) option when running Saminn, resulted in lower water values from EMPS and consequently a more balanced reservoir level for the scenarios with 30 GW wind power capacity. This approach calculates the residual load separately for each area, deviating from the default option where it is calculated for distinct groups of areas known as "Samkjøringsområder". Based on this finding, a potential explanation for the issue observed in the water value calculations in EMPS could be the occurrence of negative residual load resulting from the significant wind power production in the system without a corresponding rise in demand. This problem appears to be less pronounced when calculating the residual load for individual areas rather than groups of areas. To potentially address this issue while still utilizing groups, one could explore different arrangements of areas within each group to find better combinations. However, the simplest solution would be to avoid grouping the areas.

In consultation with the supervisor from SINTEF Energy Research, it was decided not to group the areas when calculating the water values in EMPS for the scenarios with 30 GW offshore wind capacity, namely Sor30, Mid30, and Nor30. For the scenarios with lower levels of wind power, specifically Base and Sor4.5, the end-value setting is calculated according to the original plan. It is important to acknowledge that there are uncertainties regarding the underlying reasons for the issues related to the end value setting. While efforts have been made to investigate and address this problem in collaboration with the supervisors, more time would be required to gain a deeper understanding of this issue. Based on the obtained results, not grouping the areas in the water value calculation using EMPS was considered the most suitable solution for the simulation conducted in this thesis. It should be noted that calibration factors in the EMPS model were not changed after modifying the datasets. Updated default calibration factors would probably have improved the water values. However, as the focus of this thesis primarily is on FanSi rather than the EMPS model, model calibration was not prioritized. Lastly, it is important to emphasize that the water values obtained from the EMPS model are solely utilized for the end-value setting. Increasing the time horizon of the scenario fan mitigates the impact of the end-value setting on the results. However, due to the associated increase in computational time, further extending the time horizon was not done in the simulations conducted in this thesis.

5.2.2 Parameters in the control input file

The values chosen for some of the parameters listed in the control input file is shown in Table 3. The simulations conducted in this thesis utilize 8 scenarios in the scenario fan and a scenario length of 52 weeks. These parameters are decided in order to strike a balance between model runtime and result accuracy. The result from the analysis on parameterization in FanSi, conducted by Jeyaseelarajah and Ljøkjels [86], was taken into consideration when selecting these values.

Table 3: Selected parameters in the control input file

Parameters	**Value**
NWEEKSCEN	52
NSCEN	8
LSEKV	F
MAXDIFF	0.99999997D-05
MAXITER	10

5.2.3 Load periods

For the simulations conducted in this thesis, the week is divided into 56 load periods, each with a time resolution of 3 hours. The simulations are done for sequential load periods, where the load periods are listed in the order they occur throughout the week. Consequently, load periods 1-8 are assigned to Monday, load periods 9-16 are assigned to Tuesday, and so forth for the remaining days. An overview of the load periods is presented in Table 4.

Table 4: Overview of the load periods

Load period nr	**Days**	**Hour**
1, 9, 17, 25, 33, 41, 49	Mon-Sun	00-03
2, 10, 18, 26, 34, 42, 50	Mon-Sun	03-06
3, 11, 19, 27, 35, 43, 51	Mon-Sun	06-09
4, 12, 20, 28, 36, 44, 52	Mon-Sun	09-12
5, 13, 21, 29, 37, 45, 53	Mon-Sun	12-15
6, 14, 22, 30, 38, 46, 54	Mon-Sun	15-18
7, 15, 23, 31, 39, 47, 55	Mon-Sun	18-21
8, 16, 24, 32, 40, 48, 56	Mon-Sun	21-24

6 Overview of simulated scenarios

To examine the consequences of 30 GW offshore wind power production in Norway, this thesis investigates five scenarios with different levels of offshore wind power production. The first scenario assumes zero offshore wind power production in Norway, while the second scenario assumes 4.5 GW offshore wind capacity. The remaining three scenarios assume 30 GW offshore wind capacity in Norway, allocated at different locations. In order to prevent any restrictions on the transmission of offshore wind power to the connecting onshore area, the transmission capacity of these lines is adjusted accordingly in each scenario.

In the spring of 2023, SINTEF Energy Research generated a new set of wind series for the dataset, which initiated a study to compare them with the wind series initially included in the dataset. As a result, each of the five scenarios is simulated using both the initial wind series and the new wind series. The new wind series span over 43 years, from 1979 to 2021, with a time resolution of one hour. The wind series were generated using ECMWF-ERA5 meteorological data, which provides higher geographical and temporal resolution compared to the wind series initially included in the dataset.

In total, 10 scenarios were simulated and are included in the overview presented in Table 5. Detailed descriptions of the offshore wind scenarios are given in section 6.1.

Table 5: Scenario overview

	Default dataset	**New wind series**
Base	Base	Base-W
Sor4.5	Sor4.5	Sor4.5-W
Sor30	Sor30	Sor30-W
Mid30	Mid30	Mid30-W
Nor30	Nor30	Nor30-W

6.1 Offshore wind scenarios

Base

In this scenario, there is no offshore wind power in Norway. This scenario serves as a benchmark for evaluating the impact of offshore wind power in Norway.

The scenario has been implemented in the dataset by setting the transmission capacity in the lines towards Norgem-OWP, Vestmi-OWP, Vestsy-OWP, Sorlan-OWP and Aegir-OWP equal zero.

Sor4.5

This scenario reflects the first step towards the Norwegian government's ambition of allocating areas for 30 GW offshore wind by 2040. In June 2020, the offshore areas Utsira Nord and Sørlie Nordsjø II were opened for renewable energy production, with capacities of 1.5 GW and 3 GW, respectively [47]. The first phase of the project was opened for tender in March 2023, marking the first time larger offshore projects could be applied for on the Norwegian continental shelf.

To simulate offshore wind production in Utsira Nord and Sørlie Nordsjø II, the capacity is added to the nearest offshore area in the dataset, resulting in 3 GW in Sorlan-OWP and 1.5 GW in Vestsy-OWP, as shown in Table 6. Production in other Norwegian offshore areas is set to zero.

Table 6: Allocation of 4.5 GW offshore wind capacity in Sor4.5

Area	**Capacity [GW]**
Sorlan-OWP	3
Vestsy-OWP	1.5

Sor30
In this scenario, 30 GW offshore wind capacity is concentrated in the southern part of Norway, to examine the effect of locating all wind farms in a smaller area. The allocation of the offshore wind capacity in this scenario is shown in Table 7. Production in other Norwegian offshore areas is equal to zero.

Table 7: Allocation of 30 GW offshore wind capacity in Sor30

Area	Capacity [GW]
Sorlan-OWP	15
Vestsy-OWP	15

Mid30
In this scenario, 30 GW offshore wind capacity is distributed across the five offshore areas in the dataset, resulting in a spread of capacity from the south to the mid of Norway. The capacity is allocated equally across all offshore areas, as shown in Table 8.

Table 8: Allocation of 30 GW offshore wind capacity in Mid30

Area	Capacity [GW]
Aegir-OWP	6
Sorlan-OWP	6
Vestsy-OWP	6
Vestmi-OWP	6
Norgem-OWP	6

Nor30
The distribution of the wind capacity in this scenario is based on the 15 offshore regions identified by NVE in 2010 as potential sites for generating 30 GW offshore wind power, which can be seen in Figure 2 [51]. The allocation of the 30 GW capacity among the wind farms is proportional to their respective areas, following the allocation used by SINTEF Energy Research in their case study on 30 GW offshore wind in Norway [63]. An overview of the allocation of wind capacity and corresponding wind farms for each area in the dataset is shown in Table 9.

Since there are no offshore areas connected to Helgeland, Troms and Finnmark in the dataset, the offshore wind capacity in this region has been added directly to the onshore areas. This simplification is not expected to significantly affect the results, as the transmission capacity from the offshore areas is high enough to prevent congestion in the transmission to the respective onshore areas in all scenarios. Nevertheless, this approach does not account for transmission losses and may result in lower wind conditions compared to offshore sites.

Table 9: Allocation of 30 GW offshore wind capacity in Nor30

Area	**Wind farms**	**Capacity [GW]**
Sorlan-OWP	Sørlige Nordsjø II Sørlige Nordsjø I	13.746
Vestsy-OWP	Utsira Nord	3.501
Vestmi-OWP	Frøyagrunnene Olderveggen Stadthavet	2.268
Norgem-OWP	Frøyabanken Nordøyan - Ytre Vikna	3.326
Helgeland	Træna vest Trænafjorden - Selvær	3.365
Troms	Gimsøy Nord Nordmela Auvær	2.355
Finnmark	Vannøya nordøst Sandskallen - Sørøya nord	1.439

7 Results

7.1 Offshore wind scenarios

This section presents the results from the simulations of the offshore wind scenarios presented in section 6.1. The wind series initially included in the dataset is utilized for the simulations presented in this section. Section 7.1.1 presents the wind power production in Norway. In section 7.1.2 the area price for selected areas is presented. Section 7.1.3 presents the power transmission in the Norwegian transmission lines. Section 7.1.4 presents data on hydropower production in selected hydro plants, including hydro production for different time scales, ramping and value factors. Moreover, the reservoir level for selected hydro reservoirs is presented in section 7.1.5. Lastly, the social welfare for operating the power system is presented in section 7.1.6.

7.1.1 Wind power production

Figure 10 display the wind power production in Norway throughout the year for scenario Nor30, calculated as the average of all weather years. The figure clearly illustrates the annual variations in wind power production, revealing that wind power production is highest during winter. This observation aligns with the previously presented study conducted by NVE [62], which found that wind power production is highest during winter due to stronger winds.

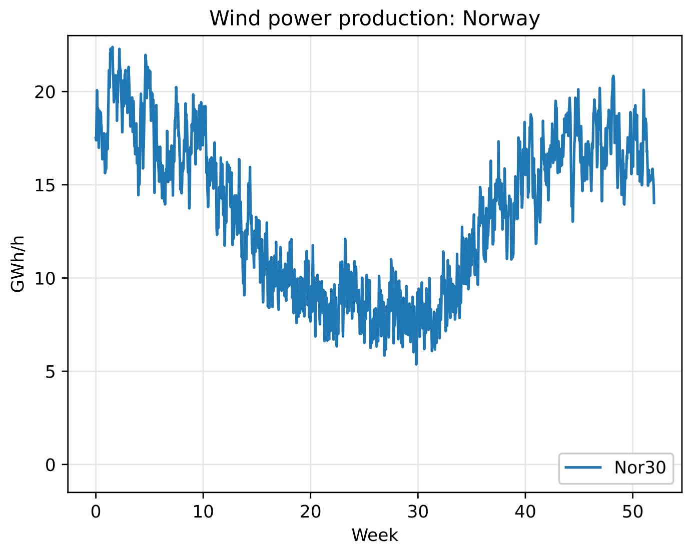


Figure 10: Average annual wind power production in Norway for Nor30

In order to better understand the variation in wind power production across the different scenarios, the total wind power production in Norway is presented for all scenarios in Figure 11. The result is presented as duration curves with values for all weather years. The maximum capacity of each scenario is higher than the specified offshore wind capacity for that particular scenario, as the duration curve includes both onshore and offshore wind power. Since onshore wind power production remains consistent across all scenarios, any differences in power generation among the scenarios can be solely attributed to offshore wind power generation.

As expected, the wind power production is higher in Sor4.5 than Base due to the added offshore wind production. Although Sor30, Mid30, and Nor30 all have offshore wind capacity of 30 GW, there are variations in wind power production among them. This is because the wind series, which represents wind conditions in each area, differ between the areas. As a result, there is varying wind power production depending on the allocation of the wind power capacity in each scenario.

Compared to the other scenarios, Sor30 displays a less even curve with a larger proportion of periods with high wind power production. This is primarily due to the wind power production being concentrated in a smaller area, which leads to longer periods of consistently high or low wind power production, as large shares of the wind farms are affected by similar wind conditions. In contrast, Mid30 and Nor30 experience less frequent periods of maximum wind production in Norway, as the wind farms are distributed across different parts of the country. This reduces the likelihood of all wind farms operating at maximum capacity simultaneously due to weather variations across different parts of the country. The wind power production is higher in Nor30 than in Mid30. This observation suggests that the expanded distribution of wind farms in Nor30 has a favourable impact on wind power production due to better wind conditions.

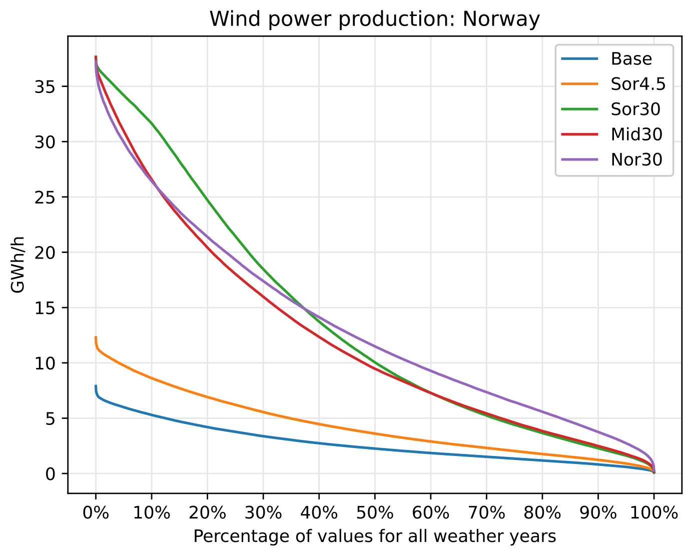


Figure 11: Wind power production in Norway for all scenarios

In Figure 12, the wind power production in Vestsy-OWP during weeks 3-4 in weather year 17 is presented. The wind power production is presented for each load period, which has a time resolution of three hours. The graph provides a detailed illustration of how wind power production varies among different scenarios in the same area. It can be observed that the production pattern is consistent across all scenarios as they are based on the same wind series. However, modifying the wind power capacity in each scenario results in a scaling of the wind power production. The highest wind power production is observed in Sor30, which is the scenario with the largest wind power capacity in Vestsy-OWP.

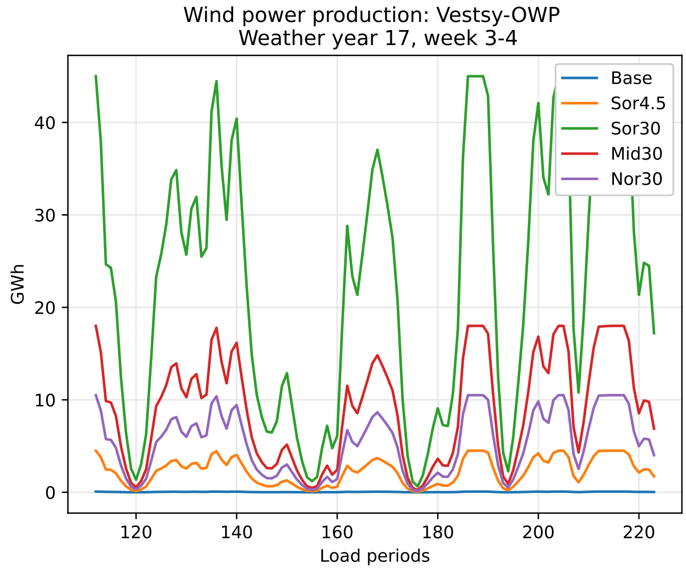
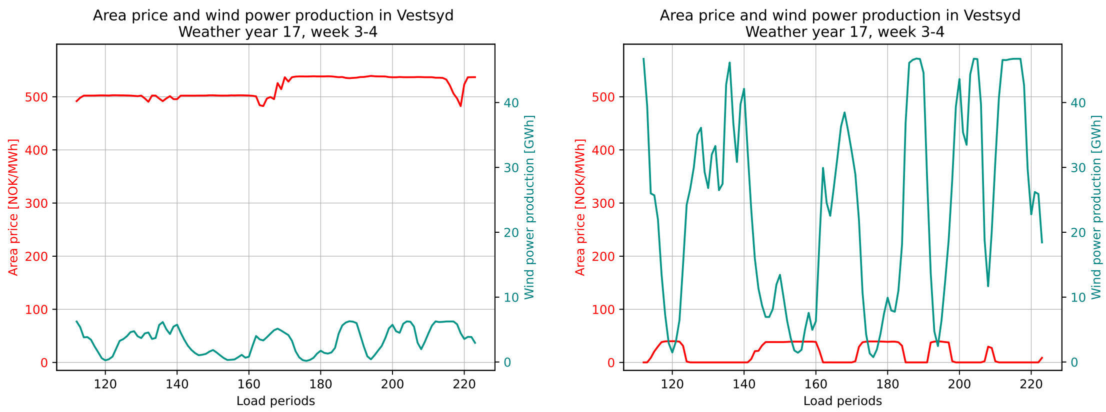


Figure 12: Wind power production in Vestsy-OWP during weeks 3-4 in weather year 17 for all scenarios

7.1.2 Area price

As elaborated in section 3.5.2, previous literature on the impact of wind power on electricity prices has found that due to the marginal price of wind power production being close to zero, the integration of wind power leads to a decrease in electricity prices. In order to verify if these findings hold true for the simulations conducted in this thesis, the wind power production in Vestsy-OWP during the two weeks presented in Figure 12, is further studied. The corresponding area price in Vestsyd for scenarios Sor4.5 and Sor30 is plotted, to analyze the variations in area price based on different levels of wind power production. The result is displayed in Figure 13. Note that the wind power production displayed in this illustration includes the wind power production in both Vestsyd and Vestsy-OWP.



(a) Sor4.5

(b) Sor30

Figure 13: Area price and corresponding wind power production in Vestsyd

The results display that the area price is significantly higher in Sor4.5 compared to Sor30. This finding supports the previously mentioned research on the impact of wind power production on area price. Moreover, the variation in wind production from one load period to the next has a more pronounced effect on the area price in Sor30. In this scenario, the area price is close to zero for periods with high levels of wind power production. The effect of the significant wind production makes the area price in Sor30 generally more variable compared to Sor4.5, which has a more steady area price. For Sor4.5, the amount of wind power is not large enough to change the marginal generator in the system for this period, which is why the price remains unchanged despite varying wind production.

To further validate these observations, the area price is plotted for all weather years in several areas throughout the rest of this section.

Norway

Figure 14-17 present area prices in the areas Sorland, Ostland, Norgemidt and Finnmark for all scenarios. The results are presented as duration curves with values for all weather years. From the results, it is clear that the area price is highest in Base for all areas, followed by Sor4.5. The area prices for the three scenarios with 30 GW offshore wind power production in Norway vary depending on the area. Nevertheless, Sor30 generally results in the highest area prices among these scenarios. The average area price for all areas in Norway for all scenarios is shown in Table 18 in appendix section B.1. The table clearly demonstrates a decline in the average area price in Norway, from 305.11 NOK/MWh in the Base scenario to 20.71 NOK/MWh in the Nor30 scenario.

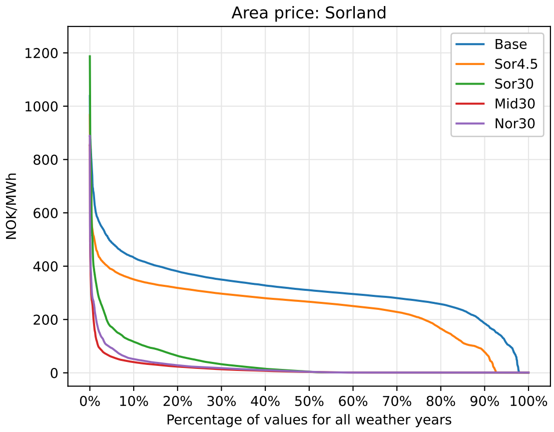


Figure 14: Area price in Sorland

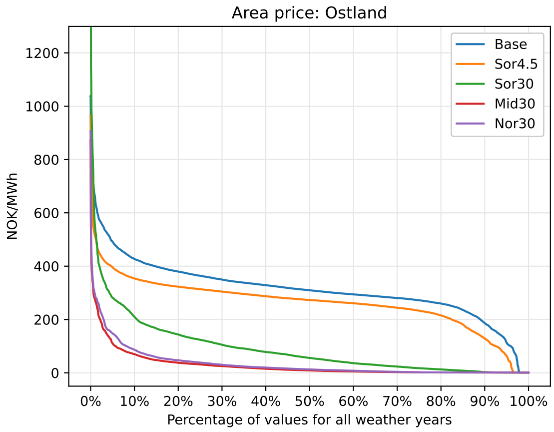


Figure 15: Area price in Ostland

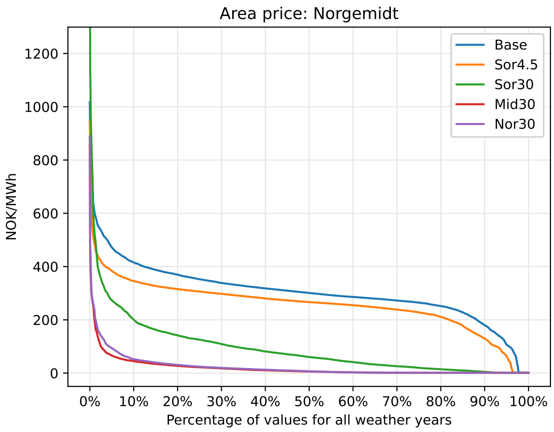


Figure 16: Area price in Norgemidt

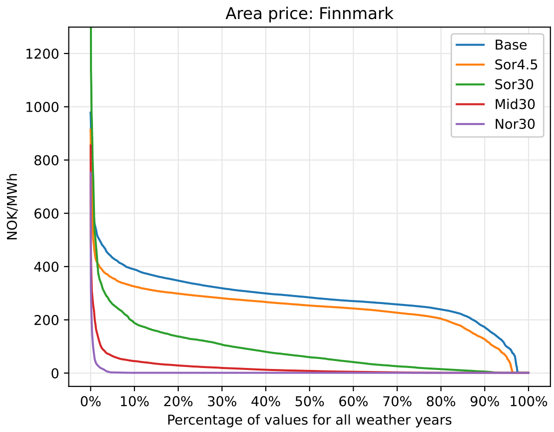


Figure 17: Area price in Finnmark

A general observation is that the power prices in the system decrease as wind power production increases. Among the three scenarios with 30 GW offshore wind, Sor30 generally results in the highest area prices. When studying Sor30 in the four areas, it is evident that Sorland has the lowest area prices for this scenario. This tendency can also be seen in Vestsyd, found in appendix B.1. Each of these two areas has 15 GW wind capacity connected directly to them, which results in a surplus of power and subsequently leads to nearly zero prices during periods of high wind production. Since the combined 30 GW wind power capacity exceeds the demand in these areas, it is desirable to transmit the excess energy to other areas in the system. However, compared to the other 30 GW scenarios, the area price is higher in the remaining regions of Norway for Sor30. When studying the transmission capacity out of the southern areas, displayed in Figure 6, it is evident that this is due to the transmission constraints limiting the flow of high levels of wind power. This result highlights the importance of ensuring adequate transmission capacity when installing large shares of wind power in a smaller area, to enable optimal use of the installed capacity.

Despite the direct connection of 15 GW of offshore wind power, the price in Sorland for Sor30 surpasses that of Mid30 and Nor30 when the price is not close to zero and hence wind production is low. This can be attributed to the concentration of the wind capacity in a smaller area, causing Norway's offshore wind production to rely on the production within that specific region. As a result, the southern areas do not benefit from offshore wind production in other regions during periods of low wind production, leading to higher area prices in these periods. This effect is particularly pronounced due to the correlation in wind production between Sorlan-OWP and Vestsy-OWP, as both areas are located within the same region. As a result, wind production tends to be low in these two areas simultaneously. In contrast, there is minimal to no systematic correlation between wind production among the wind farms in the south and those in central Norway and further north. Consequently, distributing the wind farms results in less variable offshore wind production in Norway, and hence, more stable area prices.

For Mid30 and Nor30, there are small differences between the area prices in Sorland, Ostland, and Norgemidt. However, the differences in area prices are more significant in Finnmark, with substantially lower area prices for Nor30. The same tendency can be seen in Troms and Helgeland, shown in appendix B.1. Nor30 is the only scenario with offshore wind power production further north than Norgemidt. The firm demand in Norway is lowest in the northern part of Norway, as seen in Figure 7. As a result, the large penetration of wind production in these areas creates a power surplus, resulting in extended periods of zero prices. This situation could be eased by transmitting more wind power to the southern parts of Norway, where demand is higher. Nonetheless, the frequent occurrence of zero prices indicates that transmission capacity is constrained.

Europe

This section examines the impact of Norwegian offshore wind power production on power prices in other European countries. Figure 18-21 presents area prices in Sver-midt, Finland, Tysk-nord and GB-mid for all scenarios. The results are presented as duration curves with values for all weather years. The area prices in these areas are generally higher than those observed in Norway. This can mainly be attributed to a greater share of thermal energy production in the energy mix. Some prices even approach the rationing price of 30,000 NOK/MWh. However, these extreme prices are not displayed in the curve presented here, as their inclusion would make it more difficult to see the differences between the various scenarios.

Area prices for Danm-vest and Sver-on1 can be found in appendix B.1.

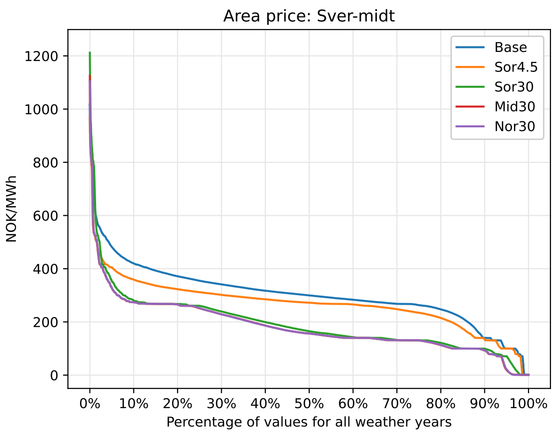


Figure 18: Area price in Sver-midt

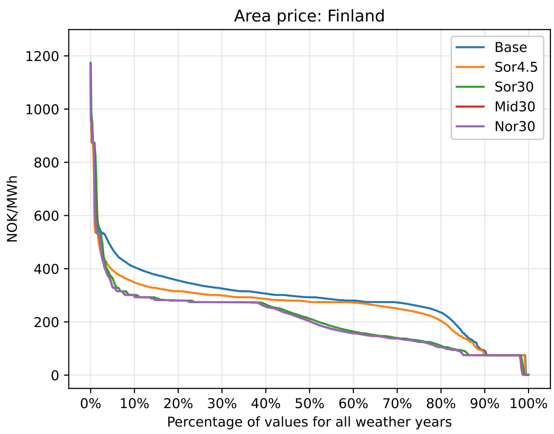


Figure 19: Area price in Finland

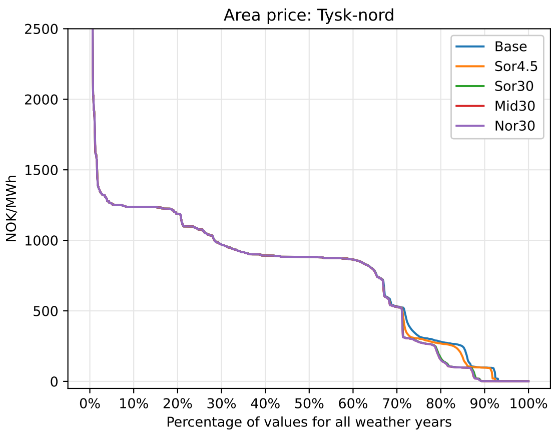


Figure 20: Area price in Tysk-nord

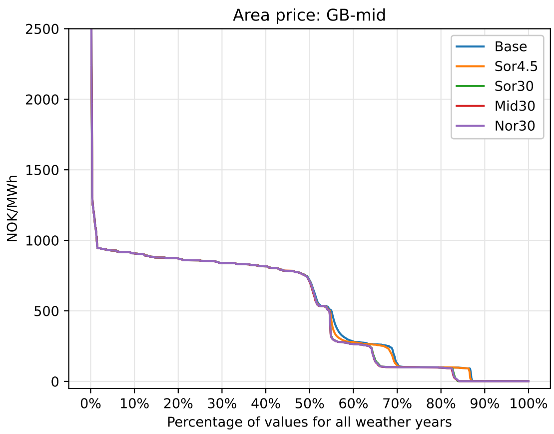


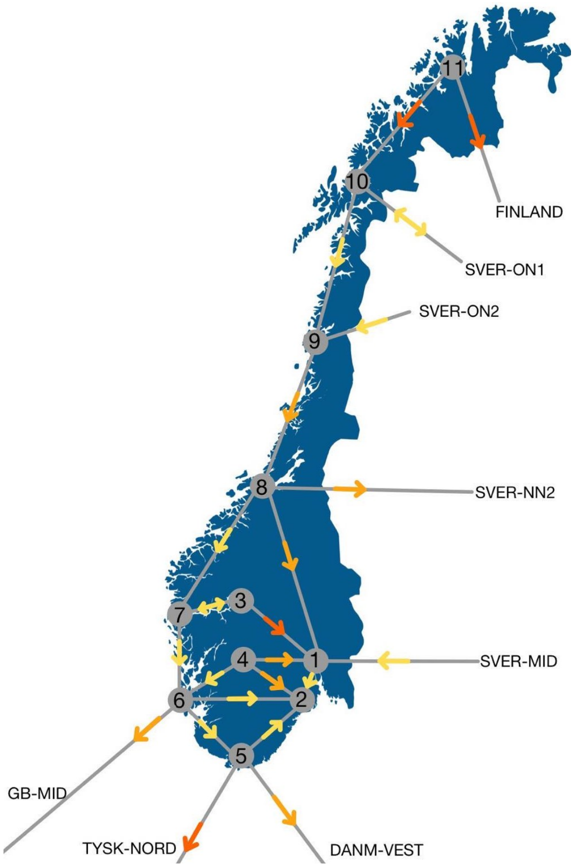
Figure 21: Area price in GB-mid

The Norwegian power system is closely connected to Sweden and this country is therefore particularly impacted by the rise in wind power production in Norway. By analyzing Figure 18, one can observe that as the proportion of offshore wind power production in Norway increases, the area prices in Sver-midt decreases. The installation of 4.5 GW offshore wind power in Norway, represented by scenario Sor4.5, results in a reduction in Sweden's area prices. The effect is even more substantial for the scenarios with 30 GW offshore wind power capacity. The area price in Sor30 is marginally higher than that in Mid30 and Nor30. This is the same trend as observed in the Norwegian areas and is likely attributable to transmission capacity limitations constraining the export from the south of Norway. The difference between the 30 GW capacity scenarios are however not as apparent as in the Norwegian areas. This can be explained by the fact that the transmission capacity from Norway to Sweden is almost fully utilized in all three scenarios, which limits the transmission and makes it difficult to discern potential differences. The area prices in Sver-midt for Mid30 and Nor30 are mostly the same. There are however some differences between the area price in these two scenarios in the north of Sweden, as seen in Sver-on1, shown in Appendix B.1. This is due to the surplus power in the north of Norway resulting in lower area prices in Sver-on1 for the Nor30 scenario. Finland, shown in Figure 19, displays a similar trend as Sver-mid. Nevertheless, the effect of increased wind power production is slightly less pronounced.

Figure 20 and Figure 21 show the area price for Tysk-nord and GB-mid, respectively. The two areas display similar trends in response to offshore wind power production in Norway. While the impact of offshore wind production in Norway is relatively less pronounced in these countries compared to Sweden and Finland, there are still observable effects. Scenario Sor4.5 shows a slight reduction in area prices, but the impact is more notable in the 30 GW scenarios. The differences between the area prices in Sor30, Mid30, and Nor30 are negligible. The effect of Norwegian offshore wind power on power prices is most evident in the low-price part of the duration curve. This can be explained by the fact that lower area prices typically correspond to a larger proportion of renewable energy with zero marginal costs in the energy mix.

7.1.3 Transmission

An illustration of the power transmission in Base is presented in Figure 22. The illustration shows the power exchange in Norway, including both internal connections and cross-border interconnections. The direction of the arrows in each line shows the direction of the average power flow. Bidirectional arrows mean that the transmission in each direction is roughly the same when averaged over the year. The arrows are represented by four different colours to indicate the magnitude of the flow direction. The lightest yellow colour indicates a relatively balanced power exchange, with a majority of power flowing in one direction. The light orange colour indicates a stronger power flow in one direction, with the transmission lines operating at maximum capacity for a significant portion of the time. The orange colour indicates that the power flow is predominantly in one direction, with either maximum capacity utilization occurring in one direction for more than 70% of the time or power exchange being almost exclusively in one direction. Lastly, the darkest red colour (not displayed in Figure 22) indicates that the transmission line operates at maximum capacity in one direction over 90% of the time. The illustration is based on duration curves on power transmission for each transmission line, taking into account values for all weather years. Some of these duration curves are presented in Figure 27-32 which can be found later in this section, while the remaining can be found in appendix B.2. The duration curves provide a more detailed view of the power exchange for each line. Thus, it is recommended to examine them alongside the illustration to gain a more accurate understanding of the power transmission in the system.



Source: Created with MapChart [81]

Figure 22: Power transmission in Norway for Base

The illustration in Figure 22 reveals a market tendency of power exchange from northern Norway to southern Norway. This is particularly evident in Finnmark, where there is a substantial power flow directed towards both Troms and Finland, indicating a power surplus in the area. Another notable observation is the power flow towards Ostland and Sorost. These areas heavily rely on imported electricity as they have high energy demand and limited production capacity. The power flow is especially significant from Hallingdal to Ostland. The cross-border interconnections in Norway indicate a net power export to GB-mid, Tysk-nord, and Danm-vest in the southern region of the country, as well as to Sver-nn2 and Finland in the northern region of the country. Nonetheless, some of the cross-border interconnections demonstrate a more balanced power exchange, and the illustration reveals that the majority of the power flow in the lines from Sver-on2 and Sver-mid is directed towards Norway.

Studying the power flow provides valuable insights into the power system. Thus, it is interesting to investigate the effects of the growing offshore wind power capacity in Norway on the power flows within the system. Figure 23 and Figure 24 present the power transmission in Norway for the scenarios Sor4.5 and Sor30. Both scenarios have offshore wind power production in Vestsy-OWP and Sorland-OWP. Nonetheless, the total capacity installed is 4.5 GW for Sor4.5 and 30 GW for Sor30.

Source: Created with MapChart [81]

Figure 23: Power transmission in Norway for Sor4.5

Figure 24: Power transmission in Norway for Sor30

The power flow in Sor4.5 shares several similarities with Base. There is still a notable north-to-south power exchange, as well as towards the high-demand areas in the south-east of the country. However, increasing the wind capacity to 4.5 GW in the south of the country has an impact on power flows. When studying the cross-border interconnections it can be observed that Norway is now exporting more power to other countries than in the Base scenario. Additionally, power transmission from the western areas of Norway has increased. This is due to the increased power production in the south and southwest.

The impact on the energy system is more significant for the Sor30 scenario, shown in Figure 24. Firstly, the substantial energy production in the south of Norway results in a decrease in power transmission from north to south. Moreover, the lines connecting Sorland and Vestsyd are more often operating at full capacity to export the electricity generated in these areas. As a result, an even greater amount of power is flowing towards Ostland, which in turn transfers more electricity to Sver-midt. With the increase in energy production, Norway's power exports to other countries have risen. The power export is particularly high towards Finland as the line from Finnmark is almost continuously operating at maximum capacity. This can be attributed to the decreased power transmission towards the south of Norway, resulting in a larger surplus of power in the northern region.

The power transmission for Mid30 and Nor30 is illustrated in Figure 25 and Figure 26, respectively. The distribution of 30 GW offshore wind capacity across different regions of Norway has reduced the strain on the power transmission lines outside the southwestern part of the country. Moreover, there is an increased power export to other countries. The main difference between the power flow in Mid30 and Nor30 can be observed in the northern part of Norway. In the Mid30 scenario, 30

GW offshore wind power is concentrated from Midtnorge and further south. The power flow from the northern part of Norway to the southern part is therefore not as significant in this scenario, due to less power demand in the southern areas. In contrast, Nor30 has substantial offshore wind power capacity installed in the northern regions, resulting in an increase in power flow from the north of Norway to the southern regions. Given the significant power production and low energy demand in Helgeland, Troms, and Finnmark, the power flow between these areas is generally balanced. However, there is a notable power flow from Helgeland to Midtnorge, and subsequently to Ostland, through the transmission line connecting them. When studying the illustration of the Nor30 scenario it is evident that distributing offshore wind farms along the whole coast of Norway leads to the same tendencies in power flow as in the Base scenario. Nevertheless, the results from the three scenarios with 30 GW offshore wind capacity in Norway demonstrate that such a significant increase in production capacity puts considerable strain on the transmission system. This is evidenced by many of the interconnections operating at full capacity for extended periods, especially clear for the cross-border interconnections.

Source: Created with MapChart [81]

Figure 25: Power transmission in Norway for Mid30

Figure 26: Power transmission in Norway for Nor30

To provide a more detailed representation of the aspects discussed earlier, the transmission is also displayed in the form of duration curves with values for all weather years. Figure 27 - 32 displays the duration curves for transmission in selected lines. The duration curve for the remaining lines can be found in appendix section B.2.

Figure 27 shows the power transmission in the line connecting Ostland and Hallingdal. When studying the duration curve, it is evident that the line is predominantly used to transfer power from Hallingdal to Osland. Moreover, the transmission increases for more wind power production in the system. Figure 28 presents the power transmission in the line connecting Vestsyd and Vestmidt.

The most notable trend observed is the significant increase in power exchange from Vestsyd to Vestmidt in Sor30, primarily due to the substantial offshore wind production in Vestsyd. As illustrated in the curve, the line operates at full capacity for almost 60% of the time. The duration curve for the remaining scenarios generally shows a relatively balanced power exchange, with some variations observed among the different scenarios.

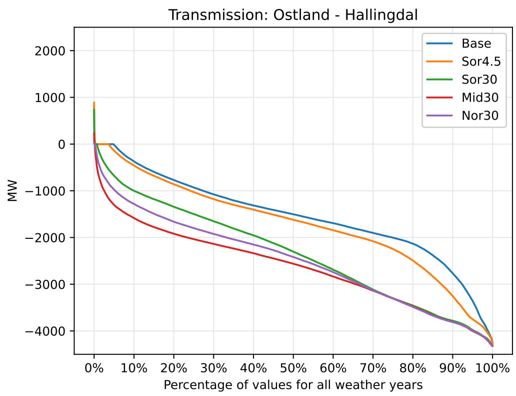


Figure 27: Power transmission from Ostland to Hallingdal

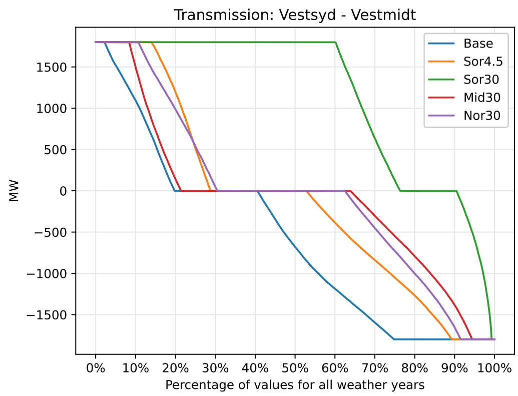


Figure 28: Power transmission from Vestsyd to Vestmidt

In Figure 29, it can be seen that the power exchange between Ostland and Sver-midt changes significantly with an increase in offshore wind power production. In the Base and Sor4.5, the power exchange between the areas is relatively balanced. However, when the offshore wind capacity in Norway reaches 30 GW, the line between the areas is almost continuously operating at full capacity to transfer power from Ostland to Svermidt. The highest transmission is observed in the Mid30 and Nor30 scenarios, where the transmission capacity is reached more than 90% of the time.

The transmission line from Ostland to Norgemidt is shown in Figure 30. In all scenarios, there is a net power flow towards Ostland, however, the magnitude of power flowing towards Ostland varies across the different scenarios. The most significant differences are observed when comparing Sor30 and Nor30. In Sor30, the substantial wind power production in southern Norway results in a lower power flow from Midtnorge to Ostland, as more power is transmitted to Ostland from the southern regions. In contrast, for Nor30, the larger wind power production in the northern part of Norway results in a significant amount of power being transferred from the north to the south. This is reflected in the duration curve where the line operates at maximum capacity 80% of the time.

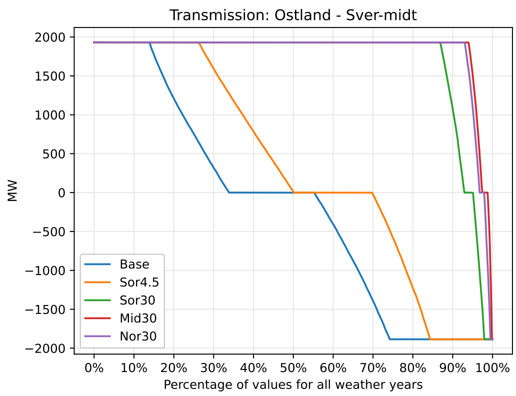


Figure 29: Power transmission from Ostland to Sver-midt

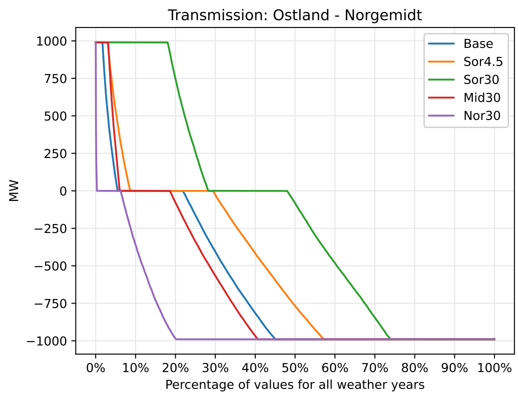


Figure 30: Power transmission from Ostland to Norgemidt

Figure 31 shows the transmission in the line connecting Norgemidt and Helgeland. This line plays a crucial role in the transmission between the northern and southern parts of Norway, making it an important point of study when analyzing power flows between these regions. The duration curve shows a general trend of power flow from north to south in this line, but this trend is less clear for Sor30 and Mid30 due to the significant increase in wind power production in the southern region of Norway in these scenarios. The Nor30 scenario illustrates that the installation of offshore wind power in the northern part of Norway results in a considerable increase in power transmission from the north to the south. The duration curve for this scenario indicates that the line operates at full capacity 60% of the time to transport power from the north to the south.

The duration curve for the transmission line between Troms and Finnmark is presented in Figure 32. It can be observed that in the scenarios Base, Sor4.5, Sor30 and Mid30, the line is primarily used for power transmission from Finnmark to Troms. However, in Nor30, the offshore wind farms in the northern part of Norway generate a power surplus in both areas. As a result, there is less power exchange between the two areas.

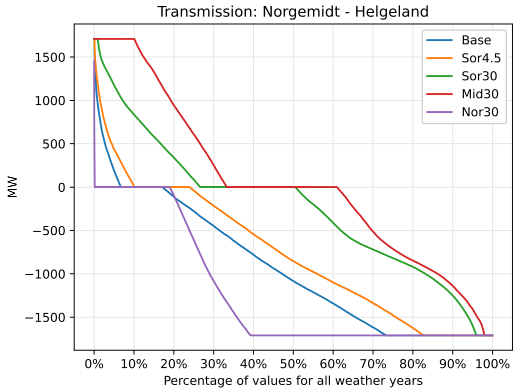


Figure 31: Power transmission from Norgemidt to Helgeland

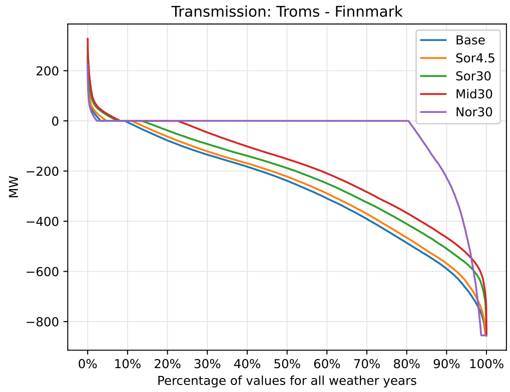


Figure 32: Power transmission from Troms to Finnmark

7.1.4 Hydropower production

In this section, the hydropower production for selected hydropower plants in Norway is analyzed. The objective is to assess the impact of increased wind power production on hydropower production. Four hydropower plants located in different areas of Norway have been chosen for this study, namely Tonstad in Sorland, Kvilldal in Vestsyd, Frøystul in Telemark, and Vessingsjø in Norgemidt. Kvilldal power plant, situated downstream of the Blåsjø reservoir, is the largest power plant in Norway in terms of capacity [87]. Moreover, Tonstad power plant is Norway's largest in terms of production [88]. In comparison, Frøystul and Vessingsjø represent the smaller-scale hydropower plants. All values for production in this section are presented for each load period with a three-hour time resolution.

Figure 33-36 present the hydropower production in Tonstad, Kvildal, Frøystul and Vessingsjø for each scenario. The result is shown as duration curves with values for all weather years. A general observation is that the duration curves representing power production in Tonstad, Kvilldal and Vessingsjø have distinct steps. This phenomenon occurs as a result of the hydro plant's model representation, where the plants are segmented into multiple P-Q curves. The objective of the model is to maximize efficiency within each segment, resulting in the power production being consistently at the most optimal level in every segment. However, Frøystul, located at the uppermost part of the watercourse, is affected by environmental constraints such as minimum water flow requirements. These restrictions prevent the optimization process and limit the ability to achieve the highest efficiency level within each segment. Consequently, the duration curve for hydro production in Frøystul doesn't have the characteristic steps.

To analyze the impact of increased wind power production, the differences between the scenarios are studied. A general trend that can be observed across all four hydropower plants, is that as wind power production increases, the hydropower plants tend to operate more frequently at either maximum capacity or with zero production. Consequently, there is a decrease in production at medium-size capacity for the power plants. This trend is particularly pronounced in Tonstad and Kvildal for the Sor30 scenario. Vessingsjø, located in Norgemidt further north in the country, is most affected by the Nor30 scenario. Frøystul also shows similar tendencies in response to increased wind power production, although the trend is not as evident. This can be attributed to the plant's limited flexibility, due to the environmental constraints previously discussed.

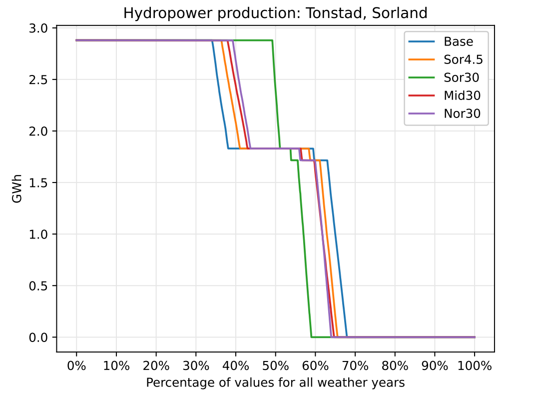


Figure 33: Hydropower production in Tonstad for all scenarios

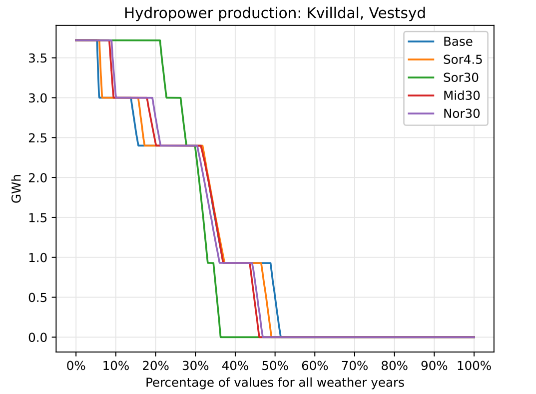


Figure 34: Hydropower production in Kvilldal for all scenarios

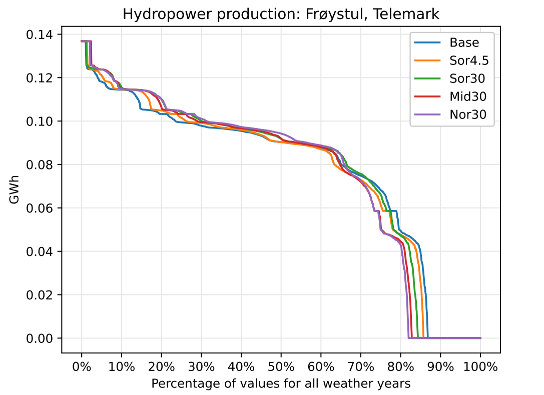


Figure 35: Hydropower production in Frøystul for all scenarios

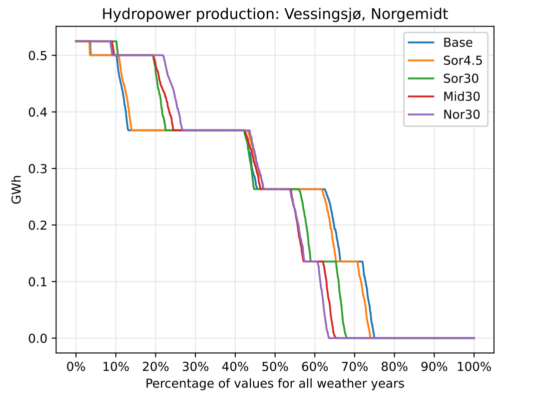
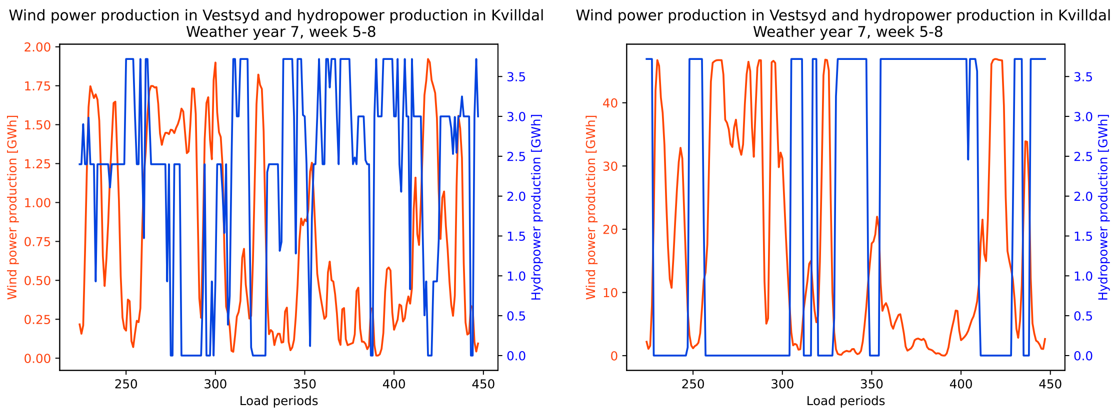


Figure 36: Hydropower production in Vessingsjø for all scenarios

To provide a more detailed analysis of the impact of wind power on hydropower production, the wind power production in Vestsyd and hydropower production in Kvilldal is plotted for week 5-8 in weather year 7. The result is presented in Figure 37 for both Base and Sor30. In this illustration, the wind power production for Vestsyd includes both the onshore area, Vestsyd, and the offshore area, Vestsy-OWP. Nonetheless, the wind power production in Vestsy-OWP is zero for the Base scenario. When analyzing the result, it should be noted that the scaling of wind power production differs for the two plots. Additionally, the hydro production in Kvilldal is not only influenced by the wind power production in Vestsyd. However, the plot still provides a representation of the impact of increased wind power in the system, particularly considering the significant increase in wind power production in the Sor30 scenario.

When examining the correlation between wind power and hydropower in Figure 37, it can be observed that hydro production and wind production complement each other. As wind power production is unregulated, this implies that hydro production adjusts accordingly to wind power production. This phenomenon is particularly evident in the Sor30 scenario, where the hydro plant has zero production during periods of high wind power production but starts producing as wind power production decreases. As the wind power production is significantly lower in Base, the hydropower plant produces more frequently, leading to fewer periods of zero hydro production in this scenario. This results in a higher occurrence of mid-level hydro production in the Base scenario, while the Sor30 scenario experiences more frequent periods of zero hydro production. Furthermore, Sor30 experiences a higher frequency of hydropower production at maximum capacity. This can be attributed to the frequent occurrence of periods with no production, leading the hydropower plant to operate at its maximum capacity during periods with lower wind power generation to prevent spillage. Moreover, the hydro producers increase production in periods of low wind production in order to maintain system stability. These findings align with the results observed when studying the duration curve on hydropower production, confirming that increased wind power integration into the system corresponds to greater occurrences of both maximum and zero production.



(a) Base

(b) Sor30

Figure 37: Wind power production in Vestsyd and hydro production in Kvilldal during week 5-8 in weather year 7

Another observation that can be seen when studying the hydro production in Figure 37 is that the hydropower production displays greater variability in the Base scenario compared to the Sor30 scenario. To investigate if this is a general trend, ramping in hydropower production is plotted for Tonstad, Kvilldal, Frøystul and Vessingsjø in Figure 38-41. Ramping is here defined as the difference in power production between consecutive load periods. For example, if the hydropower production goes from zero to maximum capacity, the ramping is equal to the maximum capacity. Conversely, if the hydropower production remains constant between load periods, the ramping is zero.

The duration curve displaying ramping, confirms the previously made assumption. When studying the occurrence of zero ramping for the scenarios, it is evident that the scenarios with 30 GW offshore wind power production show less frequent ramping compared to the scenarios with lower wind power capacity. Nevertheless, the scenarios with 30 GW offshore wind power production display increased ramping at higher levels of hydro production. This aligns with previous findings, as it was observed a greater occurrence of production at high capacity for these scenarios.

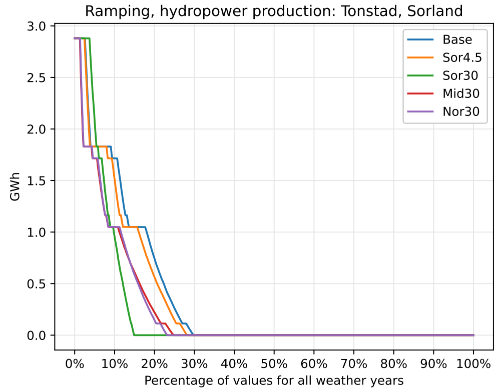


Figure 38: Ramping in hydropower production in Tonstad for all scenarios

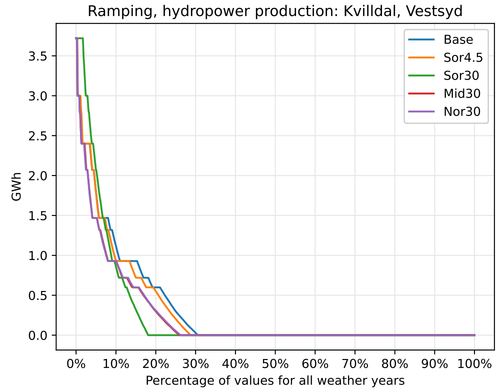


Figure 39: Ramping in hydropower production in Kvilldal for all scenarios

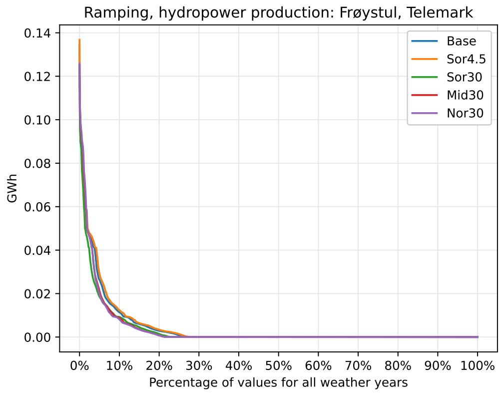


Figure 40: Ramping in hydropower production in Frøystul for all scenarios

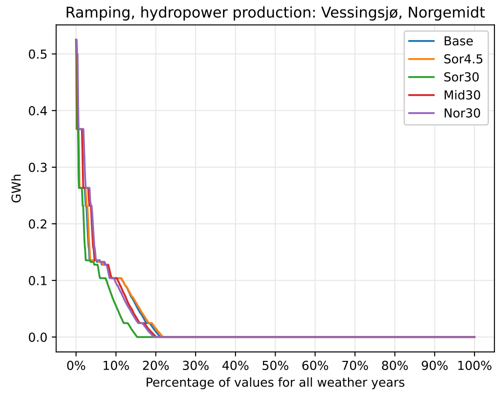


Figure 41: Ramping in hydropower production in Vessingsjø for all scenarios

Value factor

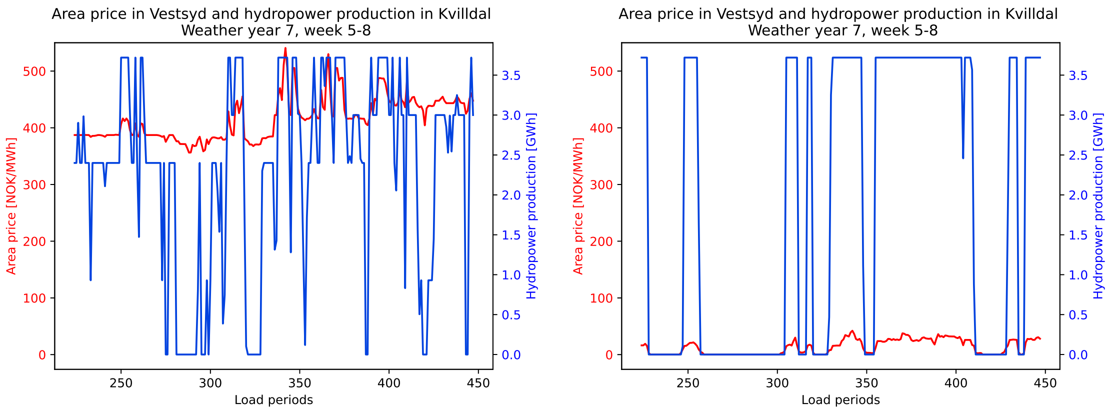
In order to investigate the impact of increased wind power production on the value of hydro production, the value factor, as defined in section 2.3, is calculated. The value factor for Tonstad, Kvilldal, Frøystul, and Vessingsjø is presented in Table 10 for all scenarios. The value factor for the hydro plants is consistently above 1 for all scenarios. A value factor exceeding 1 signifies a flexible power plant, which aligns well with the characteristics of hydropower. Furthermore, the value factor for the hydropower plants increases for more wind power production in the system. Among the scenarios with 30 GW wind power production, the value factor varies depending on the location of the hydropower plant. For Tonstad and Kvilldal, the highest value factor is observed in Sor30, as it is the scenario with the most significant wind power production in Sorland and Vestsyd. Frøystul has the highest value factor in the Mid30 scenario, while Vessingsjø has the highest value factor in the Nor30 scenario.

Table 10: Value factor for Tonstad, Kvilldal, Frøystul and Vessingsjø

	Base	**Sor4.5**	**Sor30**	**Mid30**	**Nor30**
Tonstad, Sorland	1.028	1.077	1.719	1.359	1.407
Kvilldal, Vestsyd	1.070	1.097	2.283	1.761	1.685
Frøystul, Telemark	1.053	1.065	1.100	1.162	1.157
Vessingsjø, Norgemidt	1.084	1.098	1.205	1.438	1.474

A value factor exceeding 1 indicates that the average price captured by a power plant (the "capture price") is higher than the average spot price. The price of electricity production for a power producer is determined by how its production pattern adjusts to the spot price. Therefore, to further study the impact of wind power production on the value factor, one must investigate how hydropower production adapts to the area price in various scenarios. To accomplish this, a detailed study of Kvilldal is conducted. The Sor30 scenario is chosen for this analysis, as it is the scenario that causes the highest value factor in Kvilldal.

Figure 42 illustrates the hydropower production in Kvilldal along with the corresponding area price in Vestsyd during week 5-8 in weather year 7. The result is shown for both Base and Sor30. In Base, the area price generally remains at a higher level compared to Sor30. Furthermore, both scenarios show a tendency where hydropower production adjusts in response to area price, by increasing production during high-price periods. However, as demonstrated earlier, the lower wind power production in Base leads the power plant to operate more frequently at a mid-high level. This makes it more difficult to benefit from the fluctuations in area prices. Additionally, the presence of longer periods with relatively stable area prices, especially clear in Figure 13, poses a challenge for hydro producers to adjust their production to attain prices higher than the average. On the other hand, the area price in Sor30 displays a more pronounced pattern due to the significant wind power capacity, resulting in zero pricing during periods of substantial wind power production. When studying the hydro production in Figure 42b, it is evident that the hydropower producer benefits from these periodic patterns by producing power when the price is higher and stopping production during zero-price periods. Consequently, the opportunity to take advantage of the fluctuating area prices, driven by wind power production, increases the value factor for hydropower. While the value factor is higher for increased wind power production in the system, it is important to note that hydro producers still experience reduced income in these scenarios due to the observed decline in area prices.

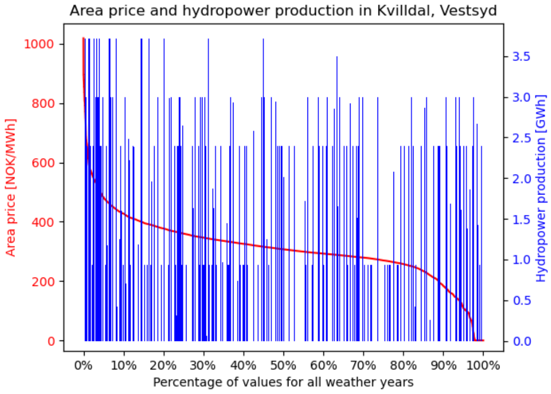


(a) Base

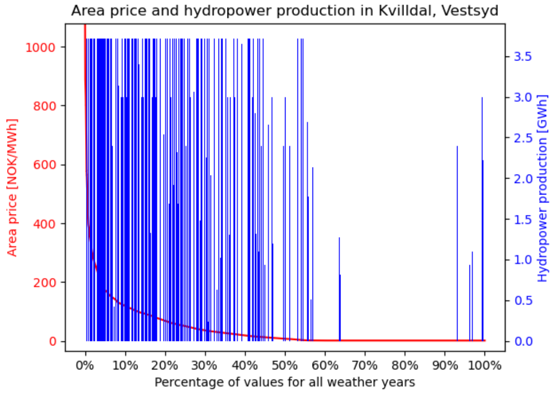
(b) Sor30

Figure 42: Wind power production in Vestsy and hydro production in Kvilldal during week 5-8 in weather year 7

In order to verify that the observed phenomenon holds true in general, the area price and corresponding hydropower production in Kvilldal are presented for all weather years in Figure 43. The figure display the duration curve for the area price in Vestsyd, together with bar charts representing the corresponding hydro production in Kvilldal for each load period. In Base, there is a tendency for increased hydropower production during periods of higher area prices, aligning with the value factor being greater than 1. However, this trend is more pronounced in the Sor30 scenario. In this scenario, Kvilldal demonstrates minimal production during zero-priced periods but has substantial production during periods of higher prices. This observation verifies the explanation regarding the high value factor made previously.



(a) Base



(b) Sor30

Figure 43: Area price in Vestsyd and corresponding hydropower production in Kvilldal

7.1.5 Reservoir level

In this section, the reservoir level for selected hydropower plants will be examined. The study of reservoir trajectories provides useful insight into the operation of hydropower resources, in particular how the reservoir boundaries are approached in depletion (minimum) and filling (maximum) seasons.

The simulations conducted in this thesis utilize 30 weather years. Figure 44 displays the reservoir level in Base for Blåsjø reservoir in Vestsyd, with distinct curves representing each of the 30 weather years. Blåsjø is Norway's largest hydro reservoir with a storage capacity of 3105 mm^3. All curves have the same characteristics due to yearly variations in inflow. The high inflow during late spring, summer and early autumn fills the reservoir, while the reservoirs are emptied during winter due to low inflow and high energy demand. Furthermore, specific characteristics observed in each reservoir can be attributed to environmental constraints affecting the reservoir and its flexibility. Although the reservoir level shown in Figure 44 has consistent characteristics, there are significant differences in reservoir level across the weather years, primarily due to variations in annual inflow. To provide a comprehensive overview of these variations, the reservoir levels presented in this section are displayed as percentiles.

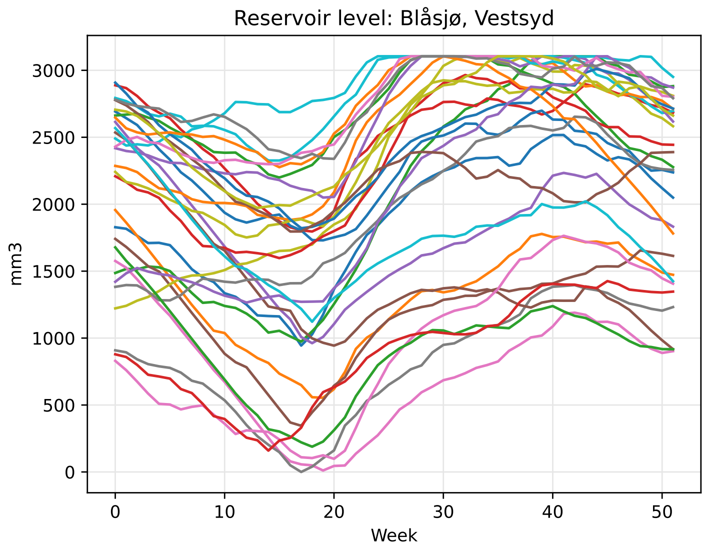


Figure 44: Reservoir level in Blåsjø for all weather years for Base

Figure 45-49 display the reservoir level in Blåsjø for each of the five scenarios. The reservoir level is presented as [0, 25, 50, 75, 100]-percentiles representing all weather years.

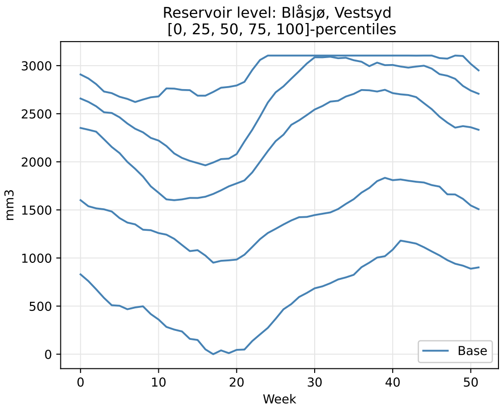


Figure 45: Reservoir level in Blåsjø for Base

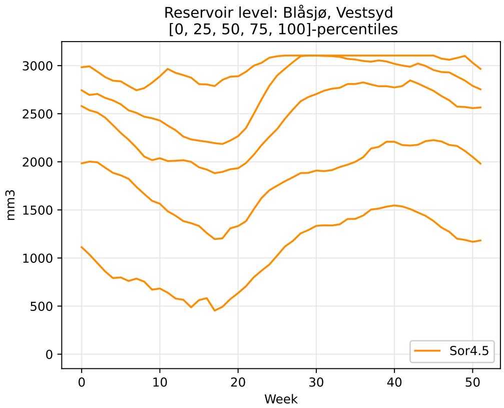


Figure 46: Reservoir level in Blåsjø for Sor4.5

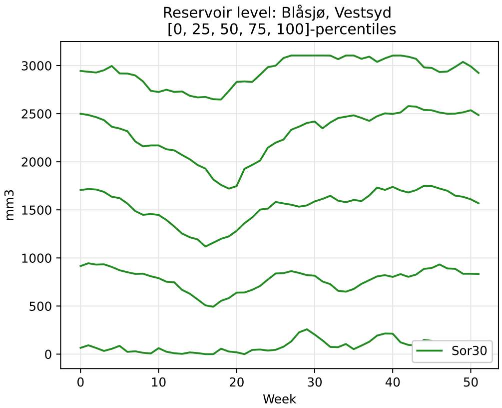


Figure 47: Reservoir level in Blåsjø for Sor30

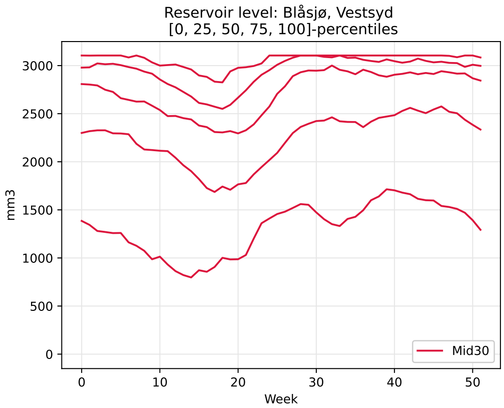


Figure 48: Reservoir level in Blåsjø for Mid30

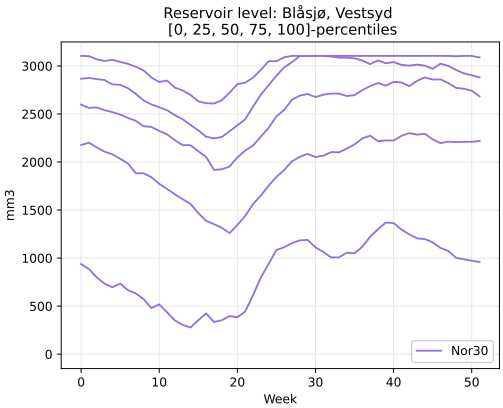


Figure 49: Reservoir level in Blåsjø for Nor30

The percentiles representing reservoir level in Base are evenly distributed, indicating considerable variability in reservoir levels across different weather years. However, upon studying Sor4.5, it becomes evident that the addition of 4.5 GW offshore wind power has led to an increase in the reservoir level in Blåsjø. This implies a decrease in production, which aligns with the lower area price observed in this scenario. The lower price signifies a reduced demand for power production, thereby leading to a higher reservoir level.

When analyzing the reservoir levels in the three scenarios with 30 GW offshore wind capacity, it becomes evident that the distribution of the wind capacity significantly impacts the reservoir level in Blåsjø. In Sor30 the flexibility of the reservoir is exploited to a large extent. While the exploitation of the storage capacity generally indicates good use of a flexible resource, the extreme trajectories indicate risky operation with respect to spillage (100 percentile) and rationing (0 percentile). Both Mid30 and Nor30 display a higher reservoir level compared to Sor30. This aligns with the lower area price observed in these two scenarios in Vestsyd, displayed in Figure 87, resulting in reduced hydro production and consequently higher reservoir levels. Notably, the highest reservoir level is observed in Mid30, which can be attributed to this scenario having the lowest area price in Vestsyd among the three scenarios with 30 GW of offshore wind production. The elevated reservoir level in this scenario is suboptimal since it would be preferable to utilize more of the reservoir's capacity and mitigate the risk of spillage.

Figure 50 and 51 display the reservoir level in Møsvatn and Trollheim for each of the five scenarios. The reservoir level is presented as [0, 50, 100]-percentiles representing all weather years. Møsvatn is the reservoir upstream of Frøystul hydro plant. The characteristic curve observed for Møsvatn is attributed to a minimum restriction on the reservoir level during summer. This restriction results in a rapid increase in reservoir level at the start of the filling season.

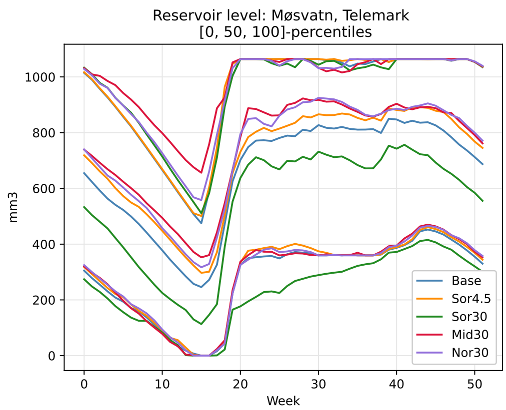


Figure 50: Reservoir level in Møsvatn for all scenarios

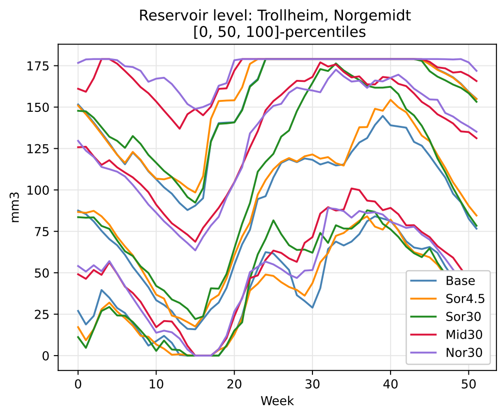


Figure 51: Reservoir level in Trollheim for all scenarios

Similar tendencies to those observed in Blåsjø can also be identified in Møsvatn and Trollheim. Both Møsvatn and Trollheim display the highest reservoir levels for Mid30, slightly above the reservoir level for Nor30. Moreover, in Trollheim, the reservoir level is lowest for Base, followed by Sor4.5 and Sor30. This demonstrates a clear correspondence between the reservoir level in Trollheim and the area prices in Norgemidt. Frøystul displays some similar tendencies, nevertheless, it is Sor30 that leads to the lowest reservoir level.

7.1.6 Social welfare

Table 11 presents the social welfare for the entire system for all scenarios. The table also presents the producer surplus, consumer surplus, the surplus of the transmission system operator (TSO) and the costs of reservoir changes, as social welfare is calculated as the sum of these. The presented values represent the averages across all weather years. Although the result is presented for the entire system, the discussion primarily focuses on the Norwegian system as it is most impacted by the variations in power production for each scenario.

Table 11: Producer surplus, consumer surplus, surplus of TSO, cost of reservoir changes and social welfare for all scenarios

	Producer surplus [Mrd kr]	**Consumer surplus [Mrd kr]**	**Surplus of TSO [Mrd kr]**	**Cost of reservoir changes [Mrd kr]**	**Social welfare [Mrd kr]**
Base	958.09	63 352.89	124.98	-0.40	64 435.56
Sor4.5	936.78	63 375.06	127.54	-0.38	64 439.00
Sor30	868.48	63 435.26	142.02	-1.98	64 443.78
Mid30	854.45	63 448.43	143.65	-1.96	64 444.57
Nor30	855.59	63 447.21	143.72	-1.96	64 444.56

The producer surplus shows a declining trend as more wind power is integrated into the system. This observation aligns with expectations, as greater wind power production leads to a decrease in market prices, as previously observed. Among the scenarios with 30 GW offshore wind capacity in Norway, Sor30 has the highest producer surplus, while Mid30 has the lowest. The substantial producer surplus in Sor30 can be attributed to this scenario having the highest area price among the 30 GW scenarios. Despite the frequent occurrence of zero prices in the north of Norway for Nor30, leading to the lowest producer surplus for this scenario in the northern areas, the total producer surplus is lowest for Mid30. This primarily derives from the lower areas prices in the southern areas for this scenario.

The consumer surplus displays an opposite trend compared to the producer surplus. This is expected since the lower market prices benefit consumers. Consequently, Mid30 has the highest consumer surplus.

The surplus of the transmission system operator is primarily based on congestion rent due to bottlenecks in the transmission system. The scenarios with 30 GW offshore wind result in a higher surplus for the TSO, due to more frequent bottlenecks in the transmission system. Moreover, the surplus is highest for Nor30. This is in line with the previous transmission analysis where the transmission lines are operating at maximum capacity more frequently for this scenario, especially in the northern areas and in the cross-border lines.

The cost of reservoir changes is the valuation of the change in reservoir content from start to finish in the series simulation conducted. The scenarios with 30 GW offshore wind power production stands out with significantly higher costs compared to Base and Sor4.5. Closer inspection shows that the cost has increased especially in GB-North. The Norwegian areas generally have lower costs of reservoir changes for the scenarios with 30 GW offshore wind capacity.

Finally, social welfare is calculated as the sum of producer surplus, consumer surplus, the surplus of the transmission system operator and the costs of reservoir changes. As seen in the values presented, the producer and consumer surplus make up the largest part of social welfare. From the result, it is evident that social welfare increases for more wind power production in the system, mainly due to the increased consumer surplus and surplus of TSO. Mid30 is the scenario with the highest social welfare, slightly above Nor30.

7.2 New wind series

In this section, new wind series generated by SINTEF Energy Research in the spring of 2023 will be analyzed and compared to the wind series initially included in the dataset. As the wind series are derived from external sources and not produced as a part of this master thesis, the analysis will not delve into the reasons behind all the observations in great detail. However, it will provide valuable insights into the impact of the new wind series when compared to the initial wind series. This is essential information to have for further studies to be conducted with the new wind series. Additionally, this analysis will demonstrate the significance of the wind series when conducting case studies on wind power using market modeling.

7.2.1 Wind power production

In order to examine the impact of wind series before any adjustments are made to wind power capacities, the following results are based on the initial dataset described in section 5. Figure 52 displays the total wind power production for the whole system using the initial and the new wind series. The values represent the average hourly production for each three-hour load period and are displayed as duration curves with values for all weather years.

When studying the wind power production in Figure 52, it can be observed that the new wind series result in more wind power production than the initial wind series. This is evident as the wind power production from the new series remains consistently higher than the production for the initial wind series throughout all weather years. Another noteworthy observation is that the maximum production is greater for the new wind series. As both wind series utilize the same dataset with identical conversion factors for wind power production in each area, this implies that there are differences in the maximum values between the two wind series. This is confirmed when analyzing the wind series in detail. The new wind series have a uniform maximum value, specifically 0.955 for onshore areas and 0.89 for offshore areas. Moreover, the initial wind series has a maximum value of 0.925 for onshore areas and 0.89 for offshore areas. The difference in the maximum values in the onshore areas accounts for some of the disparities observed when using the same conversion factor. Additionally, it has been observed that the initial wind series include variations in maximum values for certain areas, deviating from the general maximum value set. As a result, this discrepancy further amplifies the differences between the two wind series in these particular areas.

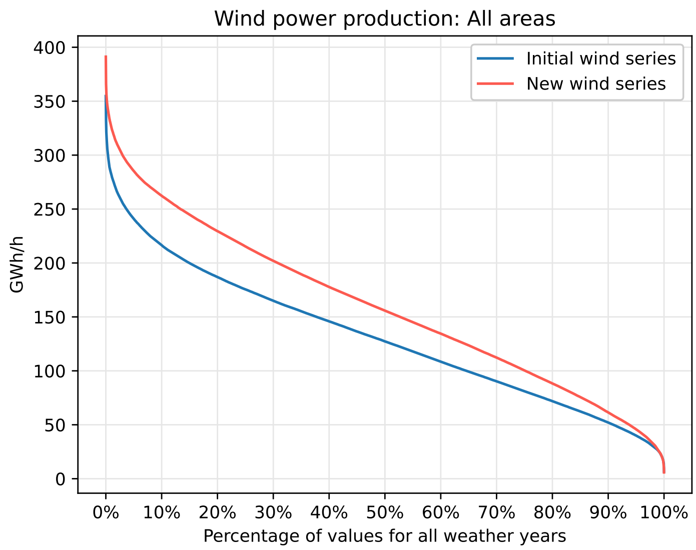


Figure 52: Total wind power production for all areas in the system using the initial and new wind series

To study the difference between the two wind series in further detail, wind power production for individual areas will be studied. Figure 53-58 presents the wind power production for the areas Norgemidt, Troms, Vestsy-OWP, Norgem-OWP, Sver-midt and Tysk-nord using both the initial and the new wind series. The wind power production is presented as the average hourly production for each three-hour load period and is displayed as duration curves with values for all weather years. The results for additional areas can be found in appendix C.1.

When comparing the wind power production resulting from the wind series for the whole system, it was observed that the total wind production increased for the new wind series. However, when examining the wind power production for each specific area, variations arise regarding the impact of the new wind series. The Norwegian onshore areas, in particular, are affected differently by the new wind series. In Figure 53, the wind power production in Norgemidt increases with new wind series. Conversely, in Figure 54 for Troms, the initial wind series results in the highest wind power production. In this area, the initial wind series results in large amounts of wind power production at high levels, while the new wind series displays a more balanced curve with less frequent occurrence of high wind power production. Both Norgemidt and Troms experience a slightly higher maximum wind capacity when using the new wind series.

The wind power production for the remaining Norwegian onshore areas when using the new wind series is displayed in Figure 110 - Figure 116 in appendix section C.1. When analyzing all the Norwegian onshore areas it can be observed that Norgemidt, Telemark, and Ostland are the areas that experience higher wind power production for the new wind series. Sorland, Vestsyd, Helgeland, Finnmark, and Troms have higher wind power production for the initial wind series. It is worth noting that the difference in power production is more pronounced for the areas with higher output for the new wind series compared to those with higher output for the initial wind series. In Vestmidt and Sorost, the wind power production remains the same for both wind series.

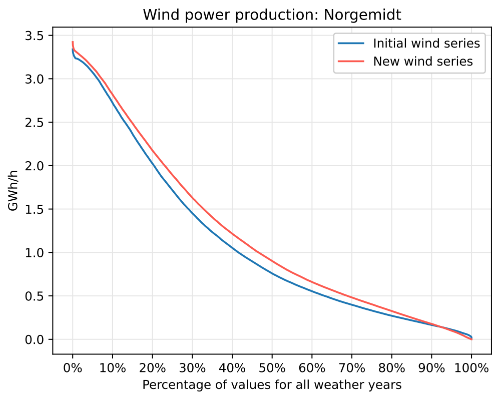


Figure 53: Wind power production in Norgemidt using the initial and new wind series

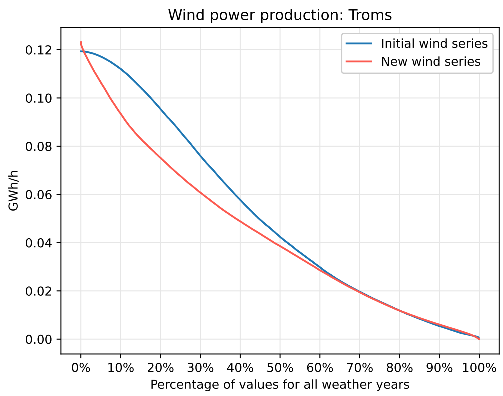


Figure 54: Wind power production in Troms using the initial and new wind series

In contrast to the Norwegian onshore areas, the offshore areas show a more distinct trend. Figure 55 and Figure 56 illustrate the wind power production in Vestsy-OWP and Norgem-OWP, respectively. In these areas, the new wind series results in significantly higher wind power production compared to the initial wind series. Similarly, the same trend can be observed for Sorlan-OWP and Vestsy-OWP shown in section C.1. While the other offshore areas have identical maximum capacities for both wind series, Vestsy-OWP displays a difference between the maximum capacity of the initial wind series and the new wind series. Since both curves are based on the same conversion factor for wind power capacity, this disparity suggests that the wind series have different maximum values. Therefore, to maintain the same maximum wind capacity in Vestsy-OWP for both wind series when scaling the wind power capacity in each scenario, a separate conversion factor must be used for each wind series. In the remaining Norwegian offshore areas, the same conversion factor can be used to scale both wind series to obtain the same wind capacity, as both wind series share the same maximum value.

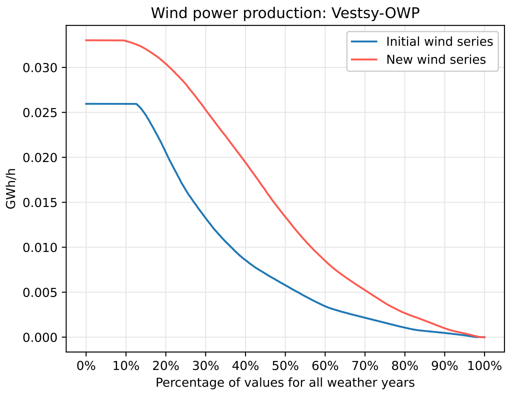


Figure 55: Wind power production in Vestsy-OWP using the initial and new wind series

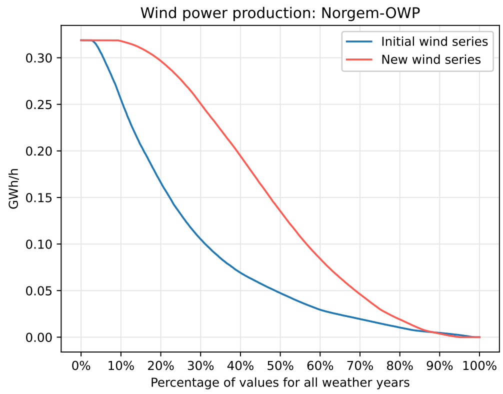


Figure 56: Wind power production in Norgem-OWP using the initial and new wind series

Figure 57 and Figure 58 illustrate the wind power production in Sver-midt and Tysk-nord, respectively. It is evident that the new wind series results in higher wind power production for both areas. This trend is generally observed in the areas outside of Norway, with only a few exceptions.

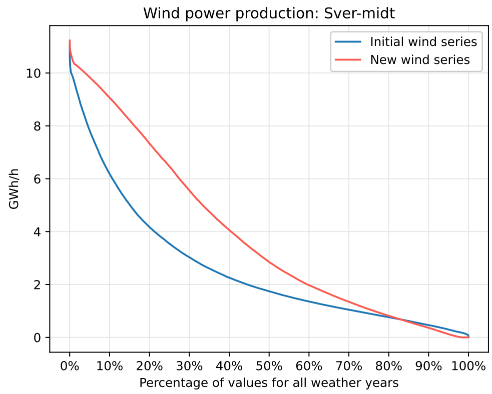


Figure 57: Wind power production in Sver-midt using the initial and new wind series

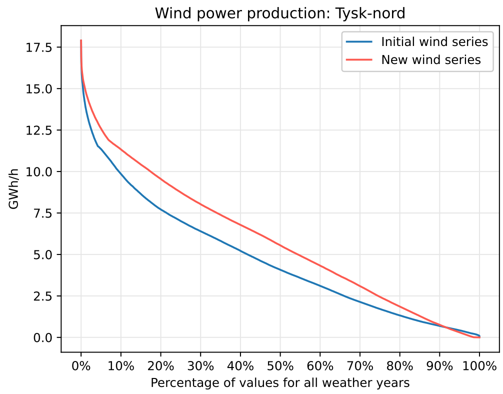


Figure 58: Wind power production in Tysk-nord using the initial and new wind series

After analyzing the wind power production in the system and for selected areas using both the new and initial wind series, the next step is to examine how these findings impact the offshore wind scenarios defined in this thesis. For the case study conducted in this thesis, the wind power production for all areas except the Norwegian offshore areas remains unchanged, and therefore, consistent with those presented earlier. However, for the offshore areas, the wind power capacity is adjusted based on the predefined capacity for each scenario. Although the maximum wind capacity is modified, this only results in a scaling of the wind series, and the relationship between the initial and new wind series remains the same as described earlier.

Figure 59 and Figure 60 display the wind power production in Norway for the scenarios Base and Mid30, utilizing both the initial and new wind series. The values represent the average hourly production for each three-hour load period and are displayed as duration curves with values for all weather years. The scenarios simulated using the new wind series are denoted with "-W". Since Base assumes zero offshore wind power production in Norway, the wind power production in this scenario reflects the onshore areas. The result for Base displays a slight increase in wind power production observed with the new wind series. This finding is in line with the earlier results, as the variations in the impact of the new wind series on the onshore areas result in a relatively small overall difference. However, since the difference in power production is more pronounced for the areas with higher output when using the new wind series compared to those with higher output when using the initial wind series, the total wind power production is slightly higher for the new wind series. The contrast between the initial and new wind series is more noticeable in the Mid30 scenario. The inclusion of offshore wind power production in Norway amplifies the differences between the two wind series in the Mid30 scenario. This is because the new wind series results in significantly higher wind power production than the initial wind series for all Norwegian offshore areas. The average annual wind power production for all areas in Norway for Mid30 is displayed in Table 19 in section C.1. This table reveals that the annual wind power production in Norway has increased from 106.26 TWh in Mid30 to 148.37 TWh in Mid30-W.

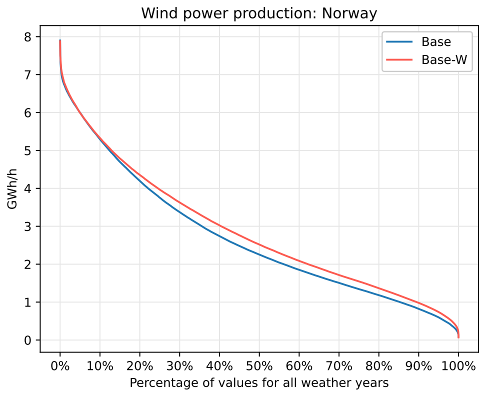


Figure 59: Wind power production in Norway for Base using the initial and new wind series

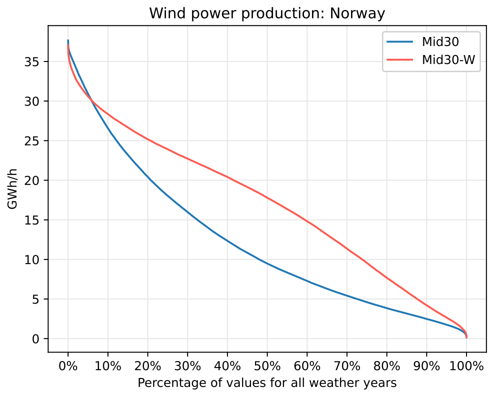
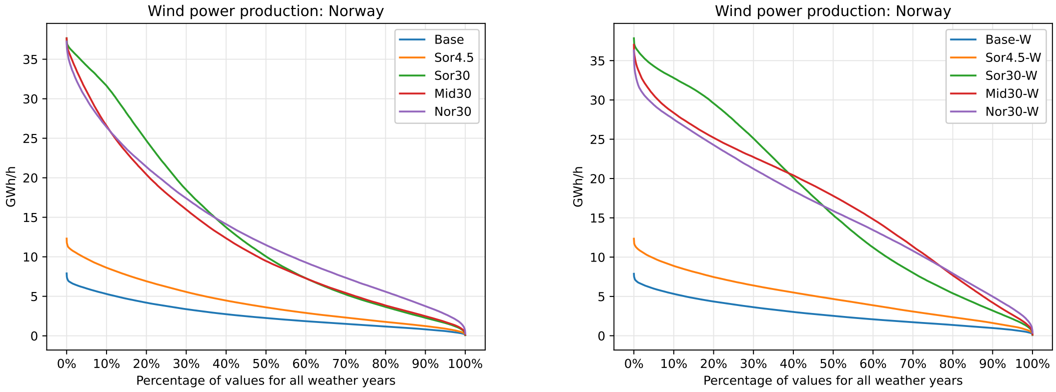


Figure 60: Wind power production in Norway for Mid30 using the initial and new wind series

To examine the impact of the wind series on the scenarios in further detail, the wind power production is shown for each scenario in Figure 61. The scenarios with 30 GW offshore wind power display the most distinct differences between the initial and new wind series. This is expected as the offshore wind areas are the areas with the most pronounced difference between the new and initial wind series as previously shown. It can be observed that Mid30-W and Nor30-W have a more evenly distributed wind power production compared to Mid30 and Nor30, as indicated by the flatter duration curve. This observation suggests that the new wind series effectively captures the impact of distributing wind capacity across different areas, resulting in a more evenly distributed wind power production. When comparing Nor30 and Mid30 using the two wind series, it becomes evident that the initial wind series result in higher wind power production for Nor30, whereas the new wind series results in higher production for Mid30. This difference can be attributed to the fact that in Nor30, the northern offshore wind power production is located in the onshore areas Helgeland, Troms, and Finnmark, which all have lower wind power production for the new wind series as previously stated.



(a) Initial wind series

(b) New wind series

Figure 61: Wind power production in Norway for all scenarios using the initial and new wind series

Figure 62-65 display the wind power production in Finnmark, Sver-midt, Norgem-OWP and Vestsy-OWP during week 10-12 in weather year 16. This is done to obtain a more detailed understanding of the production patterns between the two wind series and identify their differences. The result is plotted for the Mid30 scenario since it includes wind power production in all areas of Norway. Nevertheless, as demonstrated in Figure 12, the production patterns remain consistent across all scenarios, as they are based on the same wind series. Modifying the wind power capacity in each scenario only scales the magnitude of wind power production. Note that the wind power production is shown for each load period with a three-hour time resolution.

When comparing the wind power production between the wind series in the selected time frame, a notable observation is that despite some significant differences, it can be observed certain similar characteristics. This is particularly evident in Finnmark, shown in Figure 62, where there is a similarity in the production patterns across both wind series. However, in the specific weeks illustrated, the wind power production appears to be less variable for the new wind series compared to the initial series. In Sver-midt, shown in Figure 63, the wind production resulting from the initial and new wind series demonstrates fewer similarities for the displayed weeks.

Figure 64 and Figure 65 display wind power production in the Norwegian offshore areas Norgem-OWP and Vestsy-OWP, respectively. Norgem-OWP shows significant disparities between the initial and new wind series, with the new wind series displaying larger variations and higher occurrences of maximum production compared to the initial wind series. In Vestsyd-OWP, there is a stronger correlation between wind power production in the initial and new wind series. However, the new wind series shows a more variable production pattern compared to the initial wind series.

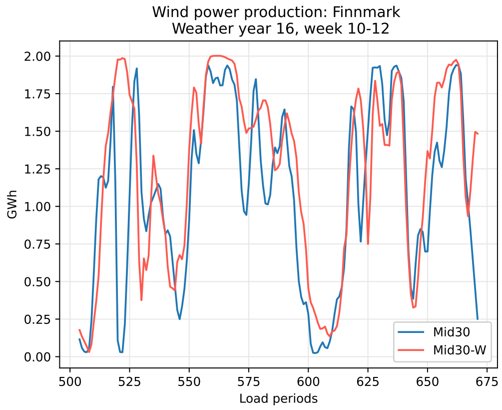


Figure 62: Wind power production in Finnmark during weeks 10-12 in weather year 16 using the initial and new wind series

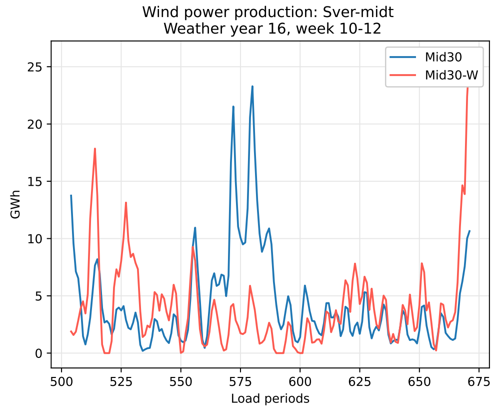


Figure 63: Wind power production in Sver-midt during weeks 10-12 in weather year 16 using the initial and new wind series

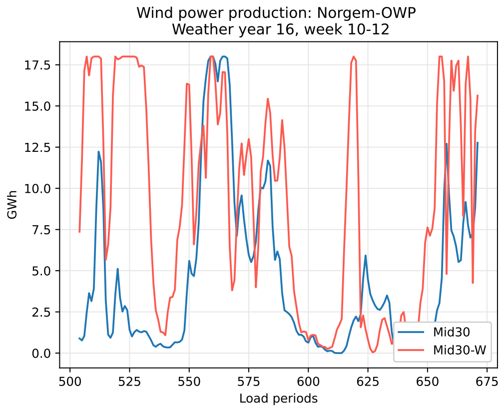


Figure 64: Wind power production in Norgem-OWP during weeks 10-12 in weather year 16 using the initial and new wind series

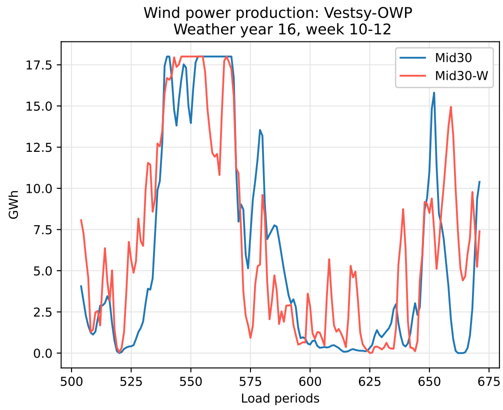


Figure 65: Wind power production in Vestsy-OWP during weeks 10-12 in weather year 16 using the initial and new wind series

When analyzing the production patterns of both wind series during the selected three-weeks period, it was challenging to identify any consistent trends across all areas. However, since the illustration only encompassed three weeks, it does not provide a comprehensive overview of the variations in production for the two wind series. Therefore, the ramping in wind power production is plotted for the four areas in Figure 66-69. Ramping is here defined as the difference in power production between consecutive load periods.

The result on ramping reveals that the observations made for the four areas during the two-week period hold true for the entire time period. In Finnmark, the initial wind series displays a slightly higher ramping, which corresponds to the lower variability observed in wind power production for the new wind series during the three-week period. In contrast, Sver-midt displays a slightly higher ramping for the new wind series. Lastly, both Norgem-OWP and Vestsy-OWP display increased ramping for the new wind series, with Norgem-OWP showing the most pronounced difference. These findings further support the observations from the three-week period. Figure 120-122 in appendix C.1 demonstrates that this trend is consistent for all the Norwegian offshore areas. For the remaining areas in the system, there is no clear tendency when comparing the ramping between the initial and new wind series. Nonetheless, it is worth noting that a majority of the areas show higher ramping when using the new wind series.

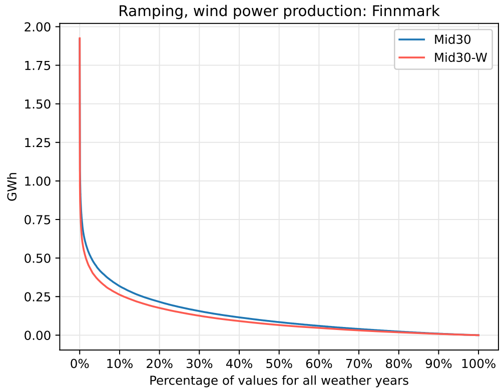


Figure 66: Ramping in wind power production in Finnmark using the initial and new wind series

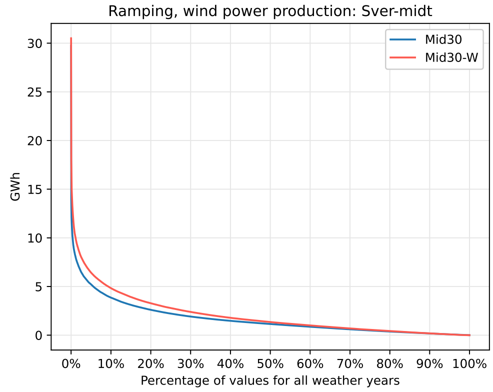


Figure 67: Ramping in wind power production in Sver-midt using the initial and new wind series

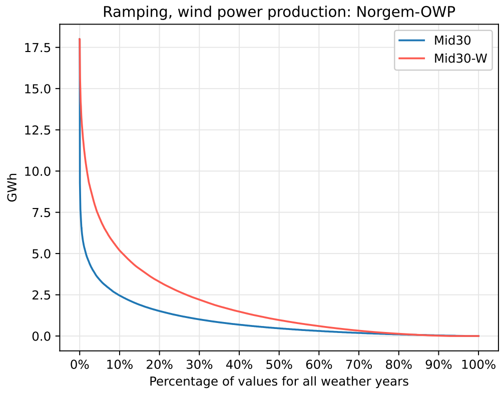


Figure 68: Ramping in wind power production in Norgem-OWP using the initial and new wind series

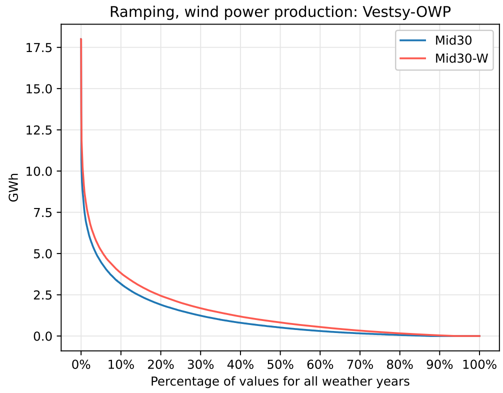
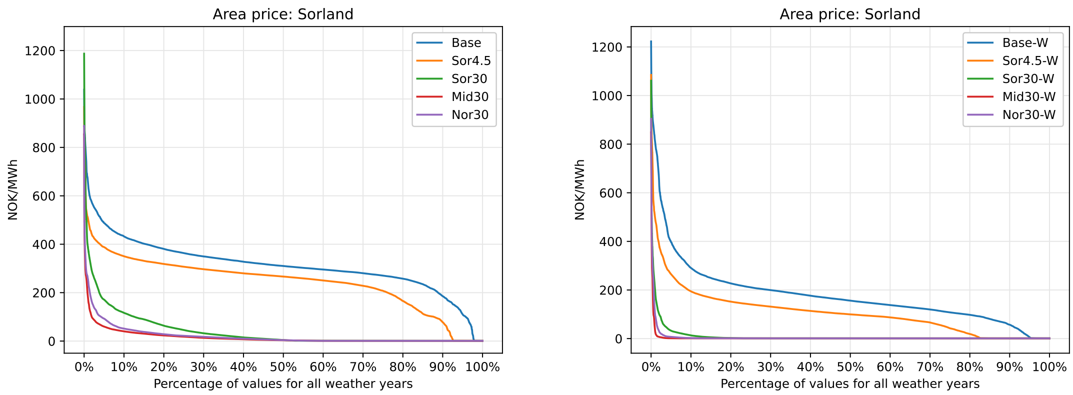


Figure 69: Ramping in wind power production in Vestsy-OWP using the initial and new wind series

7.2.2 Area price

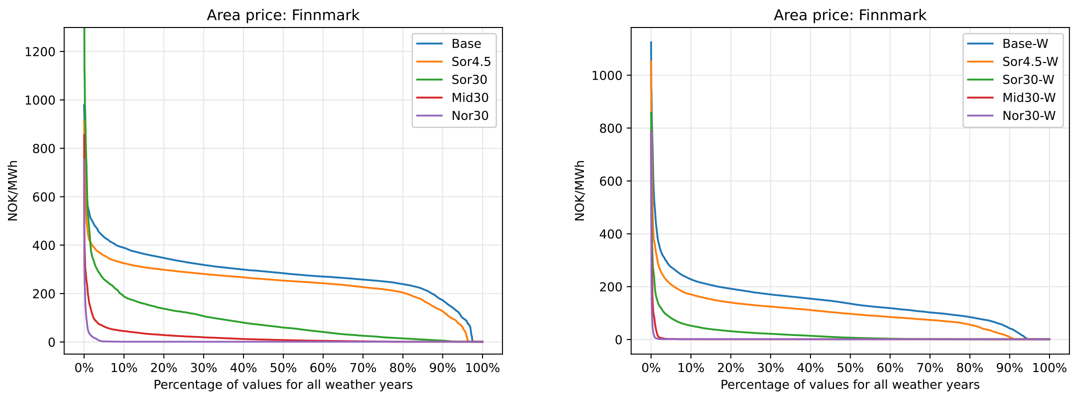
To further examine the impact of the new wind series, a comparison of the area prices for the two wind series is presented in Figure 70-72. These figures illustrate the area prices for the areas Sorland, Finnmark, and Sver-midt. The area prices when utilizing the new wind series are presented as duration curves for additional areas in Appendix C.2. Moreover, the average area price for all areas in Norway for all scenarios is shown in Table 20 in appendix section C.2. When comparing the area prices between the initial and new wind series, it becomes evident that the new wind series result in significantly lower area prices for all areas and all scenarios. This observation is in line with expectations, as it has been observed that an increase in wind power production leads to a decrease in area prices. Since the new wind series results in even greater wind power production, as previously shown, this further contributes to the reduction in area prices. Table 20 shows that Mid30-W results in the lowest area price in Norway, with an average area price of 5.93 NOK/MWh.

When studying the area price in Sorland and Finnmark, it can be observed that the scenarios with 30 GW offshore wind power in Norway lead to a significant occurrence of prices close to zero for the new wind series. As demonstrated earlier, there exists a substantial disparity in wind power production between the initial and new wind series specifically in the offshore areas. This directly contributes to the divergence in area prices between the two wind series in the scenarios that include offshore wind in Norway. Nevertheless, despite the relatively small difference in wind production in Norway between the two wind series in the Base scenario, the area price in Norway is demonstrating a significant reduction for the new wind series in this scenario. This is attributed to the increased wind power generation in the rest of the system, which subsequently impacts Norwegian power prices. This tendency demonstrates how Norway is affected by the power prices in other countries.



(a) Initial wind series (b) New wind series

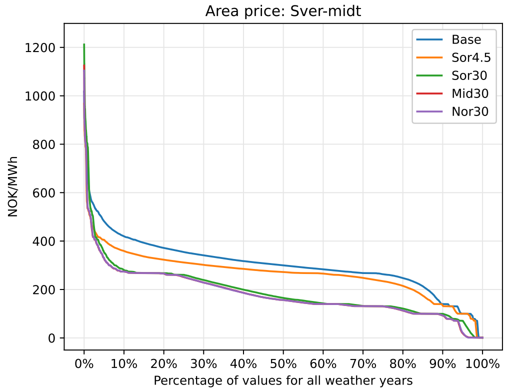
Figure 70: Area price in Sorland for all scenarios using the initial and new wind series



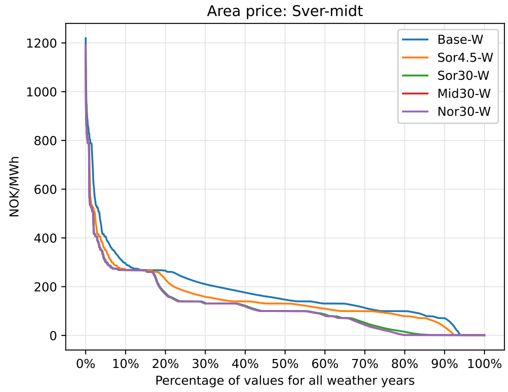
(a) Initial wind series (b) New wind series

Figure 71: Area price in Finnmark for all scenarios using the initial and new wind series

As displayed in Figure 72, the area price in Sver-midt decreases for all scenarios when using the new wind series. The scenarios involving 30 GW offshore wind in Norway experience a decrease in area prices and a greater occurrence of prices close to zero. However, the reduction in area prices is more pronounced for Base and Sor4.5, resulting in a narrower gap between the area prices in these scenarios and the scenarios with 30 GW offshore wind. This observation might be attributed to the fact that in the scenarios with 30 GW offshore wind power, Sver-midt is already greatly impacted by the increased wind power production in Norway. The transmission lines connecting Norway and Sweden operate near maximum capacity, ensuring continuous transfer of power from Norway to Sweden. As a result, the increased offshore wind power production in Norway for the new wind series has a relatively lesser effect on Sweden since the transmission lines already has reached maximum capacity.



(a) Initial wind series



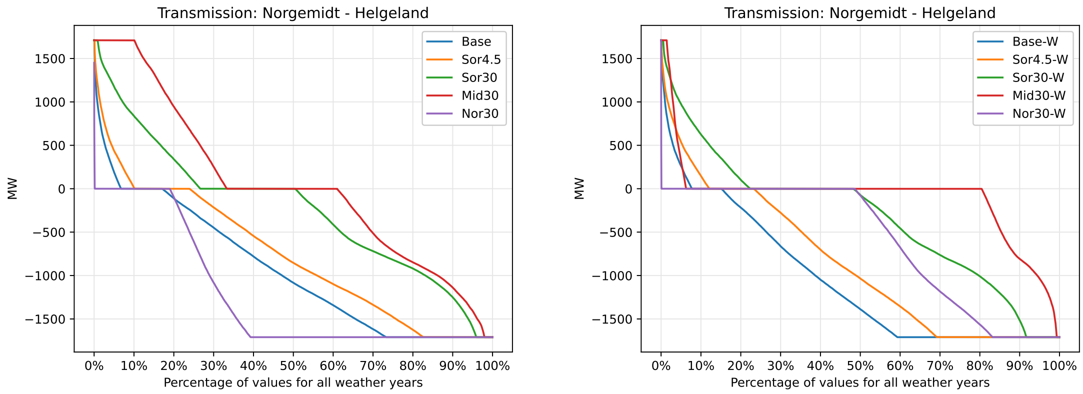
(b) New wind series

Figure 72: Area price in Sver-midt for all scenarios using the initial and new wind series

7.2.3 Transmission

The observed impact of the new wind series on both wind power production and area prices implies that the new wind series also influence the power flow within the system. This section aims to describe some of the observed trends by focusing on three specific transmission lines, shown in Figures 73 to 75. The power transmission resulting from the new wind series is presented for additional transmission lines in Appendix C.3. In general, the overall tendencies observed in the previous analysis of power flow remain consistent. However, the introduction of additional wind production through the new wind series has some impact on power transmission. One notable effect for the scenarios with 30 GW offshore wind power in Norway is the increased occurrence of zero transmission, indicating identical area prices in the areas connected by the transmission line. This tendency can be attributed to the frequent instances of prices close to zero in these scenarios for the new wind series.

Figure 73 shows the power transmission from Norgemidt to Helgeland using the initial and new wind series. In this transmission line, both Base-W and Sor4.5-W show an increased power flow from Helgeland to Norgemidt compared to Base and Sor4.5. This observation might appear somewhat unexpected, considering the reduced wind power production in the northern areas Helgeland, Troms, and Finnmark when applying the new wind series. However, upon examining the cross-border transmission lines connecting these areas, presented in Appendix C.3, it becomes evident that the power transmission from Finland and Sweden to these northern areas has increased. This results in increased power flow from the northern to the southern part of Norway. A marginal rise in power flow from Helgeland to Norgemidt can also be observed in the Sor30-W scenario. Furthermore, Mid30-W and Nor30-W have an increase in zero transmission occurrences. This is due to the significant occurrences of prices close to zero in the Norwegian areas for these scenarios. This effect is particularly evident in Mid30-W, where the increased offshore wind production in the south of Norway limits the demand for power transfer from the northern areas. In Nor30-W, the impact is less pronounced since the offshore wind power production in this scenario is distributed throughout the entire coast of Norway, increasing the power surplus in the northern part of Norway.

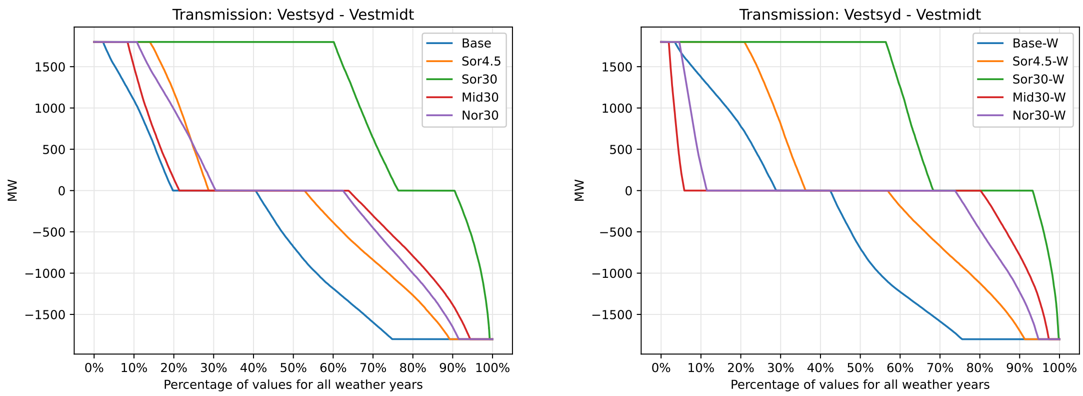


(a) Initial wind series

(b) New wind series

Figure 73: Power transmission from Norgemidt to Helgeland using the initial and new wind series

Figure 74 illustrates the power transmission from Vestsyd to Vestmidt for both the initial wind series and the new wind series. In Base, the transmission towards Vestmidt is slightly higher for the new wind series compared to the initial one. Sor4.5-W also demonstrates a minor increase in power transmission from Vestsyd to Vestmidt. As previously shown, Vestsyd has lower wind power production for the new wind series. However, the increased power flow from Vestsyd may be attributed to the decrease in power transfer to other countries from the southern areas of Norway, as shown in Appendix C.3, due to increased power production in continental Europe when using the new wind series. In Sor30-W, there is an increase in zero transmission between Vestsyd and Vestmidt compared to Sor30. Nonetheless, both Mid30-W and Nor30-W have a more substantial rise in zero transmission. This is expected as these scenarios also result in more prices close to zero as previously shown.

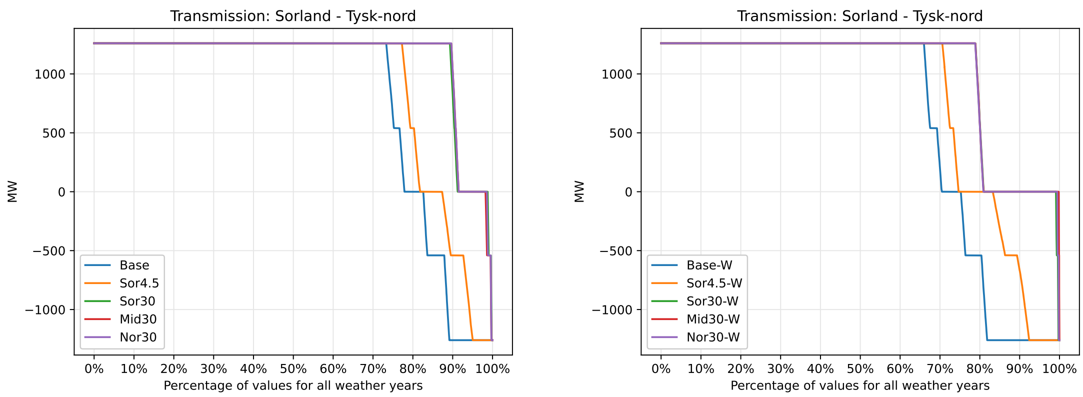


(a) Initial wind series

(b) New wind series

Figure 74: Power transmission from Vestsyd to Vestmidt using the initial and new wind series

Figure 75 displays the power transmission from Sorland to Tysk-nord using the initial and new wind series. In this transmission line, there is a reduction in power transfer from Sorland to Tysk-nord across all scenarios for the new wind series. This can be attributed to the increase in wind power production in Tysk-nord when using the new wind series, which results in a reduced reliance on imports from Norway. In Base-W, there is an increase in power transfer from Tysk-nord to Sorland. However, for the scenarios with more offshore wind power production in Norway, the decrease in power transmission from Sorland is replaced with an extended duration of zero transmission due to the substantial power production in both areas.



(a) Initial wind series

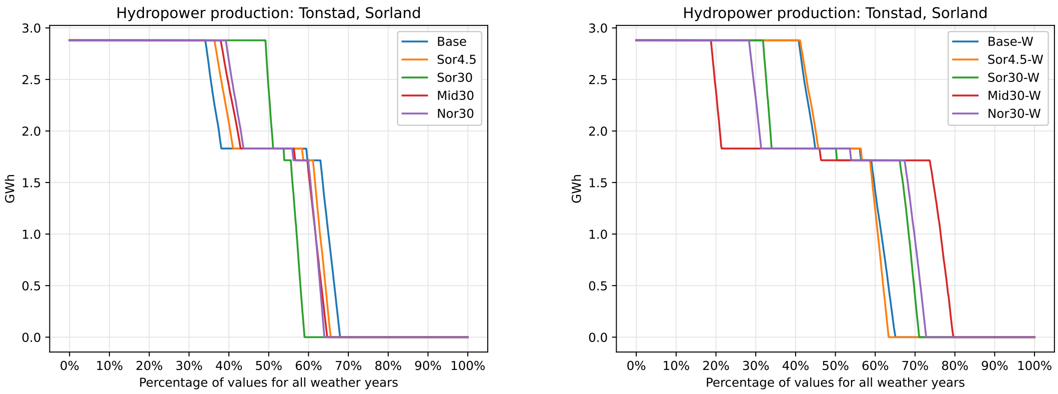
(b) New wind series

Figure 75: Power transmission from Sorland to Tysk-nord using the initial and new wind series

7.2.4 Hydropower production

The hydropower production in Tonstad and Vessingsjø using the initial and new wind series is illustrated in Figure 76 and Figure 77, respectively. Despite being based on the same scenarios, the utilization of different sets of wind series results in significant disparities when comparing the hydro production in the hydropower plants for each scenario. In Section 7.1.4, the analysis of the hydropower production for the initial wind series concluded that the hydropower plants tend to operate more frequently at either maximum capacity or with zero production as the wind power production increased. When examining the hydro production in Tonstad for the new wind series, it can be observed that the higher wind production resulting from the new wind series causes Base-W and Sor4.5-W to operate more frequently at maximum or zero capacity. This observation aligns with the pattern observed when using the initial wind series. However, for the scenarios involving 30 GW offshore wind capacity, the hydro plant operates more at mid-level production and less at maximum and zero production. This trend is most pronounced for Mid30-W, followed by Nor30-W and Sor30-W, respectively. Consequently, the hydropower production in Tonstad displays a tendency where scenarios with low offshore wind capacity operate more often at maximum and zero production, while scenarios with 30 GW offshore wind capacity tend to operate more frequently at mid-level production. This trend contradicts the observations made with the initial wind series. Vessingsjø follows a similar trend to Tonstad, where Mid30-W and Nor30-W show a higher frequency of mid-size production. However, Sor30-W deviates from the other 30 GW scenarios by showing an increased frequency of both maximum and zero production, alongside Base-W and Sor4.5-W.

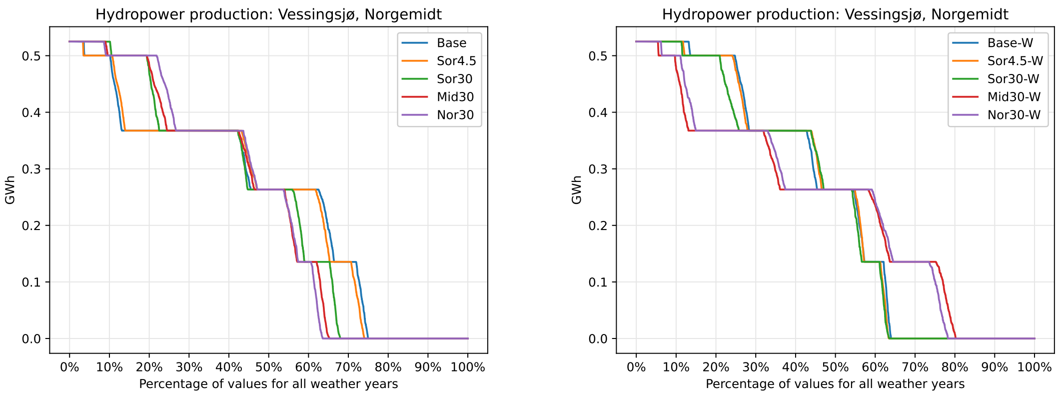
The hydro production in Kvilldal and Frøystul when using the new wind series is shown in Appendix C.4. These results further confirm the consistency of the observed pattern in hydro production when using the new wind series.



(a) Initial wind series

(b) New wind series

Figure 76: Hydropower production in Tonstad for all scenarios using the initial and new wind series

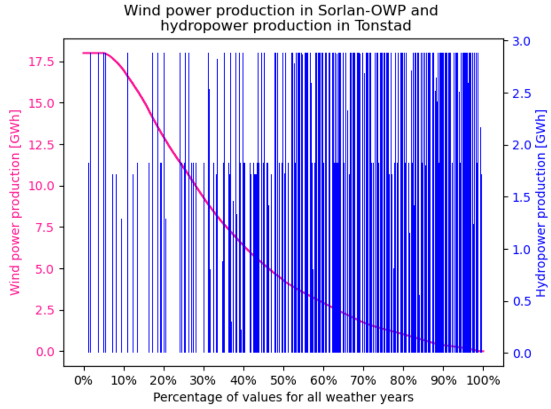


(a) Initial wind series

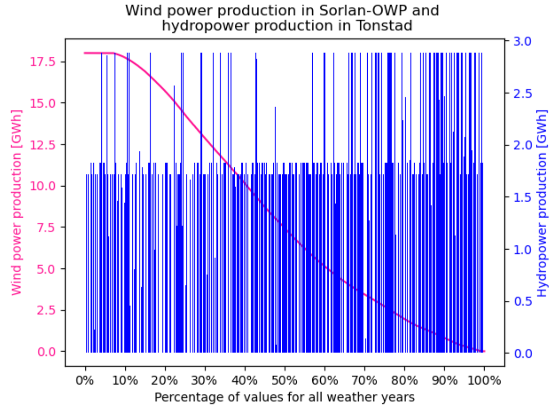
(b) New wind series

Figure 77: Hydropower production in Vessingsjø for all scenarios using the initial and new wind series

As discussed earlier, there are notable differences between the observed hydro production when using the initial and new wind series. In order to explain this observation, further analysis is conducted on the Mid30 scenario in Tonstad, which displays significant discrepancies between the two wind series. Figure 78 illustrates the wind power production in Sorlan-OWP for both wind series, along with the corresponding hydro production in Tonstad. As shown in Figure 118, the wind power production in Sorlan-OWP consistently remains at a higher level for the new wind series. For both wind series, the hydropower production adjusts to the wind power production by generating more power during periods of low wind power production. However, when considering the initial wind series, there is a higher frequency of hydro production reaching maximum capacity, whereas the new wind series results in more production at intermediate levels.



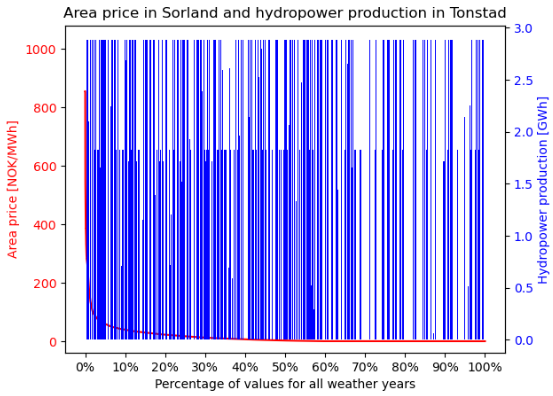
(a) Initial wind series



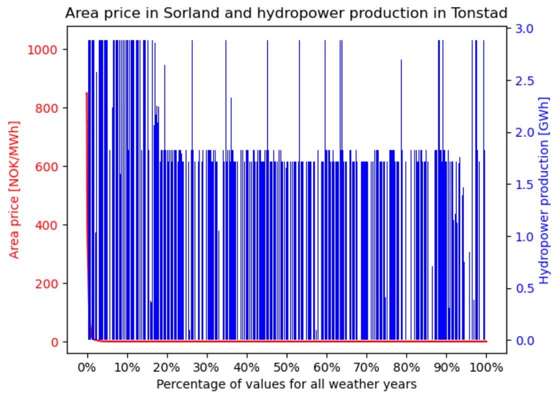
(b) New wind series

Figure 78: Wind power production in Sorlan-OWP and corresponding hydropower production in Tonstad for Mid30 using the new and initial wind series

The changes in hydropower production in Tonstad can be explained by studying the corresponding area prices. Figure 79 display the area price in Sorland for the two wind series along with the corresponding hydro production in Tonstad. Both illustrations show tendencies of hydro producers to adjust their output by increasing production when the area price is high and reducing production when the area price is low. As demonstrated earlier, the area price for the new wind series displays fewer occurrences of high prices. This indicates fewer instances of large variations in wind power production, reflecting favourable conditions in the power system. Consequently, there is less need for hydro producers to regulate power in order to maintain system stability. Hence, the hydro producers aim to operate at a level that maximizes efficiency, allowing them to generate the most energy from the available water resources. For Tonstad, the best efficiency is obtained at the mid-level capacity clearly shown in Figure 79 for the new wind series. In contrast, the initial wind series reveal larger variations in area prices, which leads to a higher demand for regulation. The hydro producers are then required to produce at maximum capacity more frequently to balance the power system.



(a) Initial wind series



(b) New wind series

Figure 79: Area price in Sorland and corresponding hydropower production in Tonstad for Mid30 using the new and initial wind series

To conclude, the introduction of the new wind series with increased wind power production has reduced the need for hydropower plants to regulate power production. As a result, the hydro plants can operate more consistently at the level that offers the highest efficiency. This trend is most evident in the Mid30-W and Nor30-W scenarios, where wind power production is evenly distributed, as observed in Figure 61, leading to fewer occurrences of high prices. Conversely, in the Sor30-W scenario, wind power production shows larger fluctuations leading to a higher demand for regulation. More occurrences of max and min hydro production are therefore observed for this scenario.

Value factor

The value factor for the hydropower plants Tonstad, Kvilldal, Frøystul and Vessingsjø when using the new wind series is shown in Table 12. Compared to the value factor presented in Table 10 for the initial wind series, it is evident that the value factor generally increases when using the new wind series, with Tonstad in scenario Sor30-W being the only exception.

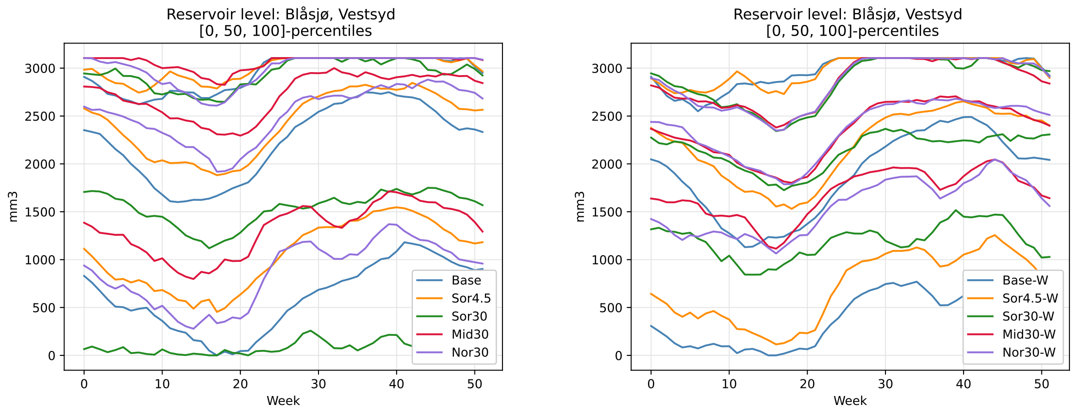
Table 12: Value factor for Tonstad, Kvilldal, Frøystul and Vessingsjø using the new wind series

	Base-W	**Sor4.5-W**	**Sor30-W**	**Mid30-W**	**Nor30-W**
Tonstad, Sorland	1.111	1.211	1.717	1.557	1.622
Kvilldal, Vestsyd	1.323	1.413	3.012	2.615	2.689
Frøystul, Telemark	1.140	1.162	1.244	1.438	1.420
Vessingsjø, Norgemidt	1.225	1.254	1.484	1.845	1.818

7.2.5 Reservoir level

Figure 80-82 compares the reservoir level for the initial and new wind series in the reservoirs previously examined, namely Blåsjø, Møsvatn and Trollheim. When examining the reservoir levels across the reservoirs and studying the impact of the new wind series, it is challenging to identify clear and consistent trends.

The reservoir level in Blåsjø is displayed in Figure 80. It is observed that the reservoir level in Base-W and Sor4.5-W have instances of lower reservoir level compared to Base and Sor4.5. However, for the scenarios with 30 GW wind power capacity, the percentiles representing the reservoir level are concentrated within a narrower range, implying that the reservoir capacity is less utilized when using the new wind series. This trend is particularly evident in the 0-percentile for Sor30-W, which is significantly higher than the 0-percentile for Sor30. This indicates less hydropower production for the new wind series compared to the initial. Moreover, the clustered percentiles shown for Mid30-W and Nor30-W indicate that the reservoir is not operating optimally, as it would be preferable to utilize more of its capacity.

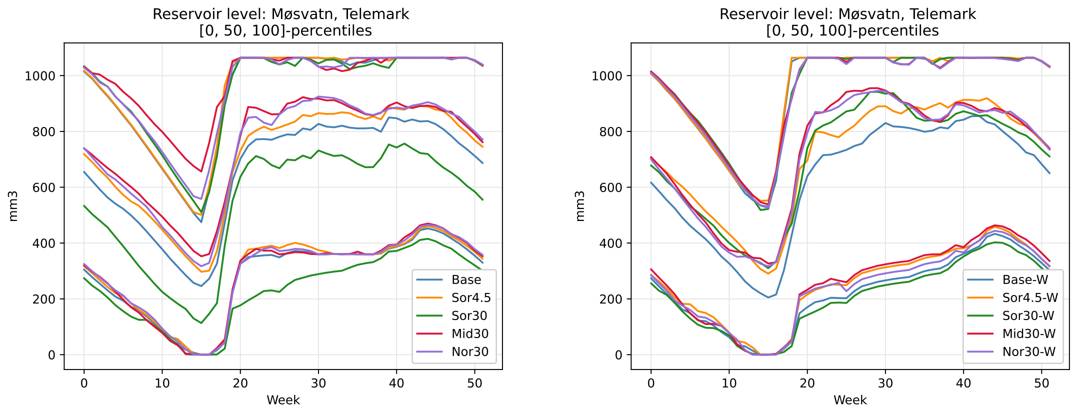


(a) Initial wind series

(b) New wind series

Figure 80: Reservoir level in Blåsjø for all scenarios using the initial and new wind series

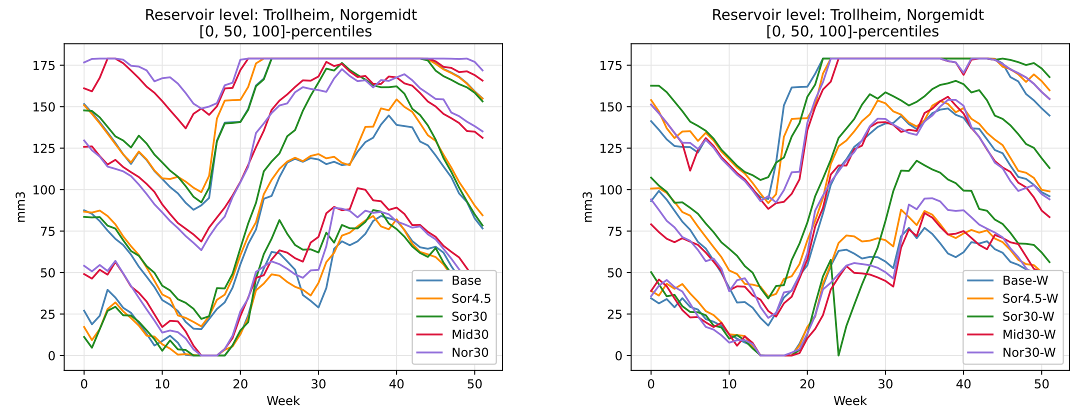
Figure 81 provides an overview of the reservoir level in Møsvatn using the initial and new wind series. Generally, there is a slight decrease observed in the reservoir level across the scenarios for the new wind series. Additionally, the differences in reservoir levels between the various scenarios are less pronounced compared to the initial wind series.



(a) Initial wind series (b) New wind series

Figure 81: Reservoir level in Møsvatn for all scenarios using the initial and new wind series

Figure 82 display the reservoir level in Trollheim for the initial and new wind series. Compared to the initial wind series, Base-W, Sor4.5-W, and Sor30-W experience higher reservoir levels, while Mid30-W and Nor30-W obtain lower reservoir levels.



(a) Initial wind series (b) New wind series

Figure 82: Reservoir level in Trollheim for all scenarios using the initial and new wind series

7.2.6 Social welfare

Table 13 presents the producer surplus, consumer surplus, the surplus of the transmission system operator (TSO), the costs of reservoir changes and social welfare for the entire system for all scenarios using the new wind series. The relative difference from the corresponding value when using the initial wind series is indicated in cursive below each value. For example, the producer surplus for Base-W is 192.83 Mrd kr lower than the producer surplus for Base.

Table 13: Producer surplus, consumer surplus, surplus of TSO, cost of reservoir changes and social welfare for all scenarios using the new wind series

	Producer surplus [Mrd kr]	**Consumer surplus [Mrd kr]**	**Surplus of TSO [Mrd kr]**	**Cost of reservoir changes [Mrd kr]**	**Social welfare [Mrd kr]**
Base-W	765.26 *-192.83*	63 611.16 *+258.28*	125.38 *+0.41*	-0.83 *-0.43*	64 500.98 *+65.42*
Sor4.5-W	744.58 *-192.20*	63 632.09 *+257.03*	127.36 *-0.18*	-0.73 *-0.35*	64 503.30 *+64.29*
Sor30-W	710.16 *-158.32*	63 661.18 *+225.93*	134.71 *-7.31*	-2.99 *-1.01*	64 503.07 *+59.29*
Mid30-W	706.32 *-148.13*	63 664.62 *+216.20*	135.21 *-8.44*	-2.89 *-0.93*	64 503.27 *+58.70*
Nor30-W	705.90 *-149.69*	63 665.06 *+217.84*	135.22 *-8.50*	-2.93 *-0.97*	64 503.25 *+58.69*

The producer surplus decreases across all scenarios for the new wind series. This is anticipated due to the decrease in area price for the new wind series. The largest decline in producer surplus is observed in Base-W and Sor4.5-W. However, the relative ranking of producer surplus among the scenarios remains unchanged, with Base-W having the highest producer surplus and Nor30-W having the lowest.

The new wind series results in an increase in consumer surplus, primarily attributed to the reduced area price. The increase in consumer surplus is especially high for Base-W and Sor4.5. Moreover, Nor30-W has now slightly surpassed Mid30-W in terms of having the highest consumer surplus.

The surplus of the transmission system operator shows varying differences between the initial and the new wind series. For Base-W, there is an increase compared to the initial wind series. This can be attributed to the observed higher wind power production in the new wind series, which in turn leads to more bottlenecks in the transmission system, as evidenced by the previous transmission analysis for the new wind series. However, for scenarios with greater offshore wind power production in the system, the surplus for the transmission system operator decreases. This effect is particularly evident in scenarios with 30 GW wind power production in Norway. It has been observed that these scenarios experience a higher frequency of zero transmission. This increased occurrence of zero transmission is likely a contributing factor to the decrease in surplus for the transmission system operator.

The cost of reservoir changes has considerably increased across all scenarios for the new wind series. Upon closer examination, it becomes apparent that this is mainly due to an increase in the cost of reservoir changes for France.

The described observations contribute to an overall increase in social welfare for all scenarios when utilizing the new wind series, primarily driven by the substantial rise in consumer surplus. The highest social welfare is observed in the Sor4.5-W scenario, in contradiction to the results from the initial wind series which displayed higher social welfare for the scenarios with 30 GW offshore wind capacity in Norway.

8 Discussion

The results discussed in this section are presented in section 7.

8.1 Impact of 30 GW offshore wind power in Norway

The objective of this thesis is to analyze the impact of 30 GW offshore wind power in Norway. The results clearly demonstrate that the substantial increase in wind power production has a significant effect on the power system. The study found that with higher wind power production in the system, there is a decrease in area price, which aligns with the findings from the literature search in section 3.5.2. In the Norwegian areas, the impact was especially pronounced, with frequent instances of nearly zero prices in areas directly connected to offshore wind power production. The most notable situation occurred in the northern areas in the Nor30 scenario.

Wind power has a marginal cost of zero. Consequently, the increased wind power production results in a decrease in area price due to the merit-order effect. However, it should be noted that the substantial energy production added to the Norwegian power system, without a corresponding increase in demand, could impact the area price regardless of the energy source. This observation is supported by the study conducted by Helisö *et al.* [68], discussed in section 3.5.2, which concluded that the amount of base load generation capacity and overcapacity has a more significant impact on electricity prices compared to the share of intermittent renewable and the cost of CO_2. For the analysis conducted in this thesis, it remains unclear how much of the price decrease that can be attributed to the power surplus and how much is specifically due to the share of wind power production. Conducting a comparative analysis by equally increasing power production using other sources could provide insights into this matter.

The direct integration of 30 GW offshore wind power production into the Norwegian power system, without any corresponding upgrades to the transmission capacity, places increased strain on the transmission system and results in a higher frequency of bottlenecks. This is particularly evident in the cross-border interconnections from Norway, which almost consistently operate at maximum capacity in order to export power. These observations indicate that the addition of 30 GW capacity is excessive for the Norwegian power system to handle, thereby supporting Statnett's statement that a portion of the offshore wind power should be directly linked to foreign countries or offshore industries [54]. Within the Norwegian internal transmission system, the most significant strain is observed in the lines serving the high-demand area Ostland, particularly pronounced in the Sor30 scenario due to the significant offshore wind power production in southern Norway. Statnett has recognized the need to reinforce the transmission grid between Sorland and Ostland to facilitate for offshore wind production in the south of Norway [54]. However, it is worth noting that Statnett's expectations for the next ten to fifteen years involve the connection of 3-4.5 GW offshore wind capacity from Sørlige Nordsjø II [54]. The connection of 15 GW of offshore wind to Sorland, along with an additional 15 GW in Vestsyd as depicted in the Sor30 scenario, represents an extreme situation that is not anticipated to be realized in the near future.

The line between Norgemidt and Helgeland is especially interesting to study when examining the power flow between the northern and southern parts of Norway. In general, there is a tendency for power flow from the northern to the southern areas, driven by higher power production and lower power demand in the north. This trend is less pronounced for the Mid30 scenario due to significant power production in the south. However, for the Nor30 scenario, where power production in the north increases due to offshore wind generation, there is a substantial rise in power flow from Helgeland to Norgemidt. In this scenario, the area price in Helgeland, Troms, and Finnmark remains near zero for over 90% of the time. Moreover, the transmission lines out of these areas almost constantly operate at maximum capacity to export power, indicating a surplus supply. These findings underscore that despite the potential for power production in northern Norway, any developments must align with the transmission capacity and demand in the region, considering the relatively lower power demand in the north. In Statnett's report regarding the integration of offshore wind [54], it is emphasized that a significant power surplus in the north of Norway would result in a net southward power flow, leading to bottlenecks and operational challenges in the network. Therefore, it is crucial to ensure effective interaction between new production and new consumption. The report further states that significant growth in power consumption is anticipated in Finnmark, primarily driven by the electrification of the petroleum industry. By strengthening transmission lines that facilitate power transfer to power-demanding industries, the region can benefit from offshore wind development.

Three scenarios involving 30 GW offshore wind power capacity in Norway have been studied to examine the impact of wind farm locations. In Sor30, the wind power capacity is concentrated in the southern region, whereas the capacity is more distributed throughout the country in Mid30 and Nor30. The concentration of offshore wind production in Sor30 leads to significant strain on the Norwegian transmission system in order to distribute the power to other areas. Nevertheless, the considerably higher area prices observed in the Norwegian areas for Sor30 compared to Mid30 and Nor30 indicate suboptimal power distribution due to transmission constraints. Furthermore, as there is only one set of wind series defining the wind power production in each area, the 15 GW wind capacity in each of the two areas is influenced by the same wind conditions. This leads to significant fluctuations in wind production, ranging from maximum production to zero production. In contrast, a more spread distribution of wind farms in Mid30 and Nor30 makes the system less vulnerable to such large fluctuations. Finally, the analysis revealed that Mid30 and Nor30 resulted in higher social welfare compared to Sor30. This finding aligns with the recommendations provided by NVE and Statnett regarding the distribution of wind farms, discussed in the literature study of this thesis. However, as demonstrated for the northern region of Norway in the Nor30 scenario, this requires that the distribution of wind farms aligns with energy demand to ensure optimal utilization of energy production and avoid excess supply.

Norway has historically relied on hydropower as its primary source of energy production. With the increasing share of wind power in the Norwegian energy mix, it is interesting to examine the consequential effects on hydropower production. The result from this thesis showed that hydro production adjusts accordingly to wind power production. This result demonstrates the important role of hydropower in the integration of intermittent wind power production due to its flexible characteristic. The frequent occurrence of low-price periods, where hydro production is zero, causes hydropower plants to operate at maximum capacity during periods of low wind power generation to avoid spillage. Consequently, as the capacity of wind power increases, hydropower plants tend to operate more frequently either at maximum capacity or with zero production. It was observed that this results in less frequent ramping in scenarios with 30 GW offshore wind capacity. Nevertheless, these scenarios demonstrated a more frequent occurrence of ramping directly from zero production to maximum capacity. It is important to note, however, that such ramping may not occur as frequently in real-life situations due to potential increased stress on the system.

The hydropower producer benefits from the fluctuating area prices, driven by wind power production, by producing power when the price is higher and stopping production during low-price periods. Consequently, the value factor for the hydropower plants increases for more wind power production in the system. This finding aligns with the research conducted by Schäffer *et al.* [72] discusses in section 3.5.3, which highlights that the value of flexibility rises with the increasing penetration of variable renewable energy in the system. While the value factor is higher for increased wind power production in the system, it is important to acknowledge that hydro producers still experience reduced income in these scenarios due to the observed decline in area prices.

The increased value factor suggests good market conditions for flexibility providers. A power system with a high proportion of intermittent renewable energy must have sufficient flexible resources. The analysis conducted in this thesis focuses on the impact on hydro producers. However, it is worth considering that other flexibility suppliers, such as batteries, may also experience an increased value of flexibility. Further investigation into the value factor for shorter time horizons, such as 24 or 72 hours, would provide insights into this aspect. Exploring alternative sources of flexibility, in addition to hydropower, will contribute to a more resilient power system, particularly in areas with limited access to hydropower resources.

8.2 New wind series

During the spring of 2023, SINTEF Energy Research generated a new set of wind series for the dataset, which initiated a study to compare them with the wind series initially included in the dataset. The findings revealed that the new wind series resulted in more wind power production in the system. Additionally, it was observed that the total wind power capacity varied between the initial and new wind series. As both wind series utilize the same dataset with identical conversion factors for wind power production in each area, this implied that there were differences in the maximum values between the two wind series. This was confirmed when analyzing the wind series in detail.

The utilization of the new wind series amplifies the impact of wind power production on area prices, due to the increased wind power generation for these wind series. Consequently, the area prices exhibit a more substantial decline compared to the initial wind series across all scenarios. In the scenarios with 30 GW of wind power production, there is a significant occurrence of prices close to zero. The surplus power in various parts of Norway leads to increased instances of zero transmission, as multiple areas simultaneously experience zero prices.

The introduction of the new wind series with increased wind power production has reduced the need for hydropower plants to regulate power production. As a result, the hydro plants can operate more consistently at the level that offers the highest efficiency. This trend is most evident in the Mid30-W and Nor30-W scenarios, where wind power production is evenly distributed. For Base-W and Sor4.5-W, as well as Sor-W in certain hydro plants, wind power production display significant fluctuations, resulting in an increased need for regulation. Consequently, these scenarios reveal a greater frequency of maximum and minimum hydro production, aligning with the pattern observed when using the original wind series. When analyzing the reservoir level for the new wind series, identifying consistent trends across all hydro plants proved to be a challenge. The impact of increased wind production on the reservoir level showed considerable variations across different reservoirs. Blåsjø demonstrated the most notable changes in reservoir level compared to the initial wind series. In scenarios involving 30 GW offshore wind, the 0-percentile in Blåsjø where significantly higher. This indicates that the reservoir is not operating optimally, as it would be preferable to utilize more of its capacity

The Sor4.5-W scenario obtained the highest social welfare for operating the power system, slightly surpassing the scenarios involving 30 GW offshore wind power. This outcome stands in contrast to the findings obtained using the initial wind series, where the scenarios with 30 GW offshore wind displayed the highest social welfare. Since the increased wind power production resulting from the new wind series leads to an even greater discrepancy between power production and demand in Norway, this result suggests that aligning wind power expansion with power demand and transmission capacity is beneficial in terms of social welfare.

The simulations conducted with the new wind series revealed substantial disparities in the results compared to those obtained from the initial wind series. This emphasizes the crucial role of the wind series in simulations involving high levels of wind power production. In FanSi, the users can specify a conversion factor that determines the installed capacity, but it is the wind series that defines the level and variability of wind power generation across the load periods. As the proportion of wind power in the system increases, the impact of the wind series on the results becomes increasingly significant. Therefore, having wind series that accurately reflect the variations in wind conditions becomes crucial for future simulations concerning wind power production.

8.3 Limitations and potential weaknesses of the study

In order to ensure the appropriate utilization of the results derived from the simulations conducted in this thesis, this section will discuss the study's limitations and weaknesses.

The scenarios in this study were defined based on the most current information available regarding offshore wind development in Norway. However, this subject is highly relevant, with frequent developments. In April 2023, NVE presented an analysis identifying new areas for offshore wind development in Norway [56]. These latest findings have not been taken into account for the simulations conducted in this thesis.

This case study provides a simplified representation of a large-scale offshore wind power implementation in Norway. The dataset utilized in the analysis has been adjusted to align with the scenarios to the best extent possible, considering the available areas. In Norway, there are only five offshore areas in the dataset, none of which are located in the northern region. Consequently, the allocation of offshore wind capacity in Norway in this analysis is concentrated within these five offshore areas. The limited number of offshore areas results in a less extensive distribution of offshore capacity, leading to a high level of power production being transferred to the same onshore area. Moreover, since each offshore area relies on the same wind series, a significant portion of the wind capacity experiences the same variations in power production. In reality, wind farms would be subject to more varying wind conditions. Lastly, due to the absence of offshore wind areas in the north, the offshore wind power in the Nor30 dataset is added to the onshore areas. Onshore areas typically have less favourable wind conditions compared to offshore areas, which is reflected in the wind series used in this study. Therefore, using onshore areas to represent offshore wind power, leads to less wind power production for the northern offshore wind farms. The scenarios would therefore have been represented more accurately with more offshore areas in the dataset.

Another simplification made in this case study concerns the transmission system used in the analysis. It is assumed that all wind power capacity is directly connected to the nearest onshore area. Furthermore, the transmission capacity in the onshore lines remains unchanged despite the increased wind power production in the country. These simplifications deviate from the expected implementation when expanding offshore wind production in Norway. When the government presented plans to allocate areas for 30 GW of offshore wind power in Norway, they emphasized that this capacity is too large for the Norwegian grid to accommodate, making it necessary to export a share of the power production. Moreover, as elaborated in section 3.3.2, Statnett has highlighted that such a development would require further measures in the power system, including onshore grid development, flexible consumption, and changes in system operation [54]. They have also stated that a portion of the offshore wind power will be linked directly to foreign countries or offshore industries. Since these transmission factors were not considered in the analysis conducted in this thesis, it has led to an overload of power supply to the Norwegian power system, resulting in transmission bottlenecks and frequently zero pricing. Moreover, the demand in the Norwegian areas remains constant, despite the significant increase in power production. In reality, there is a stronger correlation between the demand and the development of new production. Due to these simplifications, this analysis should be interpreted as an assessment of the impact of significant wind power production on the Norwegian power system, rather than an accurate representation of the future situation in Norway when the plan of achieving 30 GW of offshore wind production is realized.

The primary findings presented in this analysis are based on the wind series initially included in the dataset. However, the result obtained when using the new wind series revealed notable differences compared to the results from the simulations using the initially included wind series, due to more wind power production resulting from the new wind series. The new wind series is reported to provide higher geographical and temporal resolution compared to the wind series included in the dataset. Consequently, the results obtained from the new wind series are potentially more accurate. Nevertheless, the comparison of the wind series highlights the significance of the choice of wind series and its consequential impact on the outcomes of the analysis.

During the analysis of reservoir levels, an issue related to the end value setting was identified for the scenarios with 30 GW offshore wind capacity, as discussed in section 5.2.1. In consultation with the supervisor from SINTEF Energy Research, it was decided to not group the areas when calculating the water values in EMPS for the scenarios with 30 GW offshore wind capacity. This method improved the water values derived from the EMPS model. However, it is important to acknowledge that this solution is considered a simplification and does not provide an optimal end valuation. It is therefore important to acknowledge the potential influence of the end valuation on the result. This influence becomes particularly evident in the case of reservoir levels. For instance, the reservoir level in Blåsjø obtained in the simulations using the new wind series displayed suboptimal outcomes for scenarios involving 30 GW wind capacity, despite the change in end value setting. Additionally, the utilization of groups ("Samkjøringsområder") in water value calculations for the Base and Sor4.5 scenarios, while the scenarios with 30 GW offshore wind capacity do not utilize groups, may introduce certain issues when comparing the scenarios with different end value setting calculations. Notably, it was observed that changing the calculation of the end value setting for scenarios involving 30 GW wind capacity led to higher costs of reservoir changes in GB-north and France. Since this is outside the scope of this thesis, further investigation was not conducted, however, it is worth considering that it may have influenced the outcome in terms of social welfare. Ideally, model calibration should be conducted to adjust the water values derived from EMPS. However, in the simulations performed for this thesis, the focus was primarily on Fansi rather than the EMPS model. Consequently, model calibration was not prioritized. Nevertheless, it has become apparent that the substantial changes in the system necessitate calibration of the end values. Alternatively, increasing the time horizon of the scenario fan would have mitigated the impact of the end-value setting on the results. It should also be noted that an extensive investigation into the causes of the issue regarding the end value setting has not been conducted, which introduces some uncertainties regarding the reasons for its occurrence.

9 Conclusion

This master's thesis has investigated the impact of increased offshore wind power on the Norwegian power system using the fundamental market model FanSi. The analysis utilized a dataset representing a scenario for the Northern European power system in 2030. The study examined five offshore wind capacity scenarios in Norway, including one with zero power production, another with 4.5 GW in the south, and three with 30 GW distributed across different regions of the country. The offshore capacity was directly connected to the nearest onshore area without corresponding modifications to the transmission system and demand. Two sets of wind series were employed in the simulations to analyze and compare the recently generated wind series by SINTEF Energy Research with the original wind series initially included in the dataset.

The study found that as wind power production increased in the system, there was a noticeable decrease in area price, with the average area price in Norway decreasing from 305.11 NOK/MWh in the Base scenario to 20.71 NOK/MWh in the Nor30 scenario. The Nor30 scenario exhibited the most significant occurrence, with prices close to zero observed over 90% of the time in the northern areas. The transmission lines from these areas consistently operated at maximum capacity to export power, indicating a surplus of supply. Overall, the integration of 30 GW offshore wind power production into the Norwegian power system without corresponding upgrades to the transmission capacity resulted in increased strain on the transmission system and a higher frequency of bottlenecks. This strain was particularly evident in the cross-border interconnections from Norway, which consistently operated at maximum capacity to export power. These findings emphasize the importance of aligning wind power developments with plans for transmission capacity expansion and new demands and electrification projects.

The analysis revealed that hydropower plants operate more frequently either at maximum capacity or with zero production as the wind power capacity increases. Furthermore, the scenarios with 30 GW offshore wind capacity experienced less frequent ramping in hydropower production. The value factor for hydropower plants increased with higher wind power production in the system, as the hydropower producer benefits from the fluctuating area prices driven by wind power production. The analysis of reservoir levels indicated a trend of rising levels with higher wind power production.

When comparing the three scenarios of 30 GW offshore wind power in Norway, it was found that the concentration of wind production in Sor30 strained the transmission system, resulting in higher area prices compared to the other 30 GW scenarios. Furthermore, Sor30 experienced significant fluctuations in wind production due to identical wind conditions, whereas Mid30 and Nor30, with more dispersed wind farms, were less susceptible to such large fluctuations.

The results revealed that social welfare is positively impacted by greater wind power production in the system, primarily driven by increased consumer surplus and surplus of the TSO. Mid30 and Nor30 result in higher social welfare compared to Sor30, supporting the distribution of wind farms.

The new wind series resulted in increased wind power production within the system compared to the original wind data set. As a result, the area prices experienced an additional decline for the new wind series, with the lowest average area price in Norway being 5.93 NOK/MWh, observed in the Mid30-W scenario. Moreover, the increase in power production led to more instances of zero transmission, as multiple areas simultaneously experience zero prices. When comparing wind production across the scenarios, it was evident that the new wind series more effectively captures the impact of distributing wind capacity across different areas. The increased wind power production resulting from the new wind series has reduced the need for hydropower plants to regulate power production. Lastly, the Sor4.5-W scenario obtained the highest social welfare for operating the power system when using the new wind series, slightly surpassing the scenarios involving 30 GW offshore wind power.

During the simulations conducted in this thesis, an issue related to the end value setting was identified. It was found that the water values derived from the EMPS model for scenarios with large amounts of wind power production were excessively high. While a simplified solution was identified and implemented for the simulations conducted in this thesis, these findings emphasize the importance of further investigations into this issue.

10 Further work

This section presents suggestions for future research based on the findings in this thesis.

The objective of the simulations conducted in this thesis was to investigate the consequences of 30 GW offshore wind power capacity in Norway. However, certain simplifications were made in the process, which may have impacted the accuracy of the results obtained. For further studies on 30 GW offshore wind in Norway, it would be valuable to place greater emphasis on the transmission system. Incorporating a more realistic transmission system that includes direct export to foreign countries, offshore hybrid grid solutions, and increased onshore transmission capacity would provide a more accurate depiction of the development of 30 GW offshore wind in Norway. Furthermore, such an analysis could assist in determining the optimal grid solution for Norwegian offshore wind development. As mentioned previously, the case study conducted in this thesis does not take into account the new offshore areas identified by NVE in April 2023. For future studies, it would be advantageous to incorporate the most up-to-date plans for offshore wind sites in order to obtain more realistic results.

Another suggestion for future case studies is to investigate an electrification scenario, emphasizing the importance of strategically coordinating production and consumption. Such an electrification scenario can be achieved by increasing demand in areas where offshore wind power is directly connected. This approach will lead to more realistic simulations, reducing the large surplus of supply observed in the current thesis. Furthermore, it will provide valuable insights into the impact of wind power production fluctuations on consumers. This includes examining the consumer's response and vulnerability during periods of low wind power production, which is more difficult to identify in the current thesis due to the significant power surplus.

The dataset utilized in this thesis imposes limitations on the level of detail achievable in the simulation. The dataset represents Norway using 11 onshore areas and 5 offshore areas. However, the northern part of Norway is not represented in terms of offshore areas. To make the dataset more suitable for offshore wind power simulations, more offshore areas should be included, especially in the northern region of Norway. Increasing the number of offshore areas will result in a more realistic representation of wind power, as the wind capacity is distributed on more wind series.

This thesis includes an analysis of wind series, as the scenarios were simulated using two different sets of wind series. The results revealed substantial disparities between the results obtained from the two sets of wind series. The new wind series is claimed to provide higher geographical and temporal resolution compared to the initial wind series included in the dataset. They also showed a more consistent behaviour, particularly concerning the maximum values, where inconsistencies were observed in the initial wind series. As wind power production increases, the significance of accurate wind series becomes more pronounced for future studies. Consequently, it is crucial to continue generating updated wind series and replace outdated ones to ensure the reliability of simulations.

During the simulation process, an issue concerning the end value setting was discovered, showing that the water values derived from the EMPS model were excessively elevated for the scenarios with large amounts of wind power production. In theory, Fansi should be able to operate almost independently of EMPS if the scenario lengths are extended sufficiently. However, in practice, due to computational constraints, shorter scenario lengths are used, making the end valuation more crucial for the results. This is a weakness in FanSi that requires further investigation. SINTEF is working on this issue, and it is anticipated that the next generation market model, built upon Fansi, will be better equipped to handle this challenge. In such a case, streamlining the solution methodology in Fansi, along with utilizing an alternative and non-calibrated end value source, will lead to more robust behaviour.

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Appendix

A Dataset

A.1 Control input file


```
<?xml version="1.0"?>
<FANSICTRL>
<ControlData>
    <Variable> <NAME> NWEEKSCEN </NAME> <VALUE> 52 </VALUE> <COMMENT> Number of weeks in the scenario - fan </COMMENT> </Variable>
    <Variable> <NAME> NSCEN </NAME> <VALUE> 8 </VALUE> <COMMENT> Number of scenario in the fan </COMMENT> </Variable>
    <Variable> <NAME> LSEKV </NAME> <VALUE> F </VALUE> <COMMENT> Sequential (T) or accumulated (F) time resolution </COMMENT> </Variable>
    <Variable> <NAME> LONERESCON </NAME> <VALUE> F </VALUE> <COMMENT> Use one reservoir const in week (T), else (F) </COMMENT> </Variable>
    <Variable> <NAME> LASTWEEKSEQ </NAME> <VALUE> 1 </VALUE> <COMMENT> Last week with sequential time res. </COMMENT> </Variable>
    <Variable> <NAME> LASTWEEKACC </NAME> <VALUE> 1 </VALUE> <COMMENT> Last week with acc. time res. oppl. </COMMENT> </Variable>
    <Variable> <NAME> USEHEAD </NAME> <VALUE> F </VALUE> <COMMENT> Use head for production and strategy. True(T) or False(F) </COMMENT> </Variable>
    <Variable> <NAME> RESMINLIMIT </NAME> <VALUE> 0.20000000D+00 </VALUE> <COMMENT> Limit of inclusion of reservoir constraints [Mm3] </COMMENT> </Variable>
    <Variable> <NAME> MAXDIFF </NAME> <VALUE> 0.99999997D-05 </VALUE> <COMMENT> Criteria for Benders iterations [%] </COMMENT> </Variable>
    <Variable> <NAME> MAXITER </NAME> <VALUE> 10 </VALUE> <COMMENT> Max number of Bender iterations </COMMENT> </Variable>
    <Variable> <NAME> EXPECTED </NAME> <VALUE> F </VALUE> <COMMENT> Use an expected scenario (NSCEN == 1) </COMMENT> </Variable>
    <Variable> <NAME> SMOOTHWV </NAME> <VALUE> F </VALUE> <COMMENT> Experimental: Use smoothing of end value setting (T) or (F) </COMMENT> </Variable>
    <Variable> <NAME> TARGETRES </NAME> <VALUE> T </VALUE> <COMMENT> Experimental: Use target reservoir calculations. (T) or (F) </COMMENT> </Variable>
    <Variable> <NAME> SOLVERALG </NAME> <VALUE> 0 </VALUE> <COMMENT> Experimental: solver algorithm 0 = dual 1= barrier, 2=concur </COMMENT> </Variable>
    <Variable> <NAME> CPLEXLOG </NAME> <VALUE> F </VALUE> <COMMENT> Print cplex.log-file </COMMENT> </Variable>
    <Variable> <NAME> NTHREADS_SCEN </NAME> <VALUE> 1 </VALUE> <COMMENT> Threads solving scenario (Barrier) </COMMENT> </Variable>
    <Variable> <NAME> NTHREADS_MSTR </NAME> <VALUE> 1 </VALUE> <COMMENT> Threads solving master (Barrier) 0=>NSCEN </COMMENT> </Variable>
</ControlData>
<SES>
    <Variable> <NAME> START </NAME> <VALUE> 1 </VALUE> <COMMENT> First week of season in auto regr. model </COMMENT> </Variable>
    <Variable> <NAME> END </NAME> <VALUE> 104 </VALUE> <COMMENT> Last week of season in auto regr. model </COMMENT> </Variable>
</SES>
<PENALTYVAR>
    <Variable> <NAME> CSPILL </NAME> <VALUE> 0.20000000D-01 </VALUE> <COMMENT> Small penalty for spillage [MonetaryUnit/Mm3] </COMMENT> </Variable>
    <Variable> <NAME> CBYPASS </NAME> <VALUE> 0.99999998D-02 </VALUE> <COMMENT> Small penalty for bypass [MonetaryUnit/Mm3] </COMMENT> </Variable>
    <Variable> <NAME> CPENUPPERRES </NAME> <VALUE> 0.10000000D+02 </VALUE> <COMMENT> Penalty for Max reservoir [MonetaryUnit/Mm3] </COMMENT> </Variable>
    <Variable> <NAME> CPENRES </NAME> <VALUE> 0.90000000D+03 </VALUE> <COMMENT> Penalty for Min reservoir [MonetaryUnit/Mm3] </COMMENT> </Variable>
    <Variable> <NAME> CPENQMIN </NAME> <VALUE> 0.70000000D+02 </VALUE> <COMMENT> Penalty for QMIN [MonetaryUnit/Mm3] </COMMENT> </Variable>
    <Variable> <NAME> CPENQFOMIN </NAME> <VALUE> 0.90000000D+03 </VALUE> <COMMENT> Penalty for QFOMIN [MonetaryUnit/Mm3] </COMMENT> </Variable>
    <Variable> <NAME> CBufferCURVE </NAME> <VALUE> 0.70000000D+02 </VALUE> <COMMENT> Penalty deviation: buffercurve [MonetaryUnit/Mm3] </COMMENT> </Variable>
</PENALTYVAR>
<GRID>
    <Variable> <NAME> RGRIDDATA </NAME> <VALUE> F </VALUE> <COMMENT> Use grid data. True (T) or False (F). </COMMENT> </Variable>
    <Variable> <NAME> DETGRID </NAME> <VALUE> F </VALUE> <COMMENT> Use detailed grid data. True (T) or False (F). </COMMENT> </Variable>
    <Variable> <NAME> PTDFWEIGHT </NAME> <VALUE> 1 </VALUE> <COMMENT> Weighting scheme for aggr. PTDFS 1=injection, 2=flat. </COMMENT> </Variable>
    <Variable> <NAME> GRIDDATAFILE </NAME> <VALUE> GridFile.csv </VALUE> <COMMENT> File name grid data.</COMMENT> </Variable>
    <Variable> <NAME> GRIDSCEN </NAME> <VALUE> F </VALUE> <COMMENT> Use grid data in scenario fan </COMMENT> </Variable>
</GRID>
<WaterValue>
    <Variable> <NAME> SAVECUT </NAME> <VALUE> F </VALUE> <COMMENT> Save cut for each iteration, week, year </COMMENT> </Variable>
    <Variable> <NAME> SAVEWATERVALUES </NAME> <VALUE> T </VALUE> <COMMENT> Save water values inside of a week for all modules </COMMENT> </Variable>
    <Variable> <NAME> SaveIndvanForWeek </NAME> <VALUE> 0 </VALUE> <COMMENT> Save given week in indvan (0 not use) </COMMENT> </Variable>
    <Variable> <NAME> IndvanWithinWeek </NAME> <VALUE> T </VALUE> <COMMENT> Indvan: true (T) WV inside of week, false (F) cut </COMMENT> </Variable>
    <Variable> <NAME> SAVEENDWVSCEN </NAME> <VALUE> T </VALUE> <COMMENT> Save End-WV in scenario-fan </COMMENT> </Variable>
```


Figure 83: The file *Fansi-ctrl.xml*. Only a partial list of the parameters contained in the file is shown here.

A.2 List of steps

```
  57,                                                           << Antall delomr}der i Samkj/ringsmodellen
   1,'OSTLAND             ',                                    << Delomr}denr og navn
  27,                                                           << Antall trinn
   1,'DUMMY               ',   3,'Varmekraft                  ', << Trinnr og navn, Katergorinr og navn
   6,'KJELKRAFT LETT 1    ',   9,'Salg refert lastprofil      '
   7,'KJELKRAFT LETT 2    ',   9,'Salg refert lastprofil      '
   8,'KJELKRAFT LETT 3    ',   9,'Salg refert lastprofil      '
   9,'KJELKRAFT LETT 4    ',   9,'Salg refert lastprofil      '
  42,'KJELKRAFT TUNG BASIS',   9,'Salg refert lastprofil      '
  43,'KJELKRAFT TUNG REG1V',   9,'Salg refert lastprofil      '
  44,'KJELKRAFT LETT 5    ',   9,'Salg refert lastprofil      '
  50,'HAFSLUND DENOFA     ',   3,'Varmekraft                  '
  51,'HAFSLUND BORREG]RD  ',   3,'Varmekraft                  '
  52,'KAKEN TURBOSENTRAL  ',   3,'Varmekraft                  '
  53,'TOFTE BUSKERUD EVERK',   3,'Varmekraft                  '
  54,'FJERNVARME DRAMMEN  ',   3,'Varmekraft                  '
  55,'MOTTRYKK A/S FOLLUM ',   3,'Varmekraft                  '
  56,'TOFTE BUSKERUD      ',   3,'Varmekraft                  '
  57,'KLEMENTSRUD OSLO    ',   3,'Varmekraft                  '
  80,'EXCH-GLOM           ',   1,'Tilfeldigkraft kj|p og import '
 998,'FLOMKRAFT           ',  20,'Flomkraft                   '
 999,'Rasjonering         ',  40,'Rasjonering                 '
 401,'Pa. Kjop DELLAST  1 ',  30,'Prisavhengighet for dellast  '
 402,'Pa. Kjop DELLAST  1 ',  30,'Prisavhengighet for dellast  '
 403,'Pa. Kjop DELLAST  1 ',  30,'Prisavhengighet for dellast  '
 404,'Pa. Kjop DELLAST  1 ',  30,'Prisavhengighet for dellast  '
 405,'Pa. Kjop DELLAST  1 ',  30,'Prisavhengighet for dellast  '
 406,'Pa. Salg DELLAST  1 ',  30,'Prisavhengighet for dellast  '
 407,'Pa. Salg DELLAST  1 ',  30,'Prisavhengighet for dellast  '
 408,'Pa. Salg DELLAST  1 ',  30,'Prisavhengighet for dellast  '
   2,'SOROST              ',                                    << Delomr}denr og navn
  24,                                                           << Antall trinn
   1,'KRAFTINTENSIV 1     ',   2,'Tilfeldigkraft salg og eksport', << Trinnr og navn, Katergorinr og navn
   2,'KRAFTINTENSIV 2     ',   2,'Tilfeldigkraft salg og eksport'
   3,'KRAFTINTENSIV 3     ',   2,'Tilfeldigkraft salg og eksport'
   4,'KRAFTINTENSIV 4     ',   2,'Tilfeldigkraft salg og eksport'
   5,'KRAFTINTENSIV 5     ',   2,'Tilfeldigkraft salg og eksport'
   6,'KJELKRAFT LETT 1    ',   9,'Salg refert lastprofil      '
   7,'KJELKRAFT LETT 2    ',   9,'Salg refert lastprofil      '
   8,'KJELKRAFT LETT 3    ',   9,'Salg refert lastprofil      '
   9,'KJELKRAFT LETT 4    ',   9,'Salg refert lastprofil      '
  12,'KJELKRAFT TUNG 1    ',   9,'Salg refert lastprofil      '
  21,'A/S UNION           ',   3,'Varmekraft                  '
  31,'KRAFTINTENSIV 6     ',   2,'Tilfeldigkraft salg og eksport'
```

Figure 84: The file *trinnliste.txt*, showing the price dependent steps. Only a partial list of the file is shown here.

A.3 Load periods

```
 1,   1,   1,   2,   2,   2,   3,   3,   3,   4,   4,   4,   5,   5,   5,   6,   6,   6,   7,   7,   7,   8,   8,   8,Mon
 9,   9,   9,  10,  10,  10,  11,  11,  11,  12,  12,  12,  13,  13,  13,  14,  14,  14,  15,  15,  15,  16,  16,  16,Tue
17,  17,  17,  18,  18,  18,  19,  19,  19,  20,  20,  20,  21,  21,  21,  22,  22,  22,  23,  23,  23,  24,  24,  24,Wed
25,  25,  25,  26,  26,  26,  27,  27,  27,  28,  28,  28,  29,  29,  29,  30,  30,  30,  31,  31,  31,  32,  32,  32,Thu
33,  33,  33,  34,  34,  34,  35,  35,  35,  36,  36,  36,  37,  37,  37,  38,  38,  38,  39,  39,  39,  40,  40,  40,Fri
41,  41,  41,  42,  42,  42,  43,  43,  43,  44,  44,  44,  45,  45,  45,  46,  46,  46,  47,  47,  47,  48,  48,  48,Sat
49,  49,  49,  50,  50,  50,  51,  51,  51,  52,  52,  52,  53,  53,  53,  54,  54,  54,  55,  55,  55,  56,  56,  56,Sun
```

Figure 85: The file *PRISAVSNITT.DATA*, showing the load periods.

A.4 Fuel prices

```
   1,    5,   52,# Versjonsnr fil, Antall brenselstyper, Sluttuke
'Bio'       ,0.0 ,3.5     ,# Brenselnavn, Utslipp CO2 i tCO2/t, Energikoeffisient MWh/t
  52        ,45.00,0.0,110.0,# Sluttuke, Pris brensel EUR/t, Avgift brensel EUR/t, Avgift CO2 i EUR/tCO2
'Lignite'   ,2.05,4.1     ,# Brenselnavn, Utslipp CO2 i tCO2/t, Energikoeffisient MWh/t
  52        ,153.0,0.0,110.0,# Sluttuke, Pris brensel EUR/t, Avgift brensel EUR/t, Avgift CO2 i EUR/tCO2
'Coal'      ,2.92,7.9     ,# Brenselnavn, Utslipp CO2 i tCO2/t, Energikoeffisient MWh/t
  52        ,153.0,0.0,110.0,# Sluttuke, Pris brensel EUR/tonn, Avgift brensel EUR/t, Avgift CO2 i EUR/tCO2
'Gas'       ,0.2 ,1.0     ,# Brenselnavn, Utslipp CO2 i tCO2/MWh, Energikoeffisient MWh/MWh
  52        ,31.5,0.0,110.0,# Sluttuke, Pris brensel EUR/MWh, Avgift brensel EUR/MWh, Avgift CO2 i EUR/tCO2
'Oil'       ,0.2 ,1.5     ,# Brenselnavn, Utslipp CO2 i tCO2/mmbbl, Energikoeffisient MWh/mmbbl
  52        ,139.5,0.0,110.0,# Sluttuke, Pris brensel EUR/mmbbl, Avgift brensel EUR/mmbbl, Avgift CO2 i EUR/tCO2
```

Figure 86: The file *BRENSEL.ARCH*.

A.5 Detailed system description

A.5.1 Average annual power production

The average annual power production for all areas in Norway is shown in Table 14. Table 15 displays the average annual power production for every country in the dataset. Both tables display the average annual power production from hydropower, wind power and solar power. Moreover, the total annual power production is displayed. To present the power production within each country, the regions in Denmark, Germany, and Great Britain are combined and represented as a single value for each respective country. Sweden is divided into north and south. Sweden-N consists of SVER-ON1, SVER-ON2, SVER-NN1 and SVER-NN2, whereas SVER-MIDT and SVER-SYD represent Sweden-S. Switzerland, the Czech Republic and Austria are only modelled with times series for power balance, and the average annual power balance in these countries is displayed in Table 16.

Table 14: Average annual power production for all areas in Norway

Area	**Hydro [TWh]**	**Onshore wind [TWh]**	**Offshore wind [TWh]**	**Solar [TWh]**	**Total power production[TWh]**
Ostland	14.13	2.36	0.00	0.46	17.13
Sorost	0.16	0.47	0.00	0.45	0.72
Hallingdal	14.22	0.00	0.00	0.00	14.22
Telemark	12.37	3.15	0.00	0.22	15.51
Sorland	20.65	2.12	0.10	0.45	22.87
Vestsyd	15.59	2.31	0.08	0.22	18.36
Vestmidt	23.99	0.07	0.09	0.07	24.15
Norgemidt	22.40	9.66	0.76	0.20	32.83
Helgeland	13.06	0.48	0.00	0.00	13.54
Troms	9.79	0.45	0.00	0.00	10.23
Finnmark	2.19	2.28	0.00	0.00	4.47
Total	**148.55**	**23.35**	**1.03**	**2.07**	**174.03**

Table 15: Average annual power production for the countries in the dataset

Country	Hydro [TWh]	Onshore wind [TWh]	Offshore wind [TWh]	Solar [TWh]	Total power production [TWh]
Norway	148.55	23.35	1.03	2.07	174.03
Sweden-N	50.22	36.36	2.05	0.48	88.62
Sweden-S	16.87	29.92	1.56	2.45	97.95
Finland	14.64	24.92	0.86	1.00	89.79
Denmark	0.00	19.51	30.02	5.16	57.86
Germany	0.00	274.61	51.90	111.78	542.73
Netherlands	0.00	47.23	67.61	27.22	149.55
Belgium	0.00	30.37	17.27	17.55	69.76
Great Britain	5.18	104.83	159.41	30.62	396.16
France	69.17	177.01	0.00	49.61	570.73
Poland	0.68	45.87	0.00	1.32	154.35
Baltic	2.51	6.67	0.00	0.08	23.25

Table 16: Average annual power balance in the countries modeled with times series for power balance.

Country	Average annual power balance
Switzerland	-12.78
Austria	0.76
The Czech Republic	7.67

A.5.2 Hydro power specifications

Table 17: Specifications for the areas with hydropower production

Area	Number of reservoirs	Aggregated reservoir capacity [GWh]	Max production capacity [MW]
Ostland	116	3555.28	2942.28
Sorost	10	40.66	26.11
Hallingdal	122	7785.87	3018.73
Telemark	55	8236.63	2312.49
Sorland	158	12449.91	4690.65
Vestsyd	90	13307.01	4186.50
Vestmidt	158	12827.23	6605.68
Norgemidt	347	9571.31	4820.73
Helgeland	87	11475.16	2781.05
Troms	107	7784.20	2099.62
Finnmark	41	852.52	418.48
Sweden-North	134	28691.92	12247.32
Sweden-South	104	4984.11	4066.19
Finland	2	5530.00	3333.00
Great Britain	3	3810.00	1227.00
France	1	9800.00	31620.00
Poland	1	1110.00	3740.00
Baltic	1	249.70	2577.00

B Results: Offshore wind scenarios

B.1 Area price

Table 18: Average area price in Norway in NOK/MWh for all scenarios

	Base	**Sor4.5**	**Sor30**	**Mid30**	**Nor30**
Ostland	313.90	263.33	91.20	27.70	33.60
Sorost	316.72	263.72	89.59	27.27	33.14
Hallingdal	307.70	258.11	89.35	27.11	32.87
Telemark	308.46	257.45	79.54	20.91	27.45
Sorland	313.61	245.21	40.29	15.96	20.94
Vestsyd	311.42	248.63	42.01	16.27	23.70
Vestmidt	307.87	256.58	85.32	16.87	24.85
Norgemidt	304.07	257.18	91.84	18.75	22.17
Helgeland	295.81	251.26	89.73	19.24	3.12
Troms	290.99	248.49	90.57	19.71	3.03
Finnmark	285.67	244.08	89.12	19.40	2.99
Norway	**305.11**	**254.00**	**79.87**	**20.84**	**20.71**

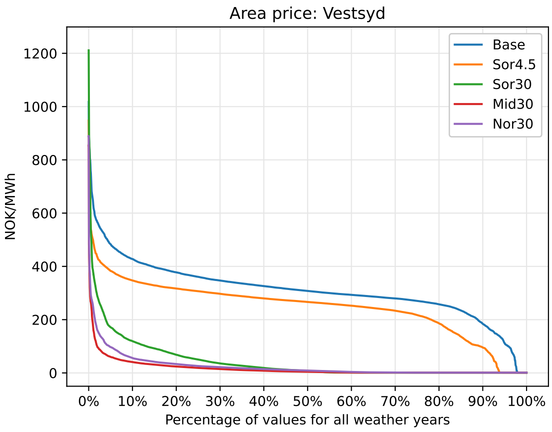

Figure 87: Area price in Vestsyd

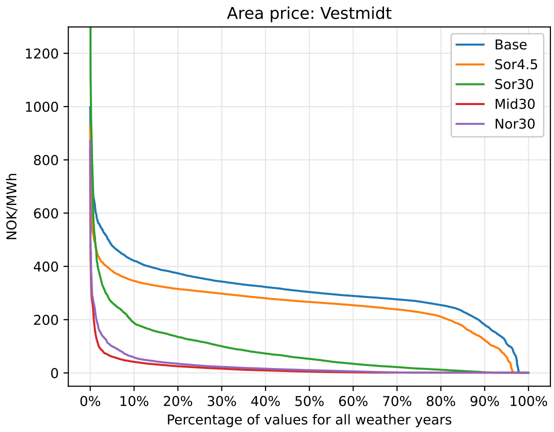

Figure 88: Area price in Vestmidt

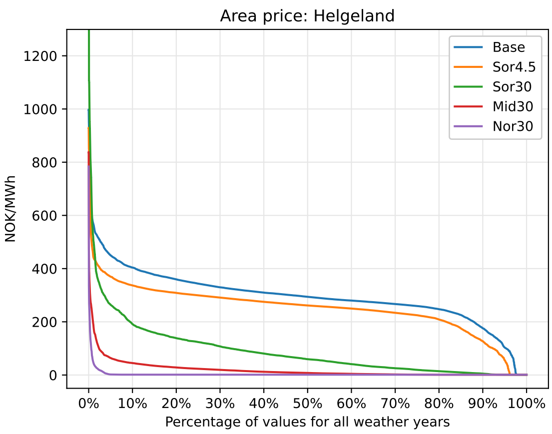

Figure 89: Area price in Helgeland

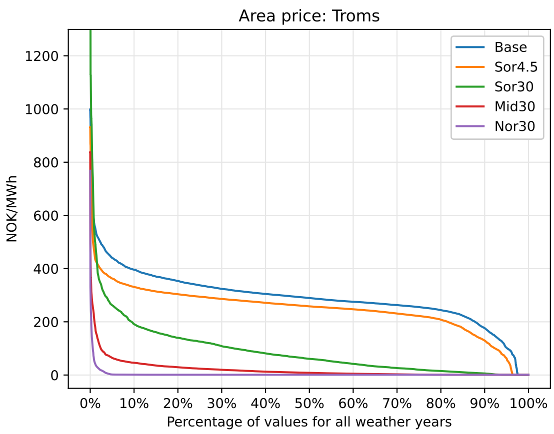

Figure 90: Area price in Troms

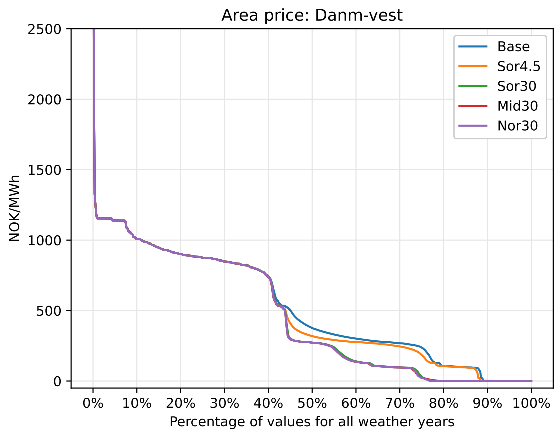

Figure 91: Area price in Danm-vest

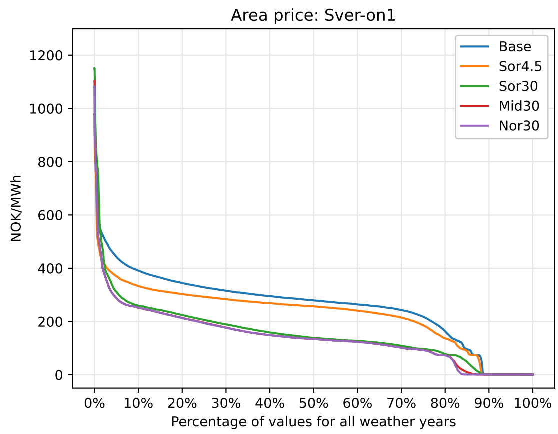

Figure 92: Area price in Sver-on1

B.2 Transmission

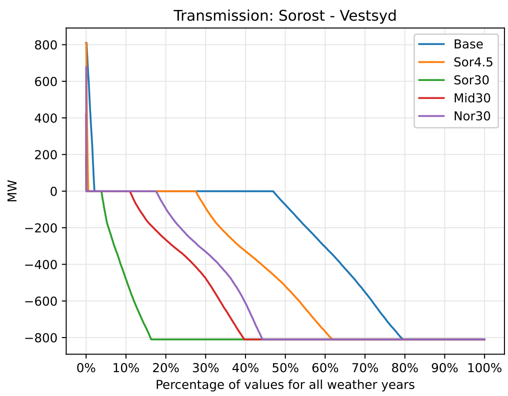

Figure 93: Power transmission from Sorost to Vestsyd

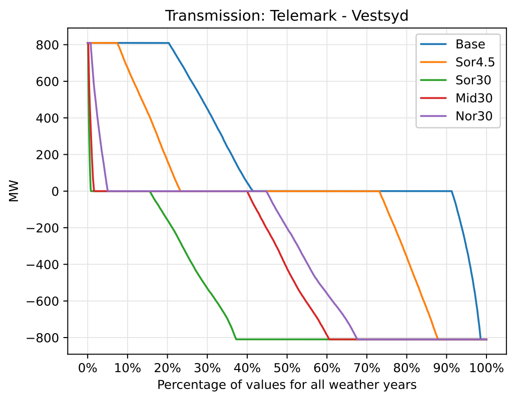

Figure 94: Power transmission from Telemark to Vestsyd

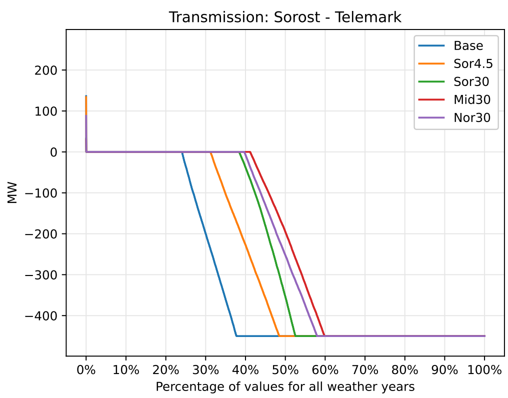

Figure 95: Power transmission from Sorost to Telemark

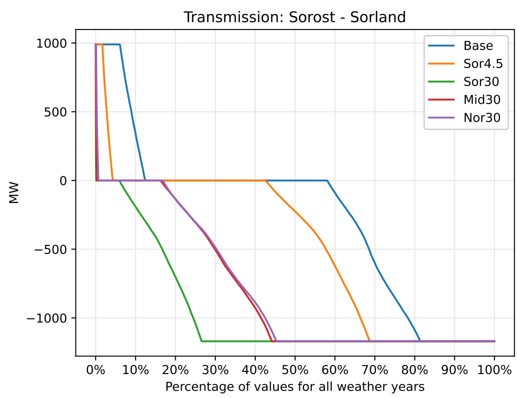

Figure 96: Power transmission from Sorost to Sorland

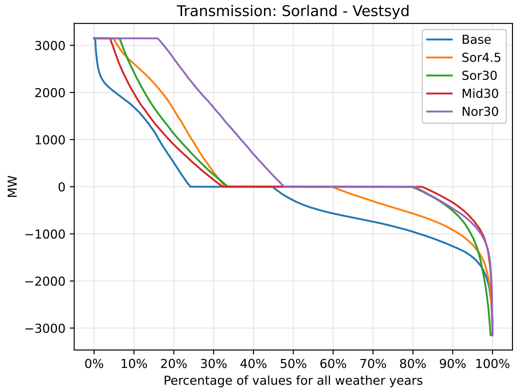

Figure 97: Power transmission from Sorland to Vestsyd

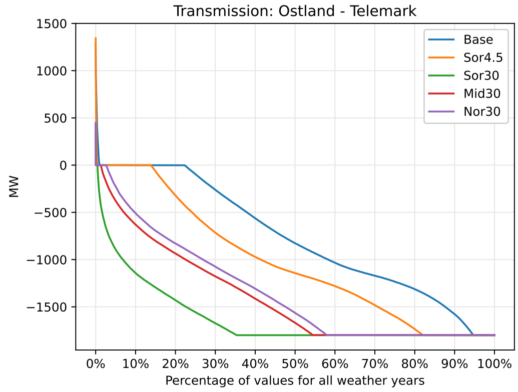

Figure 98: Power transmission from Ostland to Telemark

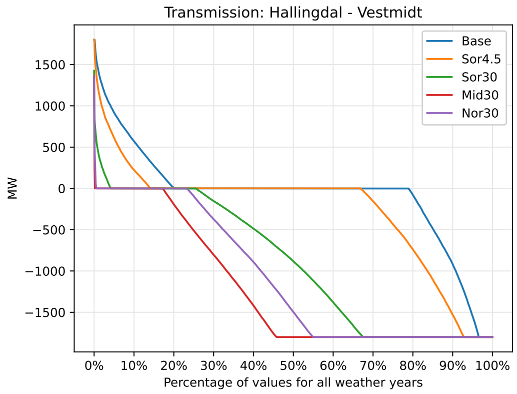

Figure 99: Power transmission from Hallingdal to Vestmidt

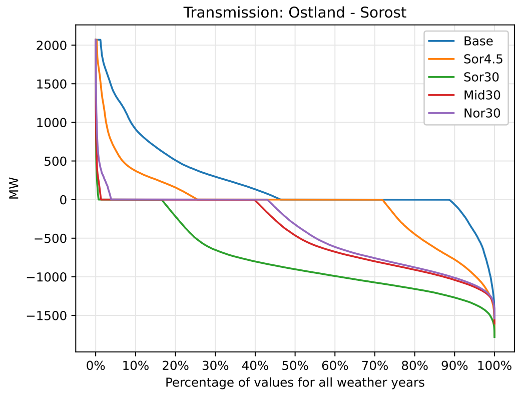

Figure 100: Power transmission from Ostland to Sorost

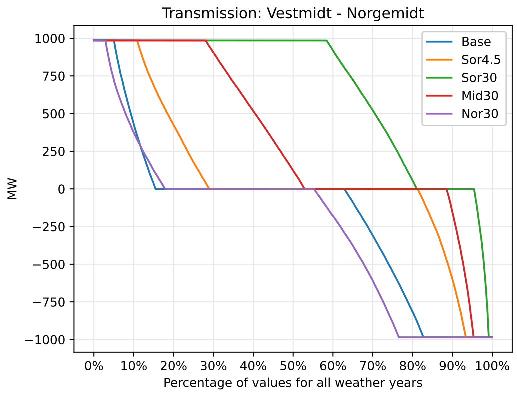

Figure 101: Power transmission from Vestmidt to Norgemidt

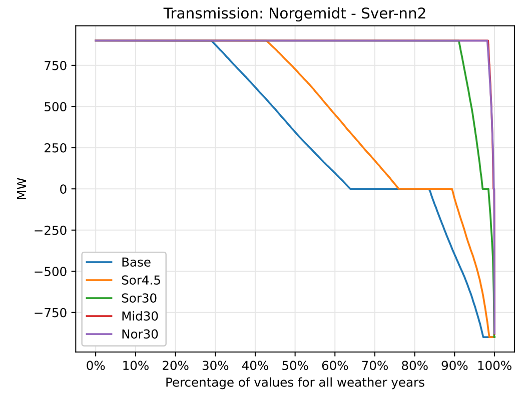

Figure 102: Power transmission from Norgemidt to Sver-nn2

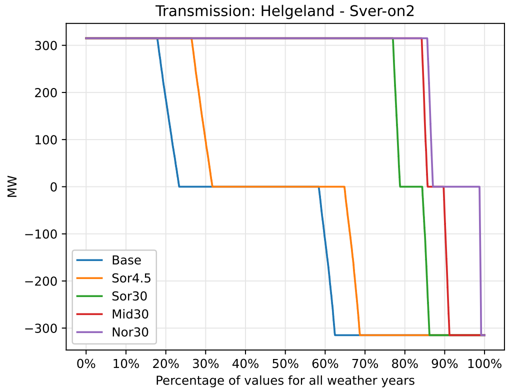

Figure 103: Power transmission from Helgeland to Sver-on2

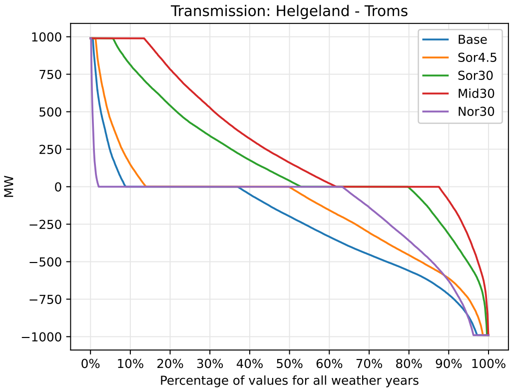

Figure 104: Power transmission from Helgeland to Troms

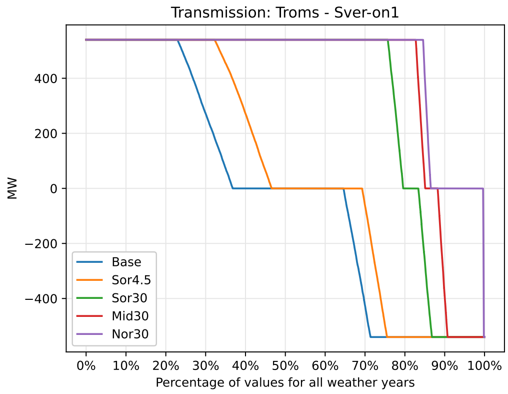

Figure 105: Power transmission from Troms and Sver-on1

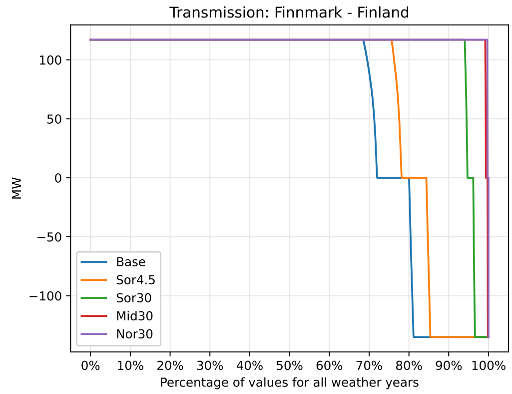

Figure 106: Power transmission from Finnmark to Finland

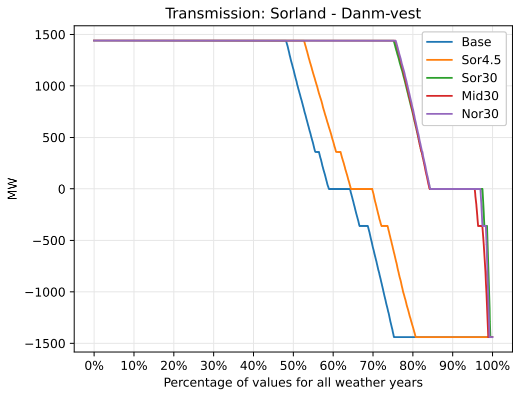

Figure 107: Power transmission from Sorland to Danm-vest

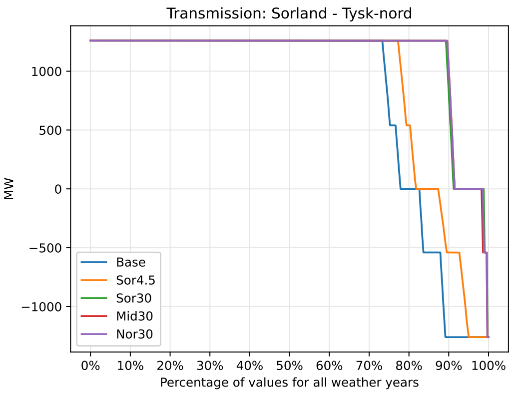

Figure 108: Power transmission from Sorland to Tysk-nord

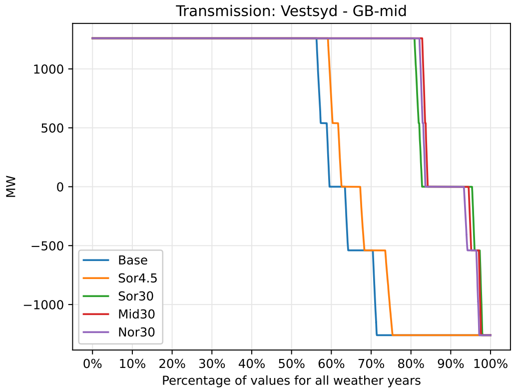

Figure 109: Power transmission from Vestsyd to GB-mid

C Results: New wind series

C.1 Wind power production

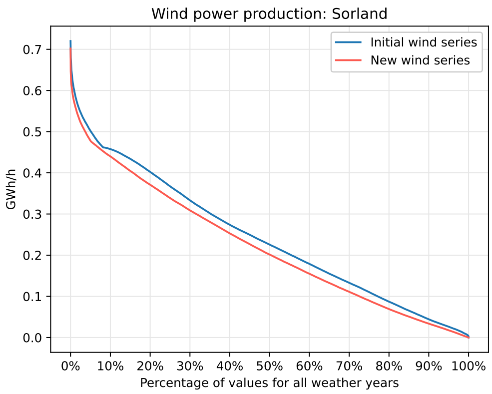

Figure 110: Wind power production in Sorland using the initial and new wind series

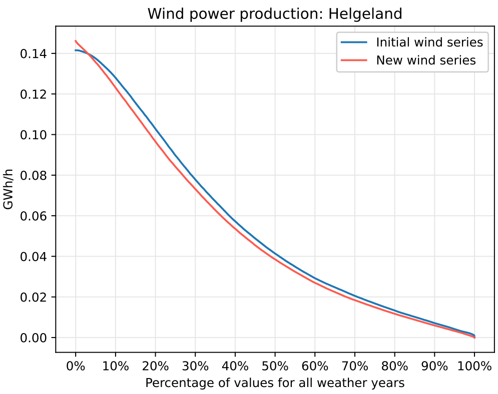

Figure 111: Wind power production in Helgeland using the initial and new wind series

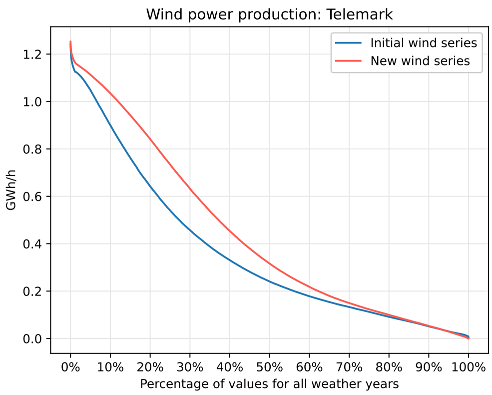

Figure 112: Wind power production in Telemark using the initial and new wind series

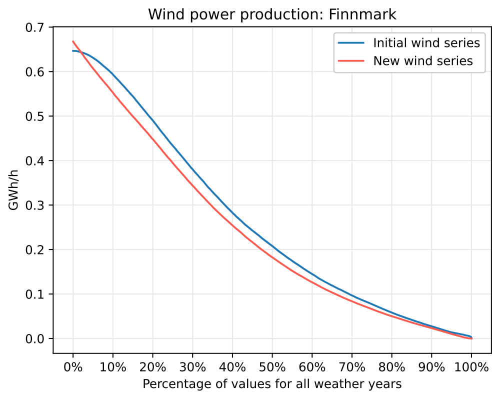

Figure 113: Wind power production in Finnmark using the initial and new wind series

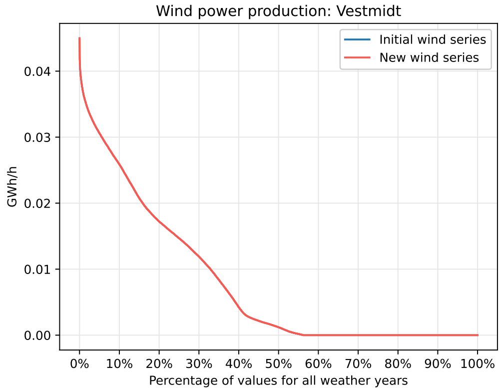

Figure 114: Wind power production in Vestmidt using the initial and new wind series

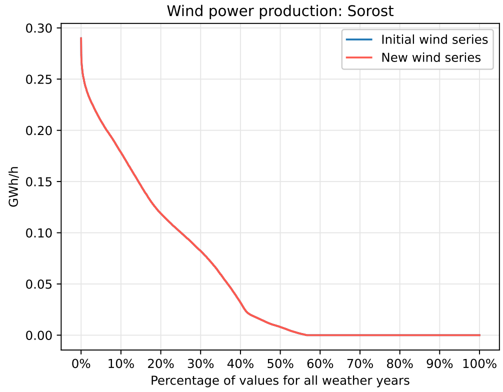

Figure 115: Wind power production in Sorost using the initial and new wind series

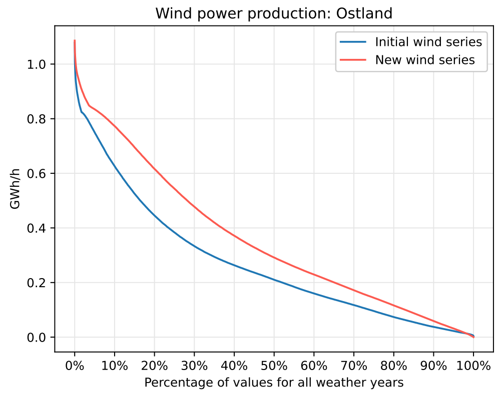

Figure 116: Wind power production in Ostland using the initial and new wind series

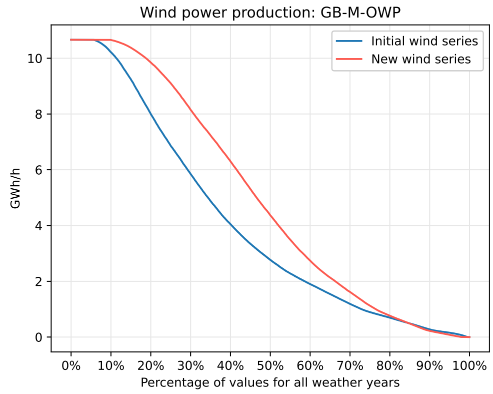

Figure 117: Wind power production in GB-M-OWP using the initial and new wind series

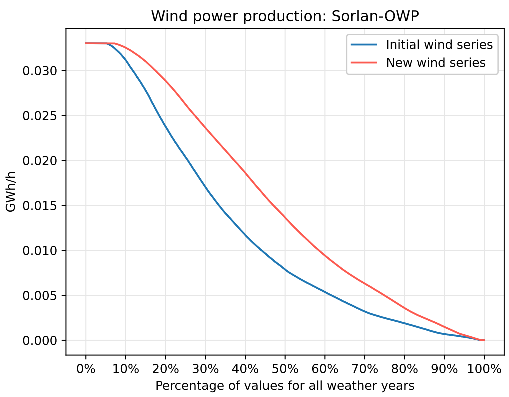

Figure 118: Wind power production in Sorlan-OWP using the initial and new wind series

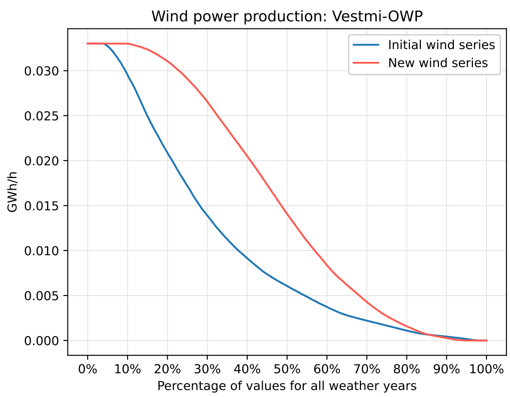

Figure 119: Wind power production in Vestmi-OWP using the initial and new wind series

Table 19: Average annual wind power production in TWh for Mid30 using the initial and new wind series

	Mid30	**Mid30-W**
Ostland	2.36	3.11
Sorost	0.47	0.47
Hallingdal	0.00	0.00
Telemark	3.15	3.83
Sorland	2.12	1.94
Vestsyd	2.31	2.08
Vestmidt	0.07	0.07
Norgemidt	9.66	10.53
Helgeland	0.48	0.45
Troms	0.45	0.39
Finnmark	2.28	2.09
Sorlan-OWP	18.96	24.53
Aegir-OWP	14.17	24.68
Vestsy-OWP	19.06	24.65
Vestmi-OWP	16.43	24.78
Norgem-OWP	14.29	24.77
Norway	**106.26**	**148.37**

Ramping

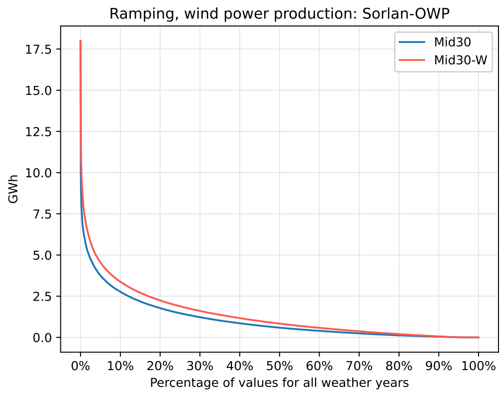

Figure 120: Ramping in wind power production in Sorlan-OWP using the initial and new wind series

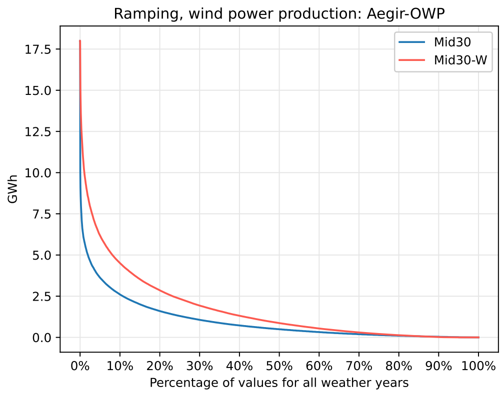

Figure 121: Ramping in wind power production in Aegir-OWP using the initial and new wind series

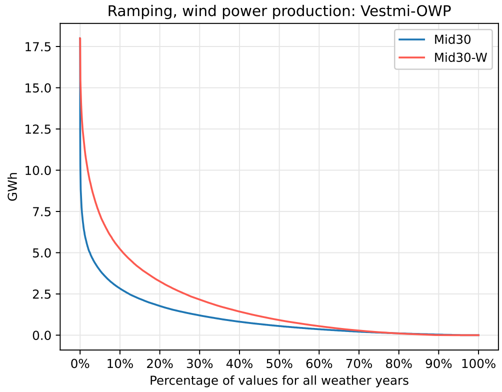

Figure 122: Ramping in wind power production in Vestmi-OWP using the initial and new wind series

C.2 Area price

Table 20: Average area price in Norway in NOK/MWh for all scenarios using the new wind series

	Base-W	**Sor4.5-W**	**Sor30-W**	**Mid30-W**	**Nor30-W**
Ostland	180.32	122.15	27.09	12.02	12.81
Sorost	181.32	121.69	26.62	11.80	12.59
Hallingdal	176.77	119.73	26.51	11.75	12.50
Telemark	176.61	118.23	19.58	6.30	7.90
Sorland	178.30	107.56	9.27	3.37	5.08
Vestsyd	177.30	109.56	9.31	3.35	5.21
Vestmidt	175.39	117.72	22.36	3.24	4.37
Norgemidt	168.18	116.64	24.87	3.84	4.10
Helgeland	148.36	105.75	21.76	3.19	1.82
Troms	145.79	104.28	21.74	3.20	1.79
Finnmark	143.29	102.55	21.43	3.15	1.77
Norway	**168.33**	**113.26**	**20.96**	**5.93**	**6.36**

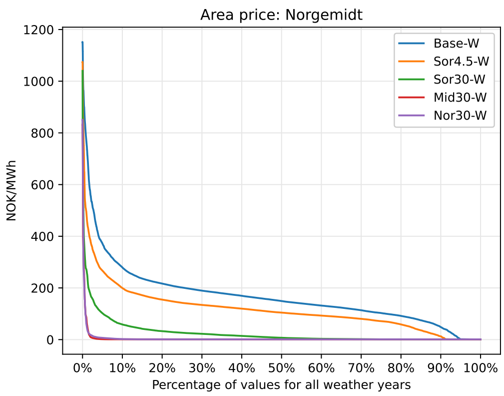

Figure 123: Area price in Norgemidt for all scenarios using the new wind series

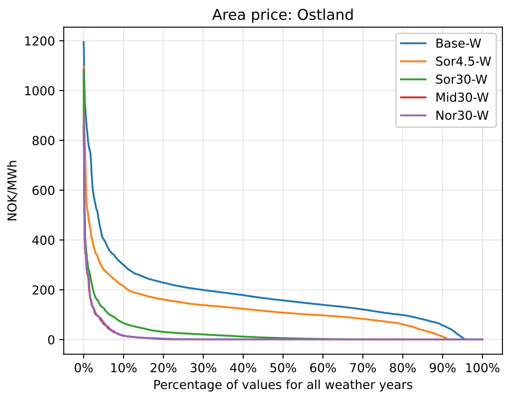

Figure 124: Area price in Ostland for all scenarios using the new wind series

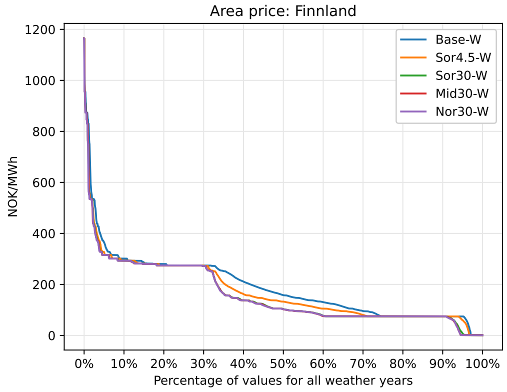

Figure 125: Area price in Finland for all scenarios using the new wind series

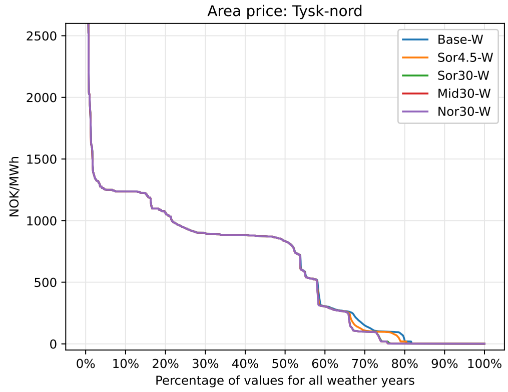

Figure 126: Area price in Tysk-nord for all scenarios using the new wind series

C.3 Transmission

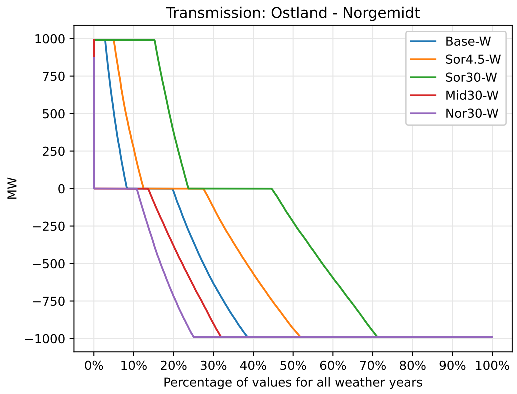

Figure 127: Power transmission from Ostland to Norgemidt using the new wind series

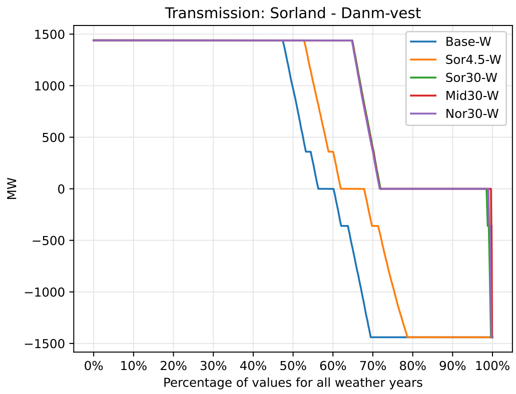

Figure 128: Power transmission from Sorland to Danm-vest using the new wind series

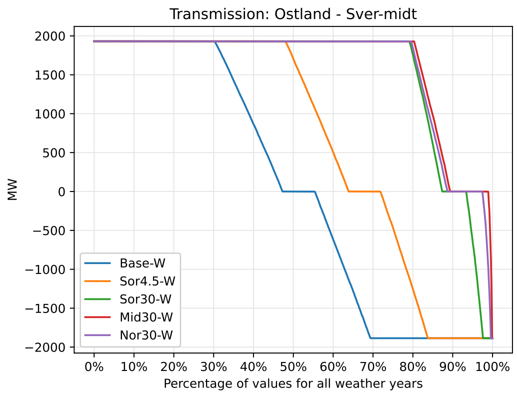

Figure 129: Power transmission from Ostland to Sver-midt using the new wind series

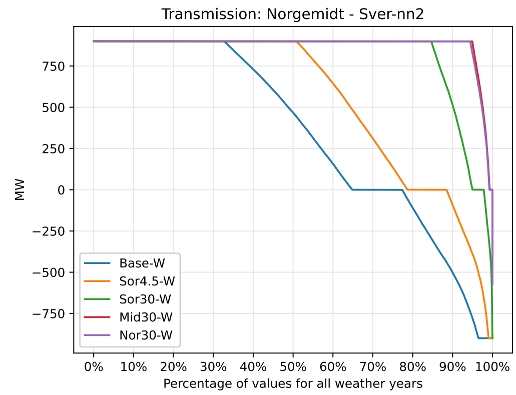

Figure 130: Power transmission from Norgemidt to Sver-nn2 using the new wind series

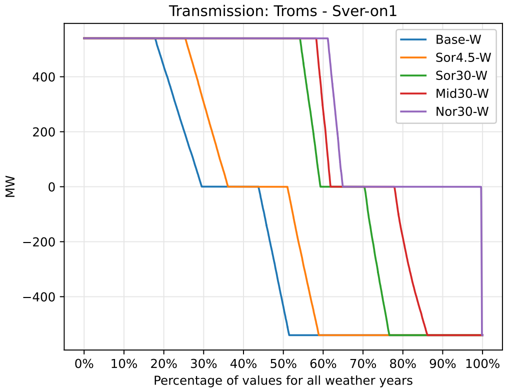

Figure 131: Power transmission from Troms to Sver-on1 using the new wind series

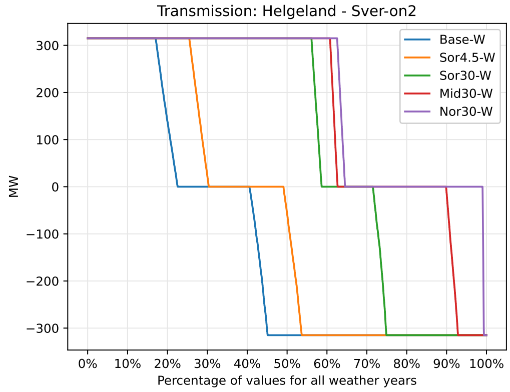

Figure 132: Power transmission from Helgeland to Sver-on2 using the new wind series

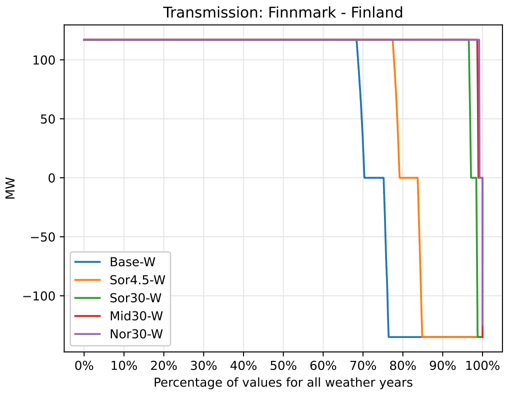

Figure 133: Power transmission from Finnmark to Finland using the new wind series

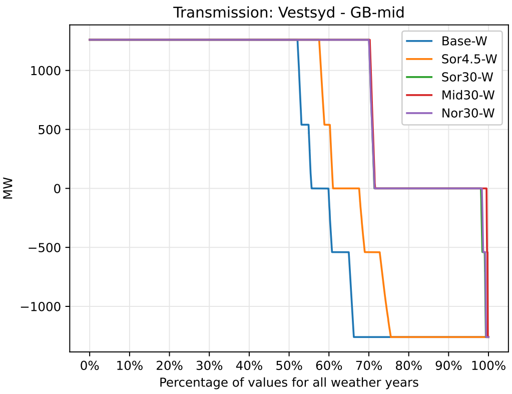

Figure 134: Power transmission from Vestsyd to GB-mid using the new wind series

C.4 Hydropower production

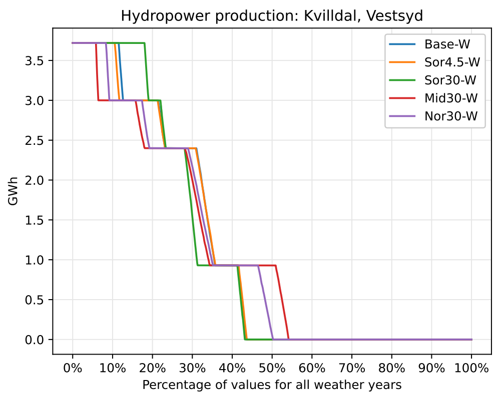

Figure 135: Hydropower production in Kvilldal for all scenarios using the new wind series

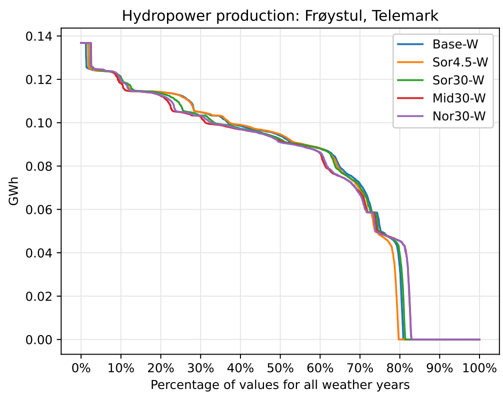

Figure 136: Hydropower production in Frøystøl for all scenarios using the new wind series

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