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Analysis of Power System Scenarios for Norway 2030 using the Fundamental Market Model FanSi

Master's thesis in Energy and Environmental Engineering
Supervisor: Magnus Korpås (NTNU)
Co-supervisor: Arild Helseth (SINTEF Energy Research)
June 2022

Master's thesis

NTNU
Norwegian University of Science and Technology
Faculty of Information Technology and Electrical Engineering
Department of Electric Power Engineering

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Norwegian University of
Science and Technology

SINTEF

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Abstract

There have been discussions about Norway's role in the European power market in the last decade. Norwegian area prices have skyrocketed in the last year due to an interconnected power system and low inflow to the reservoirs. The future is uncertain. There is expected to be an increase in energy demand in all sectors, while the aim is to be net-zero by 2050. The introduction of more variable renewable energy to the electricity mix creates the need for better optimization tools that can handle more uncertainty.

FanSi is a long-term hydro-thermal scheduling model developed by SINTEF Energy Research. It is built on a concept that uses historical records for inflow represented as scenarios to model possible future weather year scenarios. A widely used scheduling model, EMPS, uses an aggregated reservoir representation. FanSi does not aggregate reservoirs, which increases the computational time drastically. On the other hand, it better models short-term flexibility and is a model better equipped to handle uncertainty.

This thesis assesses two different aspects of FanSi. A feature investigated is the technical model and how to optimize datasets through parameters used when running FanSi. An assessment of two parameters, respectively, the number of scenarios and the number of weeks in the scenario fan, is done. The second aspect investigated is using FanSi as an analysis tool to understand the consequences of different changes to the North-European power system. The analyzed cases are high fuel prices, a high rationing price, removing the subsea cables from Norway, and increasing the capacity from Norway to Great Britain. In addition, this thesis utilizes FanSi to elaborate on future energy situations in Norway, running the scenarios presented above on Norway in scarcity and Norway in surplus situations. SINTEF Energy Research has provided the dataset used for the analysis, representing a possible power situation in 2030.

Finding the optimal parametrization is crucial when calculating water values and will mainly affect hydropower-based areas like Norway. From analyzing different parametrizations, this thesis shows how increasing the number of scenarios for all cases gives lower Norwegian area prices and better social welfare without compromising run time. Increasing the fuel prices has the most extensive significance on the North-European system compared to the other scenarios, resulting in extreme area prices and lower social welfare. Scaling up the capacity between Great Britain and Norway relieves the Northern European system of bottlenecks, resulting in higher social welfare. While prices in Norway experience a slight increase, the rest of the European areas obtain a price reduction. Removing the subsea cables out of Norway is beneficial for Norway in a surplus situation but results in extreme power prices in a scarcity situation. The results show how the subsea cables have an essential role in the North-European system, equalizing prices and functioning as a security of supply for Norway in critical periods.

Sammendrag

Det siste tiåret har Norges rolle i det Europeiske kraftmarkedet vært omdiskutert. Det har vært en enorm økning i Norske strømpriser det siste året grunnet lave vannstander i magasinene i tillegg til at Norge er koblet på det europeiske kraftnettet. Fremtiden er usikker. Det er forventet en økning i energibehov i alle sektorer samtidig som målet er null utslipp innen 2050. Innføringen av mer variabel fornybar energi i elektrisitetsmiksen gir et behov for bedre optimaliseringsverktøy som kan håndtere mer usikkerhet.

Langtidsmodellen FanSi er utviklet av SINTEF Energi. Den baserer seg på et konsept som benytter historisk værdata representert ved scenarioer til å modellere fremtidige værscenarioer. Et velkjent planleggingsverktøy EMPS benytter en aggregert representasjon av magasinene. FanSi aggregerer ikke magasin, noe som fører til en drastisk økning i beregningstiden. På den andre siden er dette en modell som er bedre rustet til å håndtere usikkerhet da modellen har en bedre utnyttelse av kortsiktig fleksibilitet.

Denne oppgaven undersøker to ulike aspekter ved FanSi. Det ene aspektet som er undersøkt angår den tekniske modellen og hvordan valget av parametere kan optimalisere simuleringen av et datasett. Det er valgt to parametere til å gjennomføre undersøkelsen. Disse er henholdsvis antall scenarioer og antall uker i scenarioviften. Det andre aspektet som er vurdert er å bruke FanSi som et analyseverktøy for å forstå utfallet av ulike endringer på det Nordeuropeiske kraftsystemet. Analysen tar for seg høye brenselpriser, en høy rasjoneringspris, fjerning av sjøkablene tilkoblet Norge og en økning i kapasiteten på linjene mellom Norge og Storbritannia. I tillegg benytter denne oppgaven FanSi til å diskutere fremtidige energisituasjoner i Norge, hvor de ulike scenarioene presentert blir kjørt på ulike datasett hvor Norge er både i en underskudds- og overskuddssituasjon. Datasettet som er brukt i analysen er laget av SINTEF Energi og representerer en mulig energisituasjon i 2030.

Å finne den optimale parametriseringen er viktig når vannverdier skal beregnes og vil i hovedsak påvirke områder med en stor andel vannkraft i produksjonsporteføljen, slik som Norge. Fra å analysere ulike parametriseringer viser denne oppgaven at å øke antall scenarioer i scenarioviften i alle tilfeller vil gi lavere områdepriser og et bedre samfunnsøkonomisk overskudd, uten å gi en drastisk økning i beregningstid. Å øke brenselprisen har den største effekten på det Nordeuropeiske kraftsystemet sammenlignet med de andre scenarioene og resulterer i ekstreme områdepriser og et lavere samfunnsøkonomisk overskudd. En økning i kapasiteten mellom Norge og Storbritannia minsker flaskehalser i det Nordeuropeiske kraftsystemet, noe som resulterer i et høyere samfunnsøkonomisk overskudd. Områdeprisene i Norge vil oppleve en liten økning mens resten av Europa får en reduksjon i prisene. Å fjerne sjøkablene tilkoblet Norge er gunstig for de norske områdeprisene i et overskuddsscenario, men vil gi ekstreme priser om situasjonen er underskudd. Resultatene underbygger hvordan sjøkabler mellom Norge og Europa er en viktig del av det Nordeuropeiske systemet ved å utjevne strømpriser og ved å fungere som en forsyningssikkerhet i kritiske perioder.

Preface

This master's thesis is written for the Department of Electric Power Engineering at the Norwegian University of Science and Technology in the spring of 2022. The thesis is written in association with the subject TET4900 Electric Power Engineering and Energy Systems, Master's Thesis. A project thesis was written by us in the fall of 2021 as preliminary work for this master's thesis. The work is conducted in cooperation with SINTEF Energy Research, who has developed the model and dataset used in this thesis.

We would like to thank our supervisor from NTNU Magnus Korpås, for his positive attitude and interest in this thesis. We would also like to thank our supervisor from SINTEF Energy Research Arild Helseth, for the great contribution with insight into FanSi and the power market.

Trondheim, 5th of June, 2022

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1 Introduction

Parts of this chapter are from the project thesis written about the same topic in the fall of 2021.

1.1 Motivation

The power system is constantly developing to support the energy transition. Some of the factors that will impact the future power system are the weather and consumption patterns. As the world aims for net-zero emissions in 2050, the share of renewable energy is increasing both in Europe and the Nordic countries. With more variable renewable sources like wind- and solar power, there will be a need for a more flexible system, also in regards to introducing prosumers into the distribution network.

Electricity production in Norway
In Norway, 98% of the power production emanates from renewable energy sources, and a large part consists of hydropower [56]. In the last decade, there has been an increase in wind power development, which at the start of 2021 contributed to 8% of the Norwegian energy production [11].

A measure that has been implemented in Norway and Sweden to increase renewable energy production is "Green certificates". Through this scheme, the goal has been to increase renewable electricity production by 28,4 TWh by 2020 and contribute to the EU's Renewable Energy Directive targets. This goal was reached in 2019 [57].

The way the "Green certificates" work is that renewable power producers can receive certificates for the electricity generated for the next 15 years. These certificates are added to the power prices, and in this way, the producers receive extra funding. The use of this scheme started in 2012 and will be continued until 2035 [47].

Electricity production in Europe
Energy production in Europe has also been through large changes over the past years. The trend is an increasing share of renewable energy. If one looks at the EU, the share of renewable energy consumption has increased from 9,6% in 2004 to 19,7% in 2019. The target for Europe is to achieve 32% by 2030 [14].

A large part of the increase in renewable energy in Europe comes from wind- and solar power. In the EU, wind and solar power made up almost 20% of the energy production in 2020, about a 2,6% rise from 2019 [1]. Both wind- and solar power depend on the weather, and an increase of these in the power production portfolio will lead to more uncertainty in power production.

When large shares of variable renewable sources are integrated into the power production portfolio, especially wind and solar, it can lead to an increase in the flexibility requirements of the system [28]. These flexibility requirements will usually be covered by hydropower and thermal energy sources like gas, coal, oil and nuclear, which balances out the fluctuations from wind and solar power [28]. This will impact the

Norwegian power market, as there is expected more connections between Norway and the rest of Europe.

Norwegian power production mainly consists of hydropower, which means water can be stored to produce power later or when needed. This makes the system able to respond to changes fast. The flexibility in hydro will become more critical as both Europe and Norway increase their share of variable renewable energy production. Norway may need to export more in the future, especially in periods of the year when wind- and solar production is low. Today, Norway has transmission lines to Sweden, Denmark, the Netherlands, Germany, and Great Britain [66]. A cause of this is the increasing significance for the power producers to calculate correct water values to produce most optimally and profitably. The importance of making the right decisions in a more complex energy system will lead to an increase in the demand for new optimization and simulation tools.

Uncertainty in weather data

Uncertainty in weather data is a challenge in long-term planning. If one looks at historical data, there can be extreme differences between the same month two years apart, or they could be pretty similar. Optimizing based on different weather data can indicate what will most likely occur in the future.

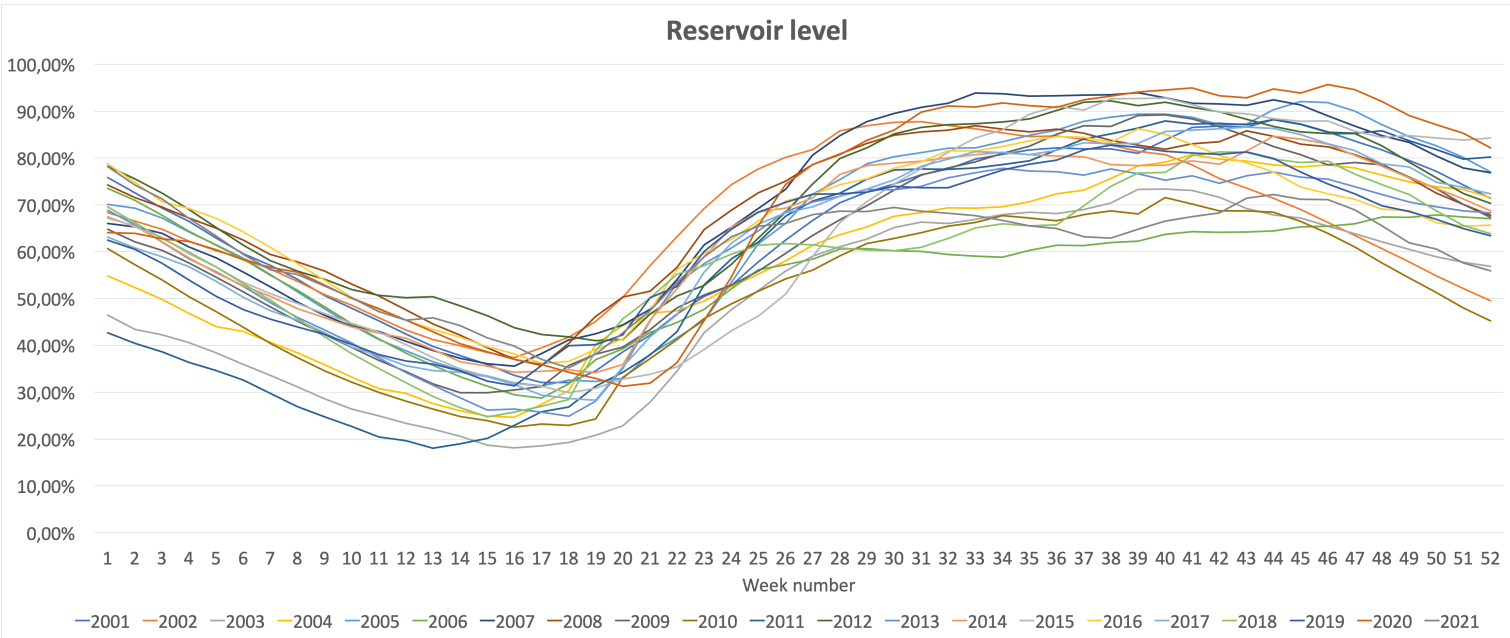

Figure 1: Reservoir level, 2001-2021
Source: [48]

Figure 1 presents percentages for the reservoir levels for the years 2001 to 2021. The numbers are from NVE [48]. As can be observed from figure 1, the reservoir levels are dissimilar for the different years. Some years the reservoir level is relatively low at the beginning of the year but ends at a high level at the end of the year. In other years the situation is the opposite. One can observe that the reservoir curves follow the same pattern each year. From weeks 1 to 17, the reservoirs are emptied, while in the period between weeks 17 to 31, a high inflow is observed. The status of the end reservoir level is dependent on the weather year. With varying inflow between weeks 17 and 31, the end reservoir levels will vary for the different years.

In figure 1 the difference in reservoir content between different weather years is shown. The content will vary with the amount of rainfall, snow, and snow-melting and the amount of energy produced. Wind and sun will also vary immensely from year to year, making it difficult to predict the amount of energy produced from these energy sources.

Climate change is happening in all parts of the world. The climate and weather will change from what has been observed the past years. An article published in 2017, [23], provides a scientific basis for climate adaptions in Norway. A few key points from this article that have an impact on the power production and power system in Norway are:

- Annual temperature will increase by approximately 4,5% °C (interval: 3,3 to 6,4% °C)
- Annual precipitation will increase by approximately 18% (interval: 7 to 23%)
- Events with heavy rainfall will be more intense and occur more frequently
- Floods induced by rainfall will increase in magnitude and occur more frequently
- Floods due to snow-melting will decrease in magnitude and frequency

The increasing energy production from renewable sources makes the power system more dependent on the weather, which means both the power production and power consumption will differ with varying weather [37]. The weather conditions in the future will give both warmer and colder climates. In addition, it will contribute to unpredictable flooding and heavy rainfall. This makes it hard to establish good prediction models to decide on the energy production strategy.

The different amounts of reservoir content and weather between different years, together with the changes expected in the future, illustrate the uncertainty in weather data and how it can be an uncertainty in long-term modeling.

Changed consumption pattern
There has been a significant increase in the number of electric vehicles in Norway in the last decade. According to SSB, 54% of the newly registered passenger cars in 2020 were electrical [64]. This shows an increasing trend and an expectation of an increase in the share of electric vehicles in the coming years. In addition, on a world basis, the fleet of electric vehicles has seen a tremendous increase, from approximately 2 million in 2016 to over 10 million in 2021 [31].

There has been and will be an increase in electrical vehicles. Besides passenger vehicles, one has also seen a development in electric trucks, boats, plains, and in general an electrification of the transport sector. This electrification can give as many as 1,5 million electrical vehicles on Norwegian roads in 2030 [63], which will lead to an increase in power consumption.

With electrification, industries are affected to transform their operations to be more sustainable. As mentioned, the transport sector will require many batteries in the transition towards electric vehicles, and the battery demand is expected to increase significantly [39]. Production factories for batteries are being established in Norway and Sweden, adding a higher demand to power production. In addition, the electrification of oil- and gas platforms will also add a higher demand to the power production requirements.

Other factors will have an impact on power consumption as well. An article written in 2017, [7], found that factors such as gross domestic product (GDP), employment rate, residential space, and the implementation of energy labeling schemes will have an impact on residential electricity consumption.

Prosumers is a term that is getting more attention. A prosumer produces power in one way or another, it can be through a solar panel on the roof or through a windmill in the garden. They use this energy for themselves or sell it to the local grid [3]. The number of prosumers is expected to increase in the future. The increase will be affected by the cost of buying solar panels and batteries, the interest in being more self-sufficient, and other factors [3].

The increase in electric vehicles will lead to an increase in power demand, while better building structures with smart technology might have the opposite effect. The prosumers will need power from the grid in some periods and supply the power system in others. This makes it hard to predict the electricity demand. It is therefore a need for a power system that can endure changes.

The amount of energy needed in the future is uncertain. However, there is expected an increase due to a rise in household income, the electrification of the vehicle fleet and oil-and-gas platforms, heat, and digitization [30].

Over the last months, one has seen abnormally high power prices in Norway and Europe. The gas prices have increased due to high demand, leading to high power prices in Europe [53]. This has led Norway to export power. At the same time, the southern parts of Norway have experienced low reservoir levels. This combination has led to abnormally high power prices, especially in the south of Norway. Today's power situation and expected trends for the coming years are discussed in part 2.4 and 2.5.

Due to all these uncertainties, there will be a need for an optimization model which can take the uncertainty of variable renewable energy, changing weather scenarios, and change in consumption into consideration, while still making accurate water value calculations.

1.2 Next generation of power market models

As discussed in part 1.1, there will be an increase in variable renewable power production, as well as a change in the weather scenarios and the consumption patterns. This can already be seen today, which is discussed in part 2.4. These changes will lead to uncertainties in both consumption and production. The EMPS model, which is widely used today, is not well suited to address all of these changes. The model will not be sufficient for future prediction and modeling as it makes too many simplifications and heavily relies on calibration [26]. As a result, there is an increasing need for the next generation of power market models. This is the main purpose of FanSi.

FanSi
FanSi is a long-term hydro-thermal scheduling model (earlier named SOVN) developed by SINTEF Energy Research. The project with developing the model (SOVN) started in 2013 and ended in 2017 [26]. The project aimed at creating a new fundamental hydro-thermal market model with a detailed representation of the hydropower system and was founded by the Research Council of Norway, Statnett, Statkraft, BKK, and NVE [26].

The model is built on a concept that uses historical records for inflow to represent future uncertainty. It is a model which combines optimization and simulation, referred to as a *scenario fan simulator* (SFS) [26]. The difference between the EMPS model and FanSi, is that in FanSi the reservoirs are not aggregated to one large imaginary reservoir. The water values are calculated directly for each individual reservoir. This leads to a drastic increase in the computational time needed, which is the main drawback of the model and prevents operational application. Another conclusion from an article that studied both EMPS and FanSi is that FanSi has a superior representation of constraints and possibilities for the future power system [18]. A more in-depth explanation of the working of FanSi is presented in part 4.

FanSi is not taken in operative use but has been used by SINTEF Energy Research for research purposes. The model is a prototype and, therefore, may have weaknesses. FanSi has characteristics that make it more interesting than the EMPS model. It is known to better handle the uncertainties that variable renewable energy production brings into the planning process. An investigation of which parameters are optimal for different datasets has not been assessed. In this thesis, the model will be run with different parametrizations for the same datasets to see if one can conclude which settings are most optimal.

1.3 Objective

Power market models are essential tools to analyze and understand how different scenarios affect the North-European power system. Many uncertain parameters need to be decided when modeling. The objective of this master thesis is divided into two parts. One part looks at the technical model and how to best optimize different datasets through the parameters used to run FanSi. The other part looks at how the North-European power system, especially Norway, is affected by different scenarios. The simulations are based on how one thinks the power situation can be in 2030. There will be done simulations with high fuel prices, a high rationing price, both removing the subsea cables from Norway and increasing the capacity to Great Britain, in datasets where Norway is both in surplus and in a scarcity situation. The scenarios are inspired by the happenings in the power market in the last years and expected future trends. How will the prices in the market be affected by the different scenarios? There will also be looked at how different parameters in FanSi affect the results and the computation time of the model. Will this differ in the different scenarios, or will one parametrization have the same impact on all?

The thesis will focus on three different research questions:

- Which parametrizations are optimal when running FanSi and will this vary for different scenarios?
- What is the significance of changing fuel prices and the capacity of subsea cables connected to Norway?
- How does these results differ when Norway is in a scarcity- or a surplus situation?

1.4 Description of the conducted work

In this thesis, the students were given a base dataset from SINTEF Energy Research. Together with Magnus Korpås and Arild Helseth one decided which scenarios were to be created from this dataset. The students further made the necessary changes to the dataset to obtain these scenarios. The simulations were run using an external server through SINTEF. The results were extracted, formatted, and analyzed using Python.

1.5 Structure

This master's thesis contains thirteen different sections. The first section contains the motivation for the thesis, the relevance of FanSi, the objective description, the conducted work, and the structure of the thesis. This section tells what will be investigated and how the thesis is built.

The second section consists of information about the North-European power market, interconnections, today's power situation, future trends, and relevant studies. This chapter gives the reader insight into how the system works and lays the groundwork for why the thesis has chosen the specific topic and what the scope is.

The third section includes theory that is relevant for the results and discussion of the thesis.

The fourth section tells about the optimization and simulation program, FanSi, used to obtain the results presented later in the thesis. This section shows how the model works and some of the most important assets for this thesis.

The fifth section contains information about the base dataset used and the specifications made. It contains a description of the system simulated.

In the sixth part, the different scenarios and parametrizations that are used in this thesis are described. It presents the scenarios and explains the changes which are made and why they are chosen.

In the seventh section, the results from investigating the effect of the different scenarios presented in part six are presented and discussed. The factors looked at are social welfare, area prices, transmission, reservoir level, and recalculation of end water values.

In section eight, the results for investigating how the different parametrizations affect the simulation are presented and discussed. In this part, the scenario reduction algorithm, social welfare, area prices, reservoir levels, and model run times are assessed.

Section nine presents three different datasets, where Norway is both in surplus and scarcity. It is also described different scenarios and parametrizations which will be run on these datasets.

Section ten presents and discusses the results for the scarcity and surplus situations, both looking at the results between the cases and parametrizations. To compare the datasets, area prices, reservoir levels, and the power situation are presented and discussed. For the parametrization part, the social welfare, together with area prices and run times, are used.

In section eleven, a conclusion regarding the objective of the thesis is presented.

Section twelve describes what further work can be done based on this thesis.

Lastly, the Appendix in section thirteen shows some relevant information about the system inputs and more results from the simulations.

2 The North-European power market

Parts of the text in this chapter is from the project thesis written about the same topic in the fall of 2021.

2.1 The North-European power system

Through cables, the countries in Northern Europe are connected to a common power system, which opens for trade of electricity. The balance of supply and demand is fundamentally different for each European country [49]. In Norway, a large share of energy production comes from hydropower. For Denmark, wind constitutes a large part of the electricity production, while in Sweden and Finland, a high share comes from thermal production[49]. Seasonal differences and weather affect renewable power production, leading to times when trading is beneficial for countries. At times with snow melting and high precipitation, it can be profitable to export power from Norway. When electricity production from wind is high in Denmark, the prices will be low, and it will become profitable for other countries to import. When Norway imports power from other countries, the water in the reservoirs can be saved for later when the water value is higher. The difference in price between two countries will tell if the country can benefit from export or import in a given hour [49].

Today, Nord Pool is Europe's leading power market [42]. It was established in 1993 for the Norwegian electricity market and extended to include Sweden in 1996 [69], making it the world´s first multinational exchange market for electricity [69], which now markets across 16 European countries [42].

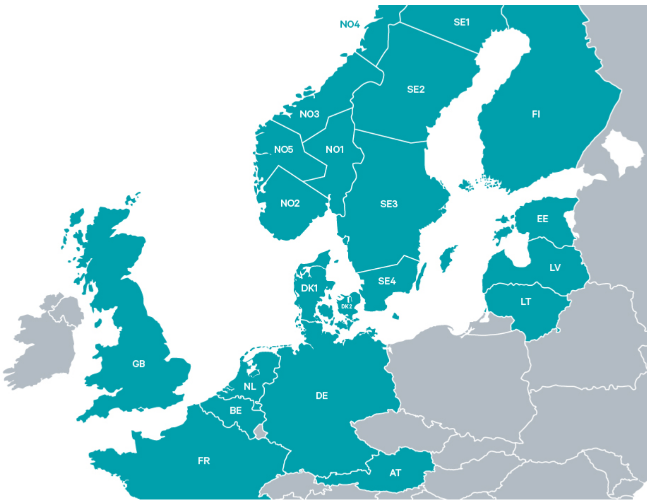

Figure 2: The bidding areas, Nord Pool
Source: [35]

The power market is divided into different bidding areas, where Norway is divided into five areas, Sweden into four, Denmark into two, and Finland constitutes of one [43], which can be seen in figure 2. Since the transmission capacity on the lines can lead to congestion for the power flows between the different bidding areas, the area prices can differ [43].

The day-ahead market
The day-ahead market is the main market power place. The energy for the next 24 hours is bought and sold in this closed auction [44]. When the deadline at 12:00 CET passes, all the purchase and sell hours are combined into two curves for every delivery hour [44]. The prices are calculated for every hour, with one aggregated demand curve, and one aggregated supply curve [69]. Here, the bidding area and the different block orders are anonymous. For each delivery hour, the area and system prices are calculated with the goal of maximizing social welfare [44].

Intraday market
The prices for each hour and each bidding zone for the next day are set in the day-ahead market. The intraday market works together with the day-ahead market to secure the balance between supply and demand as one can trade closer to real-time in the intraday market [45]. Unlike the day-ahead market, the market is open for trading around the clock until one hour before delivery [69]. The intraday market gives the participants a possibility to take outages and unexpected changes to the consumption into consideration [45], and this functions as an aftermarket to the spot market [69].

2.2 Interconnections

With connections to other countries in Europe, one gets the chance to import when the external power prices are lower than the internal, and to export when the external prices are high [38]. When Norway is having a dry year, imports can be beneficial, and when there is a wet year exporting gives an economic surplus. With interconnections, the power price variations are also reduced [38].

The effect of Norway exporting power is a part of making the energy production in the rest of Europe more renewable and flexible [17]. If more variable renewable energy is built and installed, for example, solar and wind, there can be used less fossil energy like coal and gas. The problem is that when there is little wind and solar production, there is a need for more energy. Norway can be a part of submitting this flexibility. An example is the connection between Germany and Norway. Germany wants to phase out more of its coal-fired plants and is large on wind [40]. On windy days, they produce enough to export their excess power [40]. Norway can then use this excess wind power and save water in the reservoirs for when the production is needed and instead export when there is an abundance of water in the reservoirs [40]. As mentioned before, Norway has a lot of renewable hydropower, which is cheap during peak demand. The Netherlands, on the other hand, has plenty of thermal power plants, useful for base load [32]. Between these countries, it can be beneficial if Norway supplies the Netherlands during peak hours and the Netherlands Norway with cheap energy for base load or energy to pump water back into reservoirs [32].

Historically the interconnections between countries in Europe are established to achieve security of supply [32]. Later, the interconnections have been vital in solving two challenges. The interconnections are important when liberalizing the electricity market and creating an Internal Electricity Market where one would achieve competition, trade, and hopefully an increase in overall welfare and lower electricity prices [32]. Another challenge is the integration of the increasing amount of renewable energy in Europe, which has been built in the last couple of years and which will be built in the years coming [32]. This increase leads to an increasing amount of possible synergies between different systems [32], and therefore requires cross-border transmission capacity.

The primary reason for establishing interconnections between countries is to reduce the economic costs of supplying electricity compared to having no interconnections [8]. Trading energy between nations can give a significant economic benefit but will also come with financial outlays [8]. In an interconnected system, one wants all the parties to benefit. This requires careful consideration when pricing the traded electricity [8]. Since it is expensive to build these interconnections, thorough investigation and planning should be done beforehand, and only interconnections which increase social welfare should be carried out [49].

2.3 Rationing price

At times, a situation may occur where there is not enough energy available and where producers cannot cover the firm demand. As mentioned earlier, hydropower production is dependent on inflow, and in dry years the situation may become critical. In events where there is not enough energy available, prices will rise to very high levels, and it is in the producer's interest to have power to sell at these prices.

The rationing price equals the social-economic cost of involuntary demand reduction [9]. Reasons for rationing are that the reservoirs are emptied, lack of generator capacity to produce enough power, and bottlenecks in the distribution system. The societal cost of rationing in the producer's decision-making is not a known or common price. The typical price used in the models is 20-30 NOK/kWh [9]. These values are low compared to international estimates which range between a few €/kWh to about 45 €/kWh for private end-users and up to 250 €/kWh for the industrial and commercial sector [59].

Value of lost load (VOLL), is the value that consumers put on un-supplied electricity [2]. It is an established measure of valuing what an average consumer puts on one MWh un-supplied power [2]. It can be discussed if this can be used as a measure for rationing price. However, rationing has other consequences affecting society and is therefore not easy to quantify. There is little theoretical insight into how one should determine the rationing price. On the other hand, the rationing price may significantly impact the water values and as a result, also the reservoir disposal, which is the conclusion of the master thesis "Svært anstrengte kraftsituasjoner" [71]. Therefore the users of power market models should be aware of the impact of the rationing price.

A consequence of rationing is, as mentioned, an involuntary reduction in demand. The authorities of rationing may intervene in regulating production to secure the society's needs. In this case, energy is prioritized concerning health and life, vital interests of society and business. Rationing is assumed as the worst-case scenario and must be avoided. Simulations from the master thesis [71] shows that if the price elasticity does not increase when power prices are extreme, one must accept high power prices to avoid rationing.

2.4 The power situation today

As this master thesis is being written, Norway and Europe have, during the fall of 2021 and is still at the beginning of this year, 2022, experiencing very high power prices. The price growth in September of 2021 has been the highest seen in the last five years [34]. Headlines about the high power prices were not a rare sight in the newspapers in 2021 and the start of 2022. This is the complete opposite of the situation the year before, September 2020, when the reservoirs were overflowing, and at times the power prices were below zero [22].

There are many reasons for the situation of seemingly high prices today. Norway is highly reliant on hydropower as it stands for 90% of the Norwegian power production. Therefore, the amount of water in the reservoirs directly impacts the power price. The reservoir levels were abnormally low in the fall of 2021, which is usually a time when they are pretty full due to snow melting in the spring and rain during the summer and into the fall months. There has been little rain and snow, which has led to low filling of the reservoirs [22].

Through cables, Norway is connected to the European power market and can export power to Sweden, Denmark, the Netherlands, Germany, and Great Britain [66]. These interconnections lead to a globalized market. Therefore, the Norwegian power market is not only dependent on its energy situation but also the state of other countries. The current European power prices are higher than the ones in Norway [22], which is related to the high gas prices [4]. Since the power is exchanged in a shared marketplace, this results in the export of power even though the reservoir levels are low, which pushes the prices even higher in Norway [22].

This difference in the price and power situation between the same periods one year apart shows the vulnerability and insecurity one gets in the power system when it is highly reliant on renewable energy sources. The importance of good planning and an optimization tool that can consider different scenarios is increasing.

In February 2022, Russia invaded Ukraine. This has led to a decrease in the import of oil and gas from Russia, which can partly be covered by gas from the Middle East and the US, but will most likely be far more expensive [29]. At this time, end of March 2022, the US and Great Britain have banned the import of oil and gas, while the EU is considering doing the same [6]. The increase in oil and gas price will most likely have a lower effect on the power prices in Norway than further south in Europe, where they are more reliant on gas [29]. Norwegian power prices are more affected and closer linked to the prices in the rest of Europe than before, which means the situation also influences the power prices here [68].

2.5 Future trends in the North-European power market

This part about the future trends in the power market is based on Statnett's "Kortsiktige markedsanalyse 2021-2026" [5] and NVE´s "Langsiktig kraftmarkedsanalyse 2021-2040" [4], which describe tendencies one can expect in the power market in the years coming. While Statnett´s report focuses on the next couple of years, NVE has chosen a long-term approach to the trends until 2040. The analysis mainly focuses on the developments of the Nordic region but also considers changes in the European system [5].

The European power system is constantly experiencing changes, and some of these developments will have a long-term effect on the power system [4]. EU has decided to raise the emission target for 2030 [15], which has led to an increase in the CO_2 price and, in addition, influenced the Norwegian and European power prices [4]. The Norwegian power prices have also experienced an increase as a cause of more connections to Europe, where the latest additions to Germany and Great Britain have made the Norwegian power prices more vulnerable to the prices in Europe [4].

Production, consumption and capacity
In the Nordic area, both the power consumption and renewable power production are expected to increase, which is expected to lead to a stable power surplus in the market [5]. In the future, Norwegian consumption is expected to surpass production. By 2026, Statnett's short-term analysis, [5], predicts that the surplus seen today will be non-existent. This is supported by NVE's long-term analysis, which expects the Norwegian surplus to be reduced towards 2030, but then again increase towards 2040 [4]. The increase in consumption is mainly due to electrification projects, including the electrification of the petroleum industry and an increase in electric vehicles. There will be a drastically higher amount of power production reliant on the weather, and as a result, this induces difficulties in optimizing production planning.

As the world is moving towards more variable renewable energy sources, a rise of both on- and offshore wind production is foreseen in the Nordic countries [5]. Finland is expected to triple their wind production over the next five years, Sweden will increase its production, and Denmark is expected to increase their wind production by 50% [5]. On the other hand, Norway is an exception among the Nordic countries, as the increase in wind power production is expected to diminish in 2024 when the planned developments are completed [5]. However, it is expected to be built new wind production units both on- and offshore in Norway after 2030 [4]. The assumed future wind power production will together make up around 40 TWh, which coincides with the expected increase in power consumption towards 2026 [5].

In addition to wind energy, solar energy is another variable energy source. The future cost of installing solar power is expected to drop [4], and the installed effect is expected to go from around 2 GW today to around 8 GW in 2026 [5]. Solar power production is at its highest in the summer, while the consumption is at its lowest, which again leads to more export out of the Nordics during this time. The increase in solar power production will not highly affect the power production in the winter but can have a noticeable effect in the spring. The difference with solar compared to other power sources is that the market is dominated by other actors than usual, like house owners, owners of bigger buildings, and landlords, which might lead to the need for other incentives [4].

The balance between availability, controllable production, and firm consumption has weakened in the last years [5]. The power balance in the Nordic will continue to weaken going forward as the rise in consumption will largely be covered by wind power production [5], which is highly reliant on the weather. Historical weather data shows there can be long periods with little wind and cold temperatures in the winter, which can simultaneously occur both in the Nordics and the North of Europe [5]. Having a power production portfolio reliant on wind energy during these periods can become problematic, and an investment in other solutions must be made. The electrification of Europe makes society more dependent on a stable and secure power supply. From NVE's analysis, it is found that in 2040, periods with high demand will coincide with periods with little wind and solar [4]. This is one of the challenges the new power system will need to accommodate and one of the challenges which needs to be solved. There is a need for more flexibility, where one idea is hydrogen and batteries. The Norwegian hydropower is expected to help with achieving flexibility in the power system. There are done studies on this which are elaborated on in part 2.6.

The capacity between the Nordic countries and Europe is expected to increase. In 2022 the exchange capacity in and out of Norway will be around 9000 MW [5]. The capacity out of the Nordics will increase when connections between Denmark and UK, and Sweden and Germany become active by 2023 and 2025/2026 [5]. Uncertainty in the availability of the connections to the Nordics are bottlenecks north in Germany. Today, Norway has net export on the cables to Germany and the Netherlands in an average year [4]. As the European power market evolves and the power production becomes more renewable, Norway is expected to import not only when the energy situation is scarce but also when other countries can offer inexpensive power from wind and solar resources [4].

An observation is that many countries in Europe will have problems with meeting their target on onshore wind power, which increases offshore wind production planning [5]. The cost of building offshore wind has decreased, and together with the increasing carbon price and a higher ambition to cut emissions, it can lead to more offshore wind even without subsidies [5].

Power prices
The analysis done in [5] shows that the future power prices will be lower compared to the high prices seen in the last months. The decrease will be caused by coal- and gas prices returning to more typical historical values [5]. The power prices will still be high as the CO_2 prices will continue to increase [5]. From the analysis done in [4], it is expected that the power prices in Europe will be at a higher level in the coming 20 years compared to the levels seen in the last decade. This is highly affected by the expectation of a higher CO_2 price which makes fossil power production more expensive. As a result, neighboring countries with connections to areas with fossil production will also experience higher prices. Based on NVE's analysis, gas will still stand for about 15 percent of the power production in 2040, which means the CO_2 prices will still affect the power prices. The increase in renewable power production will, however, contribute to more hours with low power prices and seemingly reduce the impact of the CO_2- and gas prices on power prices [4].

When the world economy reopened during the pandemic, the demand for gas skyrocketed, which led to high power prices in Europe [53]. The increase in gas price pushed the coal price up as the resource was cheaper, leading to high CO_2 emissions per MWh and high demand for CO_2-quotas. This again pushed the CO_2-price up [5]. The expectation is that the fuel prices will normalize in the years coming [5]. On the other hand, there is an assumption of an increasing gas price towards 2040 as demand is expected to increase in Asia when the economy develops [4].

The CO_2 price has more than doubled the last year, driven by the EU's emission targets and the increased demand for quotas following more coal production [5]. By 2030 and 2050, there is planned a decrease in emissions, and therefore the CO_2 price is expected to continue to rise [5]. The increase in CO_2 price will have a significant effect on the profitability of renewable power production [5]. This will lead the power prices to be very low in some hours, while CO_2 and fuel prices are expected to increase the price variation in others [4].

The increase in renewable variable energy sources like wind and solar, which are reliant on the weather, higher CO_2 prices, and a tighter effect balance will lead to more price variations in the power prices[5]. Another factor that can lead to price variations is bottlenecks between the north and south of Germany. More unregulated wind and solar power are being built in the north region. On the other hand, the south region has a high industrial consumption while the thermal power producers are being phased out. There have been significant differences in the power prices between the south and the north of Norway. These differences are still expected in the future, but as a cause of future expansion plans on the connections to Sweden, a decrease towards 2040 is foreseen [4]. Coal power plants are being phased out in Europe [13]. To avoid scarcity situations, this should be done gradually in time with more renewable production, more capacity for import and export, and more flexible solutions [5]. The expansion of renewable power production relies on a quick and comprehensive development of the power system both in and between European countries [4].

In this thesis, there is used a dataset that represents a possible scenario for 2030. There is also done changes to the production and consumption to make other power situations. One can find other cases made on how the system may look in the future.

One example is Statnett's long-term market analysis, [65]. In this scenario, they predict that the consumption will increase from around 140 TWh today to around 185 TWh in 2040, while the production will increase to 193 TWh in the same period. NVE's long-term market analysis, [4], predicts slightly smaller numbers, with the consumption increasing to 174 TWh and the production to around 185 TWh.

The HydroCen report, [58], from 2019, which is the basis for the dataset used in this thesis, predicts a scenario where the production is around 153 TWh and the consumption around 136 TWh in 2030.

All the scenarios have a noticeable increase in both production and demand in Norway towards 2030 and 2040. The statement corresponds with most market short- and long-term analyses. This thesis uses a base dataset where the production in Norway is around 172 TWh, and the consumption lies at 137 TWh. The consumption is almost similar to the HydroCen scenario, while the production is higher. There will also be made a dataset where the demand in Norway is increased to 200 TWh, while the production is kept at 172 TWh. This creates a dataset where Norway is in a scarcity situation, which links with Statnett's short-term market analysis, [5]. The last change done to production and consumption is a dataset where the demand is kept at 200 TWh, and the production is increased to 245 TWh.

2.6 Relevant studies

This thesis analyzes the North-European power system in terms of power prices and social welfare. These analyses are done using scenarios based on assumptions about the future power system. Similar studies have been conducted to investigate hydropower as a flexible resource when variable renewable energy sources are implemented in Europe. In this thesis three articles, [36], [33], [20] and a PhD, [19], are used to elaborate on previously established results.

The articles "Integration of offshore wind power at Utsira Nord and Sørlige Nordsjø II" , [36], and "On the profit variability of power plants in a system with large scale renewable energy sources" , [33], use datasets with a 2030 perspective. While the first article investigates integrating offshore wind power to hydropower-based areas, the second looks at the profitability of hydropower as a flexible resource. The results from the first article are that with the addition of an offshore wind farm, the total price level is lower compared to the reference scenario in article [36], and that more variable production gives more variable prices. These results are based on using the following prices 70 \$/t, 20 EUR/MWh, 30 EUR/t and 70 EUR/t for coal, gas, biofuel and CO_2, and excluding the investment costs of offshore wind farms. The analyses are done to what is considered "normal years", and for wet years it is observed more frequent price dips at zero-level when the wind farm is connected directly to Sorland. In the research, the placement of the offshore wind farm is found to impact the prices in both Denmark and Norway. The addition of wind power plants lowers the producer surplus and increases the consumer surplus as a result of lower prices. The article also mentions that the contribution of energy from wind will reduce energy shortage in the driest years and, as a result, reduce the risk of rationing.

The results from the second article show that variable energy sources increase the short time volatility, which reduces the profitability of several plants due to the "merit-order-effect". When wind power production is high and solar power production is low, the system experiences more price spikes in the winter season. The profitability of gas and coal-fired plants correlates to the variable annual production of renewable energy sources. Wind power production has a significant impact in regards of profit. The variation of the annual profit of wind power plants, around +/-10% to +/-5%, induces a risk for investors.

The third article, [20], studies the power balance in the Central-West European system in 2050 with high shares of solar and wind resources. The assessment uses FanSi and EMPS with weather data from 58 historic years for the European system. The study shows how Norwegian hydropower can function as a flexible resource to balance the European system. The research presents cases of rationing and high volatility in power prices as a result of renewable energy sources. Nevertheless, hours with involuntary shedding of demand in peak load hours reduce with Norwegian hydropower. The analysis has a prerequisite of increasing the Norwegian hydro production capacity by 30 GW. The average annual power prices decrease by 10% in all the simulated cases when increasing the Norwegian hydro production capacity by 11 GW. A reduction of 5% of the demand gives the same result.

The research emphasizes the importance of pumping possibilities to utilize the higher production capacity fully. The analysis also points out that FanSi gives higher price reductions with increased Norwegian hydropower, as it handles short-term flexibility and takes variable wind- and solar production into account.

The Ph.D. "Balancing of wind and solar power production in Northern Europe with Norwegian hydropower" published in 2018, [19], investigates Norway's possible role in balancing large-scale renewable power production in Europe in the future. The simulations use a dataset based on the European system in 2050, where it is found that SOVN (an earlier version of FanSi) shows a better utilization of the hydropower flexibility and greater reduction of the prices than the EMPS model [19].

The thesis finds that an increase in hydro generation in Norway quite strongly can reduce peak and average power prices in neighboring countries. It is also found that flexibility in demand can smooth out volatile power prices and that just 5% flexibility in demand in times with high power prices can remove all rationing compared to a system without. Combining a system with flexible demand in high price periods and an increase in Norwegian hydro generation from 31 to 41 GW will decrease prices in Germany, the Netherlands, and the UK by around 13%.

The thesis concludes that Norwegian hydropower can contribute to balance variability in future wind- and solar production in neighboring countries. This is if challenges like sufficient national and trans-national capacity and Norwegian public opinions are met. In such a way, Norway can contribute to the EU´s ambitions on a power system with low emission of green-house-gases.

The articles reviewed show that there is conducted some research in this field of study. Many articles have used EMPS as an analysis tool for their research. In the Ph.D., [19], it was found that an earlier version of FanSi gave a better utilization of the hydropower flexibility. In addition, the model is assumed to better handle uncertainties than EMPS [19]. Therefore, in this thesis, FanSi is used as a simulation tool to contribute to understanding the complexity of the North-European power system. As mentioned in section 2.4, integration of variable energy sources increases the vulnerability of the power system. Understanding how external cables and prices, capacities on cables, and variable energy sources affect the power system is crucial for optimal planning and predictions. It can contribute to building a more reliable power system in the future.

3 Theory

Parts of the text in this chapter is from the project thesis written about the same topic in the fall of 2021.

3.1 Social welfare

Social welfare is a term that describes the collected effect on society in a simple manner [72]. The term is used to describe the consequence of an implemented measure and is used both by politicians and governments in decision-making [72]. The term is utilized as one wants to use the resources in an effective way to create the largest amount of welfare in society.

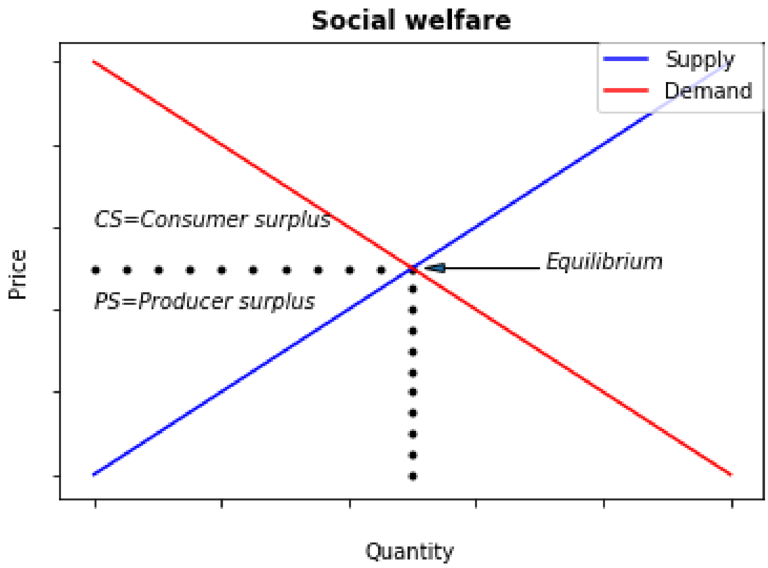

Figure 3: Social welfare

Social welfare is the sum of consumer- and producer surplus. The total surplus (social welfare) is maximized if the cross-section between the demand and supply curve represents the marginal cost [69].

The consumer- and producer surplus is shown in figure 3. The consumer surplus is represented by the upper triangle under the demand curve. It represents the difference between what the consumer pays and what the consumer is willing to pay. If the consumer would be willing to pay 70 NOK, but the market price is 60 NOK, the consumer surplus becomes 10 NOK. The producer surplus is the lower triangle over the supply curve. It represents the difference between the product price of the producer and the price the producer would be willing to sell the product for. If the market price is 100 NOK, but the producer would sell the product for 70 NOK, the producer surplus is 30 NOK. One can also describe it as the earnings from selling the product, minus the cost of production [69].

When calculating social welfare in actual cases, there is often a need for generalization to include all the relevant factors [72]. As a main rule, all economic consequences for all factors must be considered [72]. Usually, one wants to consider all factors, but there is often a need for generalization to ensure that the problem is manageable [72].

3.1.1 Loss in social welfare

From figure 3 the market price is set to the equilibrium, the point where the demand curve and supply curve intersects. What happens if the quantity is set lower than this equilibrium? This can be seen in figure 4. In this setting, the willingness to pay is higher than the production cost. This means the social welfare could have been increased if choosing a higher quantity [72]. The loss in welfare can be seen in figure 4.

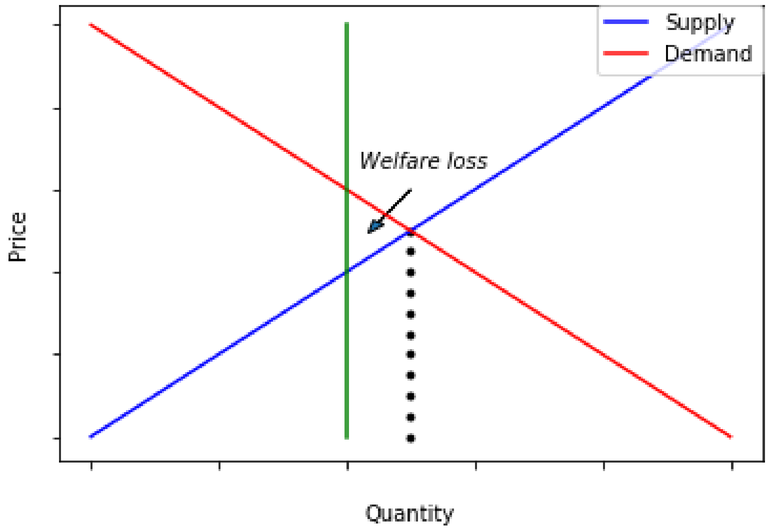

Figure 4: Welfare loss when choosing a quantity lower than in equilibrium

There will also occur a loss in welfare if the quantity produced is higher than the quantity in equilibrium [72]. This is shown in figure 5. The production cost is higher than the willingness to pay, and the social welfare could have been increased if the quantity were decreased. The loss in social welfare can be seen in figure 5.

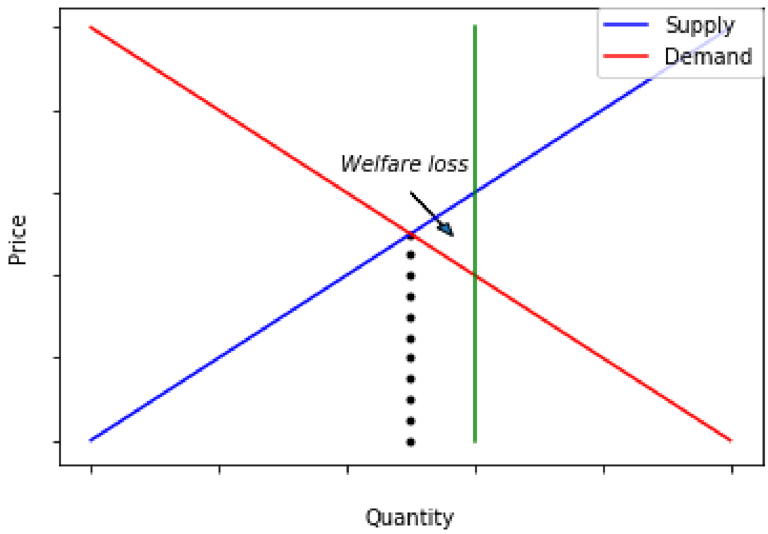

Figure 5: Welfare loss when choosing a quantity higher than in equilibrium

Both in a setting where the quantity is chosen lower or higher than equilibrium, there will occur a loss in social welfare as the setting is not optimal. The First Fundamental Theorem of Welfare Economics states that in a market with free competition, the equilibrium is Pareto efficient [54]. The meaning of Pareto efficient is that no one can get it better without anyone else getting it worse [55]. This gives a theoretical basis for using optimization models to analyze the market [72].

In the Nordic power market, the objective is to maximize social welfare, and long-term gains for all countries [21]. The Nordic power market is deregulated, which means there is free competition, and the price is set based on a balance between supply and demand [46].

3.1.2 The effect of rationing price on social welfare

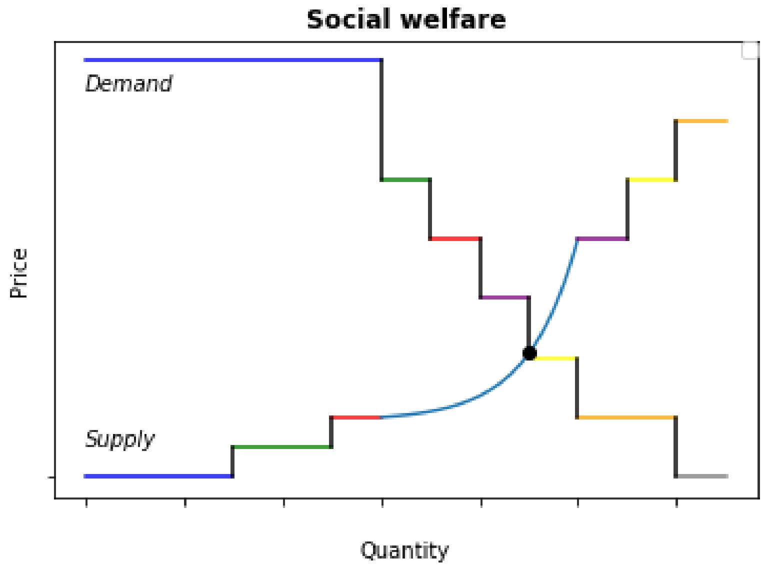

Figure 6: Supply- and demand curve

In figure 6, an example of a supply- and demand curve with supply and demand from different producers and consumers is presented. The first part of the line for the demand curve, the blue part, is the firm demand. This is the part which must be covered. The price here corresponds to the rationing price. On the supply curve, the three first steps represent the cheapest energy sources like solar and wind production, and the fourth step, which is the light blue curve, represents the water values for hydropower production. The last three steps represent more expensive energy sources like oil and gas.

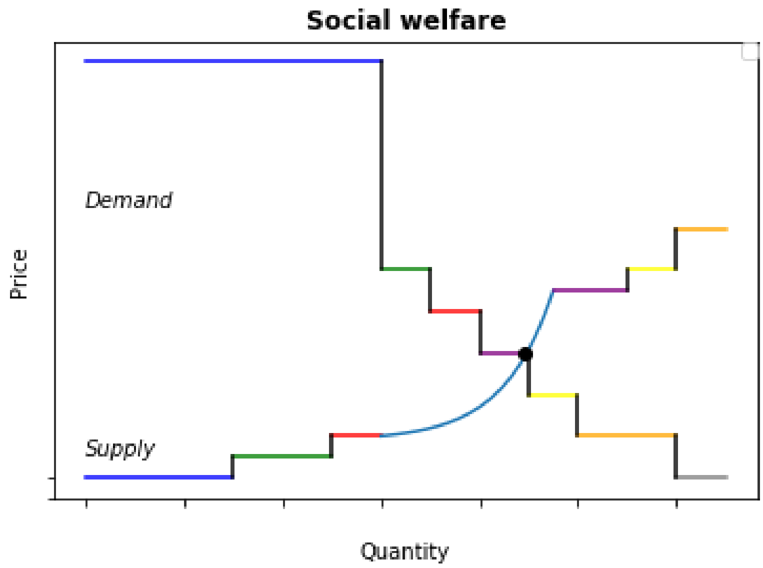

Figure 7: Supply- and demand curve when rationing price is set high

When the rationing price is set higher, the firm demand part of the curve will shift upwards. The rest of the demand- and supply curve will not be affected. The price cross will remain in the same place, so the producer surplus will remain the same while the consumer and total surplus will increase. On the other hand, the water values will be affected by the increase in rationing price. This will lead to an increase in water values and work as an incentive to save water. In figure 7, a situation with a higher rationing price and higher water values is shown. In this case, both the consumer, producer, and total surplus will increase.

3.2 Optimal hydro production

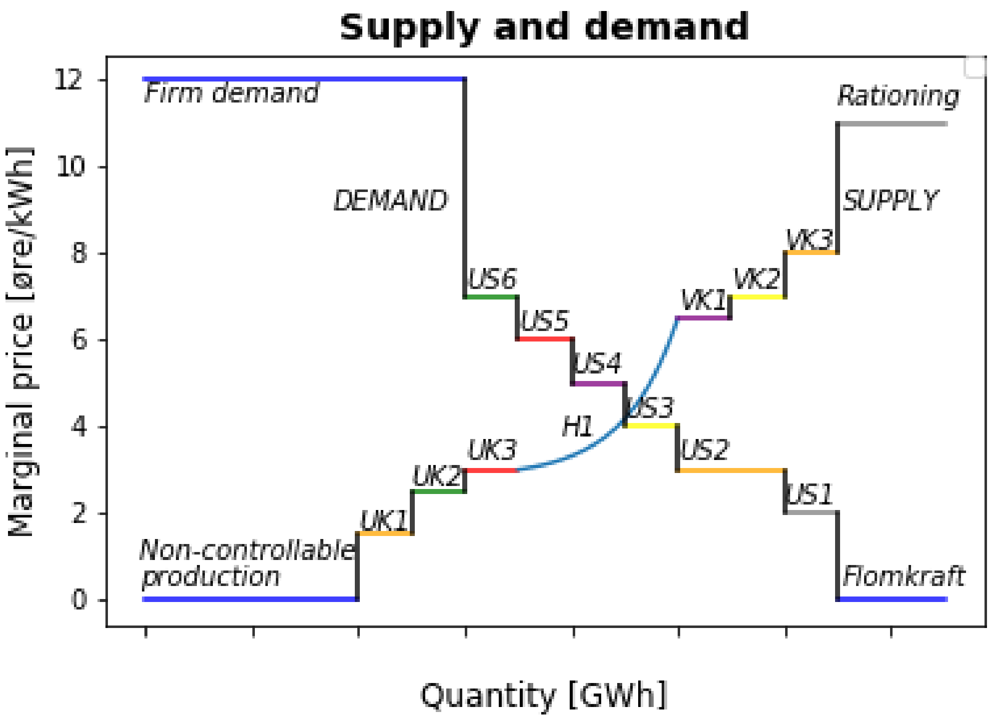

Figure 8: Supply- and demand curve with steps

Figure 8 shows an example of a supply and demand curve, which can represent a given week [69]. The optimal amount of power and the belonging price are found where the demand and supply curves intersect.

The "Firm demand" is price-inelastic and can only be reduced by rationing [69], while "Flomkraft" is the step that covers the power surplus. Setting the price of firm demand higher than the rationing section of the supply curve secures that the firm demand is always met.

UK1, UK2, and UK3 represent the bids from the energy sources with the lowest marginal cost like wind and nuclear, while VK1, VK2, and VK3 represent the bids from energy sources with the highest marginal cost like oil and gas. H1 represents the water value part of the supply curve. US1-US6 represents the contracts for demand.

From figure 8 one can observe that an increase in firm demand will shift the demand curve to the right and give a higher price at equilibrium. This will increase the water values. When implementing energy sources with low marginal cost, like nuclear or wind, the supply curve will shift to the right and reduce the water values and value at equilibrium, as one can use other alternatives with a cheaper price. The same reduction in price can be seen if one introduces more hydropower, based on the same argumentation.

3.3 Scenario reduction

Fast Forward Selection
The following description of the Fast Forward Selection method is mainly based on article [24] and [16].

The fast forward selection method or FFS selects a specified number of scenarios n starting from an empty set. A scenario is here defined as a path starting at the root node and ending in a last stage node. Each scenario is denoted as ω_i, where $i = 1, ..., N$ and each scenario has its corresponding probability p_i. The selection method chooses a subset Ω' of the prescribed size where the distance to the remaining scenarios is the smallest, from the set of all scenarios Ω. $J^{[s]}$ describes the subset which the next scenario can be chosen from after the s-th selection [16].

The Fast Forward Selection algorithm

Step 1: s is set equal to 1. For all scenario pairs, the distances $c^{[1]}_{k,u}$, are calculated as

$$c^{[1]}_{k,u} = c(\omega_k, \omega_u), k, u = 1, ..., N. \tag{1}$$

Following, the weighted distances $z^{[1]}_u$ from each scenario to the other scenarios are calculated as

$$z^{[1]}_u = \sum_{k=1\ k\neq u}^{N} p_k c^{[1]}_{k,u}, u = 1, ..., N \tag{2}$$

The scenario with the smallest weighted distance is chosen as $u_1 = arg\ min_{u\epsilon[1,...,N]} z^{[1]}_u$, and the set is updated $J^{[1]} := J\{1, ..., N\}\backslash\{u_1\}$

Step 2: s is set to s+1. The distance between the scenario pairs is replaced with the smallest distance of the original distance between the pair, or the distance to the scenario that was chosen in s-1. This is mathematically modelled as:

$$c^{[s]}_{k,u} = min\ \{c^{[s-1]}_{k,u}, c^{[s-1]}_{k,u_{s-1}}\}, k, u\ \epsilon\ J^{[s-1]} \tag{3}$$

Consecutively, the weighted distances z_u, are calculated of each scenario on the s-th selection:

$$z^{[s]}_u = \sum_{k\epsilon J^{[s-1]}\backslash\{u\}} p_k c^{[s]}_{k,u},\ u\ \epsilon\ J^{[s-1]} \tag{4}$$

Choose $u_s = arg\ min_{u\epsilon J^{[s-1]}} z^{[s]}_u$ and the set $J^{[s]}$ is updated. $J^{[s]} := J^{[s-1]}\backslash\{u_s\}$

Step 3: If the chosen number of scenarios is less the the specified number n, return to the second step.

Step 4: All the scenarios whom are not selected as a part of the subset will have a probability of 0. The optimal redistribution rule is used to add the probabilities of all the scenarios that were not selected.

$$q_j = p_j + \sum_{k \epsilon J(j)} p_k \; for \; all \; j \; \epsilon \; \Omega', \tag{5}$$

where $L(j) := \{k \, \epsilon \, \Omega \backslash \Omega', j = j(k)\}$, and $j(k) = arg \; min_{j \; \epsilon \; \Omega'} \; c(\omega_k, \omega_j) \; for \; all \; k \, \epsilon \, \Omega \backslash \Omega'$

The result is a subset where each of the scenarios $\omega_i \; \epsilon \Omega'$ has a probability p_ω, which can be different from the original probability p_i before the scenario reduction. The sum of all probabilities p_ω equals 1.

4 FanSi

Parts of the text in this chapter is from the project thesis written about the same topic in the fall of 2021.

4.1 Introduction to FanSi

FanSi is a long-term hydro-thermal scheduling model (earlier named SOVN) developed by SINTEF Energy Research. The project with developing the model (SOVN) started in 2013 and ended in 2017 [26]. The project aimed to create a new fundamental hydro-thermal market model with a detailed representation of the hydropower system and was founded by the Research Council of Norway, Statnett, Statkraft, BKK, and NVE [26].

The model is built on a concept that uses historical records for inflow to represent future uncertainty. It is a model which combines optimization and simulation, referred to as a *scenario fan simulator* (SFS) [26]. The model is based on stochastic linear programming (SLP)[27]. Another widely used and well-tested model for long-term production planning is EMPS. This model is used by many market players in the Nordic power market [18]. The difference between the EMPS model and FanSi is that in FanSi the water reservoirs are not aggregated into one large imaginary reservoir. The water values are calculated directly for each individual reservoir. This leads to a drastic increase in the computational time needed, which is the main drawback of the model and prevents operational application.

One of the principal purposes of FanSi is to handle short-term effects such as transmission grid constraints and ramping, hourly pumping , and variable solar- and wind resources.

4.2 Model description

The objective of the long-term hydro-thermal scheduling problem is to minimize the expected cost of operating the system over the specified scheduling horizon [25]. To describe the solution method the two articles [25] and [26] are used.

4.2.1 Solution method

FanSi uses historical values to model uncertain variables and contains a set S with these values. By solving Scenario Fan Problems along all scenarios $o \epsilon S$, the model optimizes sequences of decisions. A Scenario Fan Problem (SFP) is a two stage stochastic linear programming problem and consists of two stages, where the first stage is a operation stage, and the second stage makes up a set of scenario problems. The objective function for the SFP is decomposed using Benders decomposition giving the following equations:

$$min_{u_o,\alpha_o}\ Z_{o,t}(x_{o,t-1},u_{o,t})+\alpha_{o,t+1} \tag{6}$$

$$min_{u_s}\ \sum_{t_s=t+1}^{\hat{T}} Z_{s,t}(x_{s,t_s-1},u_{s,t_s})+\Phi_{x_s,\hat{T}} \tag{7}$$

$$\alpha_{o,t+1}+\pi_c x_t \geq \beta_c \tag{8}$$

If the planning period is set long enough, the end of the horizon value of stored water, Φ, can be set to 0.

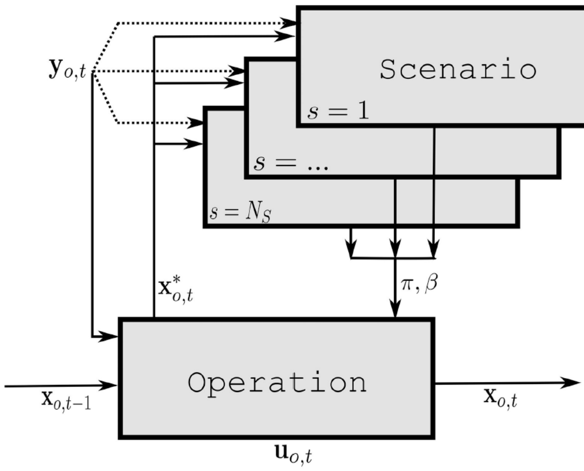

Figure 9: FanSi simulator scheme
Source: [25]

For a certain scenario $o \in S$, and a time stage $t \in i....T$, the vector $x_{o,t-1}$ in figure 9, gives the physical state from the previous solved Scenario Fan Problem for scenario o. $y_{o,t}$ is the realisation of the stochastic variables and is assumed known. This follows the scenario o for week t, but from $t+1$ until the end of the scheduling horizon it can follow any of the other scenarios in the set.

The first operational problem is solved to create a trial state solution $x^*_{o,t}$. The trial state is taken in as the initial state in the scenario problem, and $x_{s,t} = x^*_{o,t}$. The operational decision of the first stage $u_{o,t}$ is stored, and to set the end-value coupling for the first stage Benders cuts are provided. To create the cuts the optimal objective from equation 7 and its sensitivities are used. These cuts have coefficients π, and right hand sides β. The model uses a rolling horizon, where one week is the length of the operational decision period and for the scenarios the length is fixed.

4.2.2 SFS and SFP

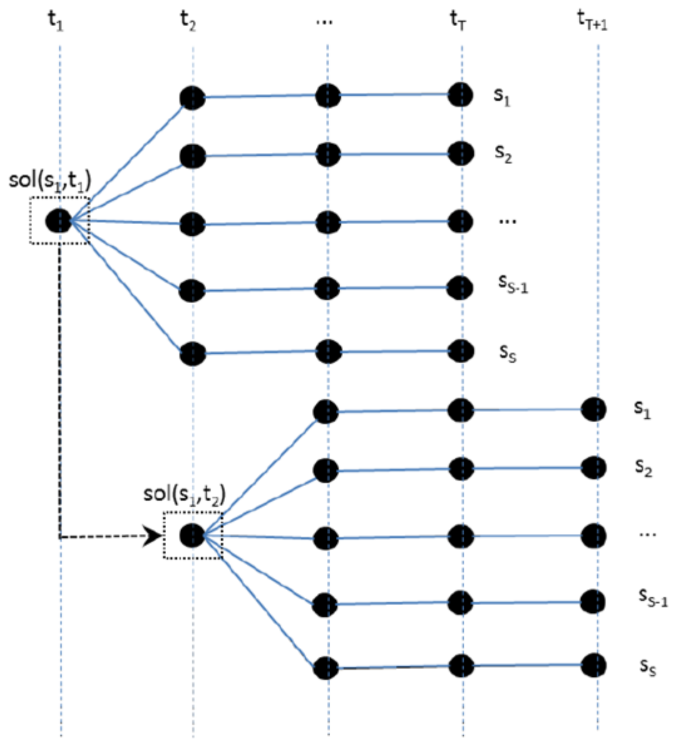

Figure 10: SFS logic illustration with an SFP for each time step t_1 and t_2
Source: [26]

The SFP is a two-stage stochastic linear programming problem. Given a scenario s_1 a SFP is built. This is shown for times t_1 and t_2 in figure 10. T represents the number of weeks the system should be scheduled for. The first stage of the SFP problem is modeled as an operational problem. This equals SFP(s_1, t_1). The second stage is a scenario problem consisting of time steps t_2 to t_T. In the first decision stage, a week is given and the stochastic variables are known. The second-stage covers the rest of the planning period, where the stochastic variables can obtain values from any of the scenarios. Sol(s_1, t_1) in figure 10, represents the solution of SFP(s_1, t_1) and the values for the stochastic variables from this will be passed on to SFP(s_1, t_2). This will be the starting point for the second SFP. This procedure is done such that a first-stage solution is established for all time steps for the given scenario. This is continued for the rest of the scenarios $s_2 - s_S$, where S equals the total number of scenarios in FanSi.

A general formulation of a SFP which is a stochastic linear problem, is shown below:

$$Z = min\ c_1^T x_1 + \sum_{s=1}^{S} p_s c_2^T x_{2,s} \tag{9}$$

$$A_1 x_1 = b_1 \tag{10}$$

$$T x_1 + A_2 x_{2,s} = b_{2,s}\ \forall\ s \in S \tag{11}$$

The objective function calculates the cost of the first-stage decision variables (x_1) in the first term and the cost of the S different second-stage decisions ($x_{2,s}$) in the second term. p_s is the probability of a scenario occurring, and S is the number of scenarios. This formulation operates with three different T's. Subscript t is used to describe the given week, T in combination with x is used as a representative for a coefficient, and T as a superscript is used to describe the transpose.

SFP is illustrated in figure 11 below. The decision in the first-stage is scenario-invariant, the remaining time steps in the second-stage decisions are related to one of the five scenarios. For the SFP, equation 10 holds the set of first-stage constraints, and 11 contains the scenario constraints for the second stage.

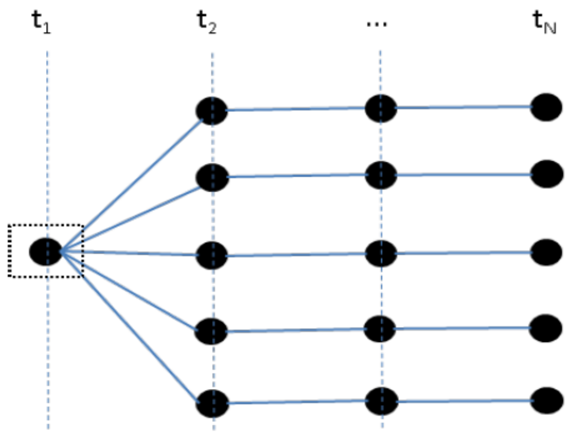

Figure 11: SFP logic illustration
Source: [26]

The goal of solving an SFP is to get a first-stage decision that can be implemented in the simulator. This solution is stored. The decisions from the second stage provide Benders cuts to set the first-stage end-value coupling and are not used in the scenario fan simulator.

4.2.3 Benders decomposition

The SLP problem can be decomposed into a stage-wise decomposition. The first stage decision is created as a first stage problem.

$$Z_{first} = min\ c_1^T x_1 + \alpha \tag{12}$$

$$A_1 x_1 = b_{11} \tag{13}$$

$$\alpha + \pi^T x_1 \geq b_{12} \tag{14}$$

The state variable solution from the first stage problem containing values for the end-reservoir in the first week is passed to the sub-problem. The decision problem along one of the second-stage scenarios represents a sub-problem.

Variables containing reservoir levels are set as parameters to the right-hand-side of the constraints in the second stage.

$$Z_{sub}^s = min\ c_{2,s}^T x_{2,s} \tag{15}$$

$$A_2 x_2 = b_2 - x_1 \leftarrow \pi_s \tag{16}$$

The solution of the sub-problem give simplex multipliers π_s on the reservoir balances for the first load period in the second-stage. After all the second-stage sub-problems are solved, average multipliers π and right-hand side b_{12} are used to construct a cut for the first-stage problem:

$$\pi = \sum_{s=1}^{S} p_s \pi_s \tag{17}$$

$$b_{12} = \sum_{s=1}^{S} p_s (Z_{sub}^s + \pi_s^T x_1) \tag{18}$$

The value of the objective function of the first-stage problem will form a lower boundary, and cuts containing the future-cost function will gradually increase the lower boundary.

$$Z_{low} = Z_{first} \tag{19}$$

The upper boundary is modelled as:

$$Z_{up} = c_1^T x_1 + \sum_{s=1}^{S} p_s c_{2,s}^T x_{2,s} \tag{20}$$

$$Z_{up}^i = min(z_{up}^{i-1}, z_{up}^i) \tag{21}$$

When the difference between the boundaries are within a defined tolerance, convergence is reached.

$$Z_{up} - Z_{low} \leq \varepsilon \tag{22}$$

4.3 Scenario reduction

FanSi is modelled using historical data for inflow to predict possible future scenarios as inflow varies dependent on the weather. In the second-stage of the SFP, each scenario has the same probability in the beginning. If the model contains 50 inflow scenarios, each with 3 price scenarios, the SFP would have a total of 150 scenarios to evaluate. The user can specify the number of scenarios that should be used in the SFP. The scenario reduction is used to reduce computational time and for FanSi price scenarios does not make up a part of the evaluation criterion. The scenario reduction method used in FanSi is based on a Fast Forward selection method, which is described in 3.3 [26].

The reduction uses a scenario value to detect similar scenarios such that one type of weather year is represented through a specific scenario or scenarios. This depends on the number of scenarios specified by the user. The scenario value E_i in 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 [26]. The energy equivalent to sea kWh/m^3 is utilized for each inflow series in the conversion to GWh/time step.

The following steps are done in the reduction algorithm. The algorithm first calculates the probability-weighted distances ($p_i * D_{ij}$) to all the other scenarios given an initial scenario. The distance D_{ij} is the total difference in scenario values for all units and time steps given in equation 23. p_i is the probability of scenario i.

$$D_{ij} = \sum_{t \in T} \sum_{n \in N} (E_{nit} - E_{njt})^2 \tag{23}$$

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 scenario with the lowest distance is removed and the probability is updated for the scenario: $p_j = p_j + p_i$, assuming that scenario i is removed. This is continued until the specified number of scenarios is obtained. The whole scenario generation process consists of four steps. First, the inflows are given by the observed values. Then the inflows are corrected for snow storage information. A reduction is then done on the snow-corrected inflows and in the end, a smoothing of the scenarios is done to fit the known inflow of the first-stage week. The smoothing is done to avoid abnormal jumps in inflow data. In this way, the scenarios are adjusted to fit the first-stage data of the chosen weather year. The way that the scenario reduction is performed is not thoroughly investigated. It might therefore exist other methods which would give a better representation of different inflows. The validity of the number of scenarios chosen in FanSi is discussed later on in this thesis.

4.4 Control input file

FanSi is run through a control input file. The file contains parameters describing how the optimization and simulation should be done and information about variables that the model needs. The number of weeks in the simulation, max number of Bender iterations and if an expected scenario should be used are examples of information in the control input file. The default will be used if the parameters are not specified beforehand. An example of a control file is given in Appendix A, 13.1. Some parameters in the control input file are described below.

The information in this part is based on the SOVN user manual found in [70].

MAXITER sets the maximum allowed iterations for each Benders decomposition problem, which can be set to any positive integer.

MAXDIFF gives the convergence criteria for Benders iterations by comparing the difference between maximum upper and lower boundary. The upper boundary is found as the average of the first weeks solution costs plus scenario costs, while the lower bound is found as the objective function when solving the master problem.

NSCEN equals the number of scenarios in the scenario fan. If the value given for this parameter is 1, a deterministic scenario fan is used. If the number specified is less than the scenarios available in the model, a scenario reduction algorithm will be conducted.

NWEEKSCEN describes the number of weeks used in the scenario fan. If given zero the water values from EMPS are directly used in the market clearing problem.

LSEKV specifies if the simulation should have a sequential (T) or accumulated (F) time resolution and the time resolution of the master problem is set. Using a sequential time resolution increases the computational time.

LASTWEEKACC defines the last week in the problem which is simulated using accumulated time resolution.

LASTWEEKSEQ defines the last week simulated using sequential time resolution. Remaining weeks will be simulated using a weekly time resolution. If LASTWEEKACC is set to 3, the three first weeks will be treated with the same time resolution as the master problem, which have 56 load periods of 3 hours.

4.5 Serial vs Parallel

4.5.1 Serial vs parallel simulation

When using FanSi, it can either be run through serial- or parallel simulation. When there is no knowledge about the systems current state, one can run the model in serial mode. Then, the decisions are arranged in sequence corresponding to the records of historical inflow [27]. For serial simulation, the end reservoir level will give the start reservoir level for the next year. For parallel simulation, the reservoir levels are set to a predefined start level for all weather years.[70]. Serial simulation is often used for expansion planning and studies of the system which is not dependent on the current state. When it is important to have knowledge about the current state of the system, parallel simulation is preferable [27]. Parallel simulations are often used for operational decisions [70].

4.5.2 Serial vs parallel processing

Two processing types can be utilized when running FanSi, respectively serial- or parallel processing. The processes use message passing interface (MPI). For serial processing, one process is run on one computer core, while parallel processing involves multiple processes on multiple computer cores.

Parallel processing in FanSi consists of two levels. The first level includes N groups, where a specific scenario is handled by each group. An administrator conveys which groups handle which tasks. A group have M processes which can either be equal to 1 or NSCEN + 1. The parallelization is most efficient when each group are given NSCEN + 1 processes. Parallelization of the scenario fan make up the second level. The master of a group solves the master week problem and a group of slaves is controlled to solve the fan in parallel [70].

The cases in this thesis are run using serial simulation and parallel processing.

4.6 End-value setting

When using long term hydropower scheduling models like FanSi, long time horizons are preferred as they limit the impact of end value settings. The end values have a greater impact on the larger reservoirs than the smaller ones, which will be discussed more in part 8. Due to computational time there is not always possible to use a adequate time horizon. The end valuation uses water values for aggregated reservoirs from the EMPS model.

The end values are calculated as following: For each reservoir the reservoir volume is discretized into 2% intervals, and each segment is assigned a value given the equation below:

$$c_i = wv_i * E * R \tag{24}$$

wv_i is the water value for the aggregate reservoir in øre/kWh
E is the energy equivalent to sea in kWh/m3
R is the interest rate

In addition, there is also implemented parts of the reservoir drawdown model from EMPS in FanSi. To differentiate between reservoirs when it comes to discharge flexibility and overflow risk, information about the target reservoirs are added [26].

For larger changes in the dataset, water values should be recalculated. New water value calculations can be facilitated by the programs saminn/stfil. New water values are added as files with name "VVERD-<areaname>.SAMK. The water values in the formula above are changed and as a result new end values are calculated to better suit the dataset.

4.7 List of steps

The file "trinnliste.txt" gives an overview of the price dependent power categories of each area. It includes loads and parts of production (excluded hydro production) with an exogenous defined marginal cost [62]. An example of the file is given in Appendix B, 13.2.

An overview of the price dependent power categories is given below:

Kategorinr	Trinnnr	Navn
1	Valgt av bruker	Tilfeldigkraft kjøp og import
2	Valgt av bruker	Tilfeldigkraft salg og eksport
3	Valgt av bruker	Varmekraft
4	Valgt av bruker	Gjenkjøp
5	600 => (Automatisk generert)	Kontrakter med delvis betalingsplikt (Brukes ikke for Samkjøringsmodellen)
6	Valgt av bruker	Kjøp spotmarked (prisrekke)
7	Valgt av bruker	Salg spotmarked (prisrekke)
8	Valgt av bruker	Kjøp refert lastprofil
9	Valgt av bruker	Salg refert lastprofil
20	998	Flomkraft
30	400 => (Automatisk generert)	Prisavhengighet for kontraktsforpliktelser (Last)
40	999	Rasjonering

Figure 12: Table of power dependent power categories
Source: [62]

"Flomkraft" is the step that covers the power surplus. The overall power balance has the following variables: production = load - rationing + spillage power. The variable spillage power is used as a negligible cost in cases where production is higher than the load, and cannot be regulated in other ways. The variable called rationing can be used for a high cost if production is too low.

4.8 Social welfare

In this thesis the program Samoverskudd is run to obtain the social welfare. By running this program one can get the numbers for both demand, production, net loss, the exchange for each area and the different components for social welfare [72]. When running Samoverskudd one must make some decisions, for example which results should be presented and what time resolution should be used [72].

The social welfare is calculated as the sum of four different parameters, the consumer surplus, the producer surplus, the surplus of the transmission system operator and the operational cost [72]. Appendix C, 13.3, show an example of the output from Samoverskudd.

5 Dataset and technical specifications

The dataset named "Sumeffekt_2030_V14_Unik_Ref" from 2019, analyzed in this thesis, is provided from SINTEF Energy Research and an analysis of a similar system can be found in [58]. The dataset is based on lowering GHG-emissions. Therefore, the information reflects ambitions and recent targets for the Northern European power system in regards of 2030. To match the ambitions, the dataset have larger shares of power production from solar- and wind resources. In particular Germany has increased its renewable power production and reduced its coal-based capacity. In addition, the usage of lignite for power production is phased out [58]. Transmission capacities have been increased from Norway to Germany and Great Britain.

5.1 Description of the dataset

5.1.1 System overview

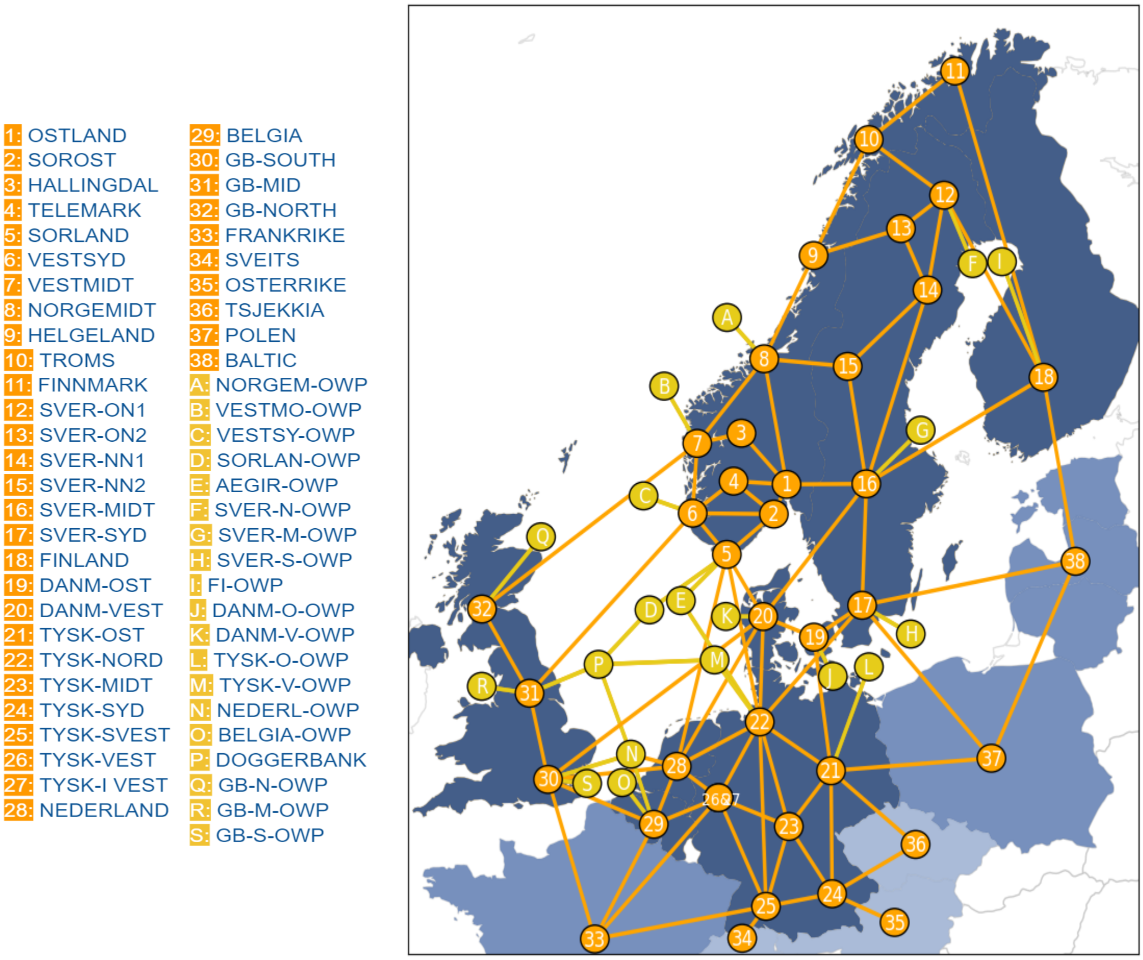

Figure 13: Overview of the areas in the system.

Figure 13 shows all the areas in the system. The yellow points equal areas with offshore wind production. The dataset contains detailed modeling of Norway, Sweden, Denmark, Finland, Belgium, the Netherlands, Germany, France, Poland, the Baltic region and Great Britain in terms of demand and supply of electricity [58]. The dataset is used on a project basis. Therefore, the dataset is not regularly altered to fit all the recent changes in North-Europe. The system contains 57 areas, where 19 areas consist of offshore wind production. Norway has in total 11 bidding zones, Sweden has 5, Denmark has 2, Germany has 7, Great Britain has 2, while Finland, the Netherlands, Belgium, France, Switzerland, Austria, Czech Republic, Poland and the Baltic each have one. A file describing the connections between areas is shown in Appendix D, 13.4. The lines have a power loss varying from 2-5%. Most lines within countries have a power loss of 2%, while connections between countries have higher values ranging up to maximum 5%. There is also a fixed maximum fraction of power flow set to 90% on the subsea cables. To account for the uncertainty in weather, 30 weather scenarios are investigated. These weather years are from 1981 to 2010.

The following details of the areas and system are for the base case. If some aspects of the dataset is changed, it will be specified in the case descriptions in section 6 and 9. More details about the dataset is given in Appendix E, 13.5.

5.1.2 Firm demand

To understand the energy demand situation in Northern Europe, a map of the average yearly area firm demands in TWh, are presented in 14. The color of the areas represents the magnitude of the firm demand with a scale from light green to blue. Therefore, France is the area with the highest firm demand.

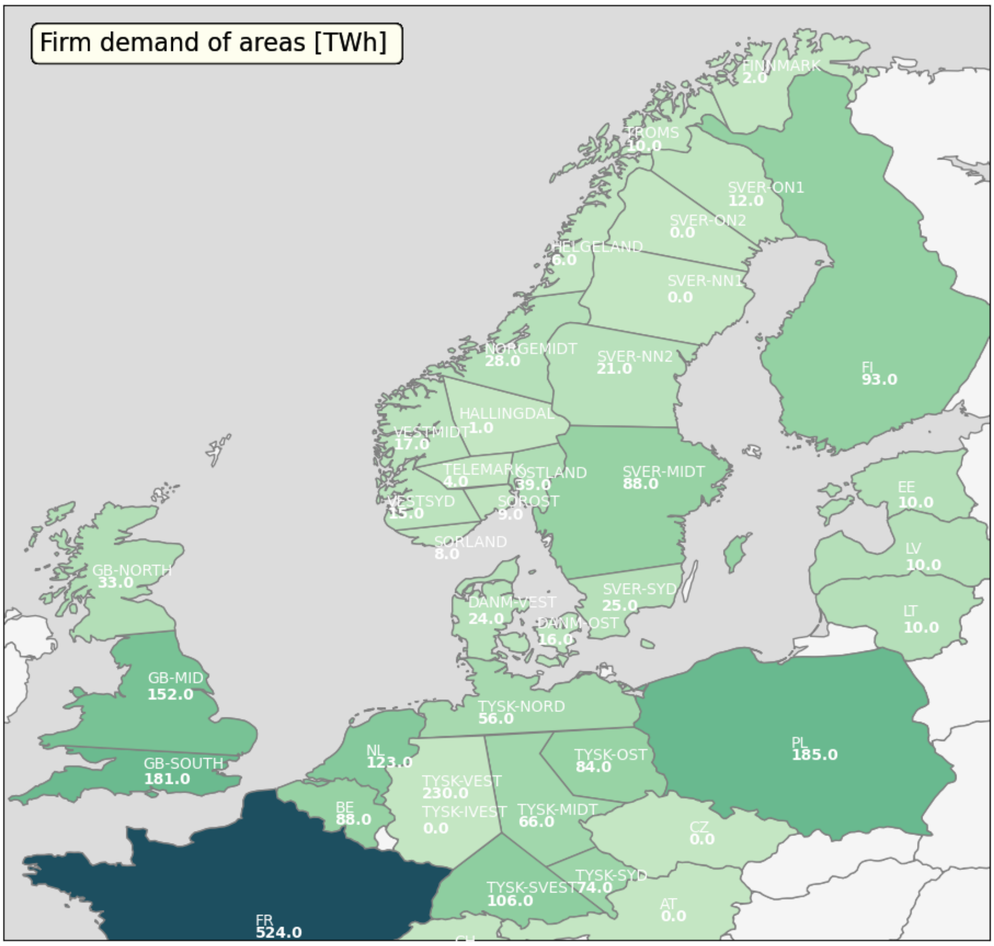

Figure 14: Mean yearly firm demand for areas in TWh

5.1.3 Cables

In figure 15, all the external cables for Northern Europe are shown, respectively with their capacities in MW.

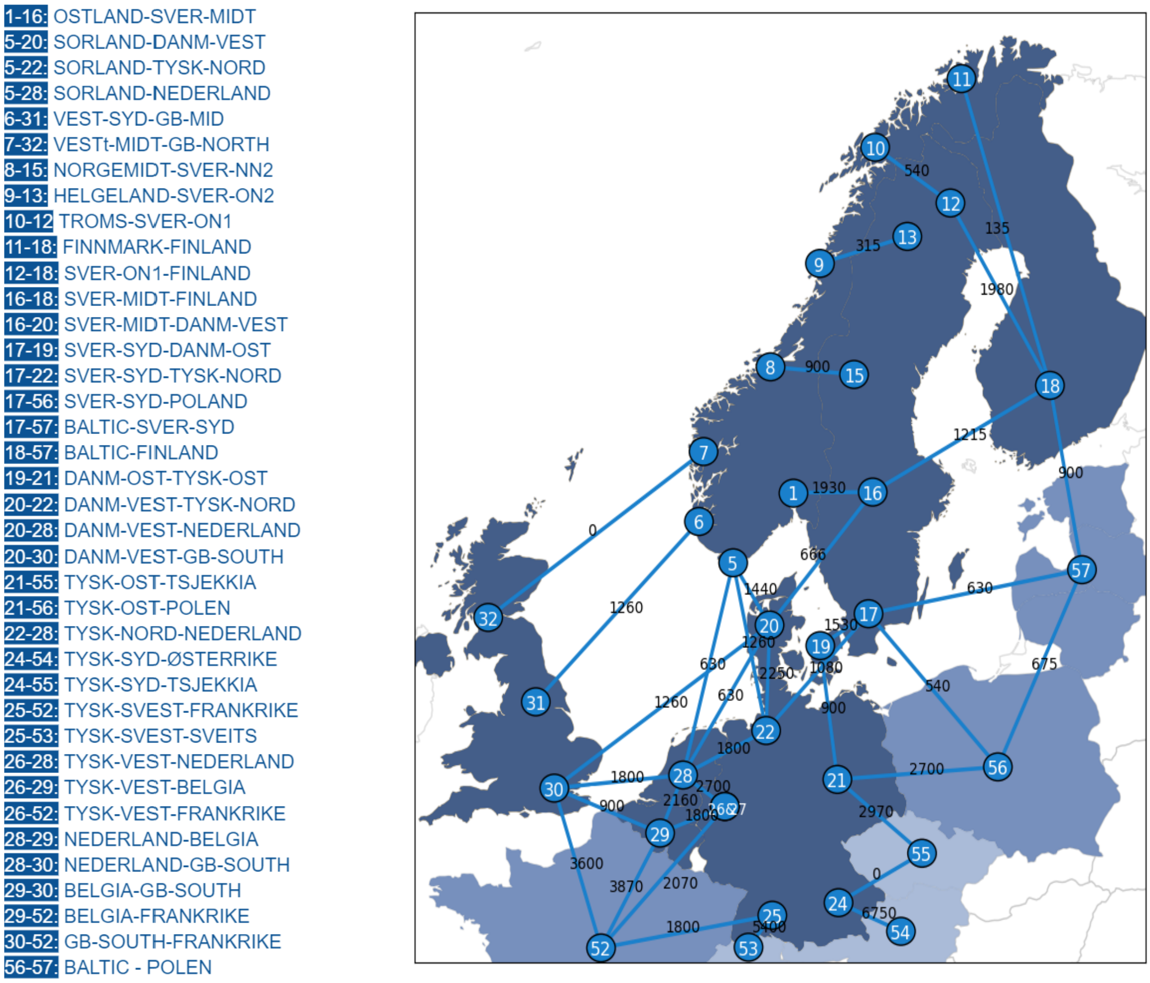

Figure 15: Overview of the external cables of the system with their corresponding capacity in MW

5.1.4 External areas

Switzerland, Czech Republic and Austria are for this dataset modelled with time series of power balances, alternating between positive and negative values. This balance must be covered, which means the system must cover the demand or receive production from these countries in accordance with the time series. For the analysis done it is assumed that this does not affect the system greatly.

5.1.5 State of the system

In order to understand the energy balance of the system, the average yearly renewable production surplus or deficit for each area is presented in 16. Renewable production consists of mean weekly inflow and mean weekly wind- and solar production. This represents the potential renewable production. For countries like Germany, Finland, Great Britain, Belgium, France, Poland, and the Baltic's, renewable electricity production is not enough to cover the firm demand, and other resources have to be used to fulfill the power demand.

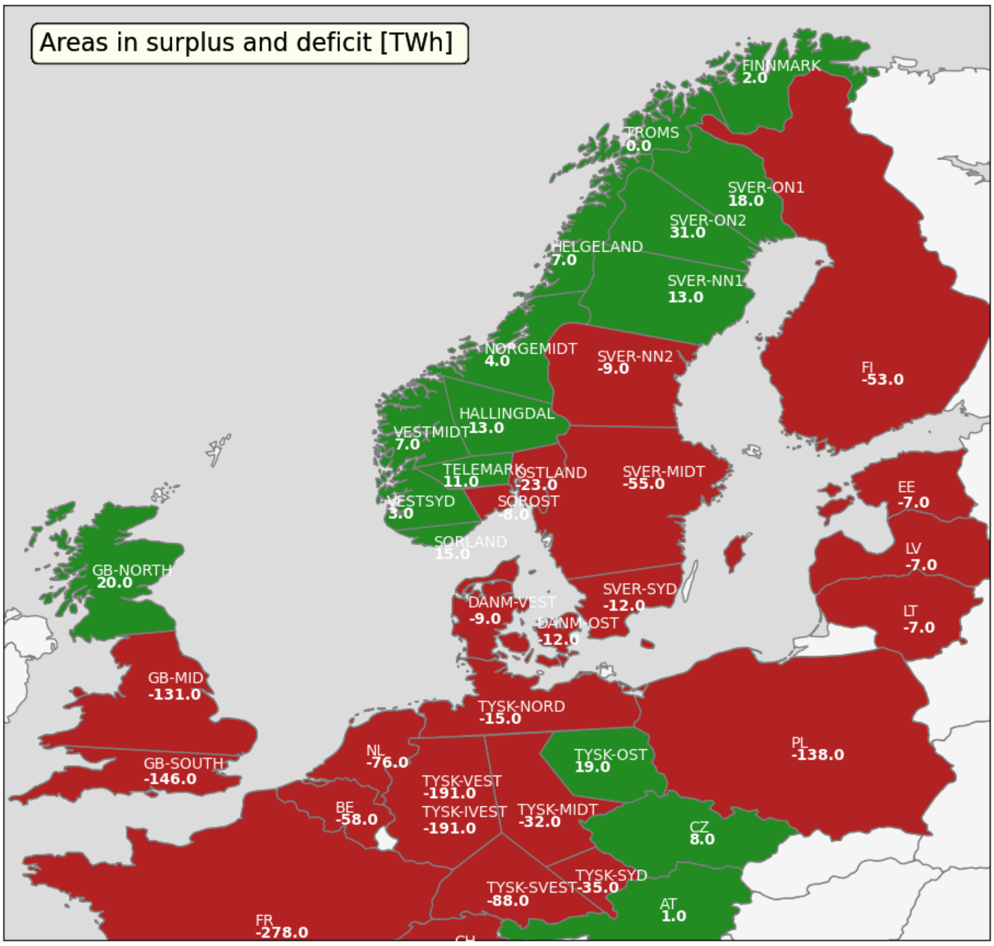

Figure 16: Average yearly production surplus or deficit in TWh for the system

5.2 Market modelling

5.2.1 Contracts

In FanSi, demand is modeled through two types of contracts: fixed- and price dependent contracts [62].

Fixed contracts

The fixed contracts consist of two types: contracts with a predetermined volume and discharge profile, and time of use contracts. The contracts with predetermined volume have a weekly determined demand, which is usually based on earlier known numbers. These types of contracts can for example be industrial contracts [61]. Time of use contracts is defined through maximum power and order within each contract period [62]. The buyers do have some degree of freedom to take out the contract [61].

Price-dependent contracts

The price-dependent contracts make up contracts where the demand can be coupled in and out dependent on a certain pre-decided price. The contracts have information about the capacity in different periods, prices, and power profiles. These types of contracts include the purchase of thermal power, import, export, buyback, and rationing. Power without market, or "Kraft uten marked", is also an example of a price-dependent contract. Whether a contract is coupled in or coupled out is dependent on the power price/water value [62].

Together, the contracts make up a supply- and demand curve which is generated as explained in part 3.2. The curves give a price cross which decides which price-dependent power categories get chosen for each area.

5.2.2 Day-ahead market

The Northern European power market primarily consists of the day-ahead market. The market is based on contracts from suppliers with an hourly delivery description of power for the next day. Through bids and offers the hourly power prices are set for the next day [12]. In FanSi, the representation of the pricing in the power market is replicated by a set price in time sequences. The system contains 56 load periods. The price remains the same for the given hours. The datafile used as input is attached in Appendix F in part 13.6.

Table 1: Day ahead market pricing

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

6 Cases - Scenarios and Parametrization

The case matrix, which gives an overview of the different cases and scenarios run in this thesis, can be found at the bottom of this section in part 6.5. Each scenario represents a change to the default dataset. In the case matrix, the letters specify the scenario, while the number signifies a change in the parameter. While different letters refer to scenarios with different information, numbers only indicate changes to the parameters in the input file. The changes done to the parameters are similar for all the scenarios, meaning A-1, B-1, C-UV-1 etc, have the same input parameters. The same procedure is for cases A-2, B-2... and A-3, B-3... and so on. Therefore, all the different parametrizations will be explained for dataset A, while only the base cases B-1, C-1, D-1, etc, will be explained for the rest of the scenarios. For the default dataset, there is run an extra parametrization. When doing changes to a dataset, it is recommended to recalculate the end water value to suit the changes made. The end water values will be updated for all scenarios except for C-UV.

6.1 Dataset A: Base

A is the letter given to the default dataset. A-1 makes up the base case with the default settings. The other cases ranging from A-2 to A-5 have a different value to one input parameter compared to the default case A-1, while in A-6, the input of two parameters is changed. This is done to see how changing different parameters affect the results, especially social welfare and prices. The importance of different parameters is analyzed. In addition, one investigates how to optimize run time without forsaking the results.

A-1
The default parameters chosen in the base case are decided in discussions with SINTEF based on their know-how about the current version of the FanSi model and can be seen in table 2.

Table 2: Parameters for the base case, A-1

Parameters	**Value**
MAXITER	10
MAXDIFF	10^{-4}
NSCEN	4
NWEEKSCEN	52
LSEKV	F
LASTWEEKACC	1
LASTWEEKSEQ	0

The parameters changed in the following cases are either NSCEN or NSCENWEEK, with an exception of one case. NSCEN and NSCENWEEK represent the number of scenarios and the number of weeks in the scenario fan.

A-2 and A-3
In these two cases, the scenario parameter NSCEN is changed. For A-2, NSCEN equals 10, and for A-3, NSCEN is 20.

A-4 and A-5
In cases A-4 and A-5, the parameter NWEEKSCEN is changed relative to the base case with default settings. It is increased to 104 and 156 respectively for the two cases.

A-6
In this case, which will only be run for dataset A, both NSCEN and NWEEKSCEN are changed. NSCEN is set to 20 and NWEEKSCEN to 104, to investigate how changing both parameters affects the results.

6.2 Scenario B: High fuel prices

In recent years, high fuel prices have affected the European market. In 2021 the gas prices reached higher levels compared to the previous years, which led to higher power prices in Europe. This scenario is an attempt to replicate the current situation, where the chosen gas price reflects the prices seen in 2021 and 2022. The default gas price in the model which is used in dataset A is 19 EUR/MWh. The selected gas price for this dataset is 89,82 EUR/MWh. This value is calculated as the approximate mean gas price between the 1st of October 2021 and the 18th of February in 2022, where the values are gathered from [67]. In FanSi, fuel prices are given in an input file, which can be found in Appendix G, 13.7. The file contains prices for Bio, Lignite, Coal, and Oil together with Gas. To match the change done for the gas price, the prices of the other commodities are scaled up with the same factor as the gas price.

The fuel prices are converted to marginal costs to be evaluated when setting the prices for the areas. The prices given in the input file are used for this calculation. For gas, the energy coefficient is 1,00 MWh/MWh, the emission equals 0,2 tCO_2/MWh, the price is 89,82 EUR/MWh, and a carbon tax of 30 EUR/t is used. For a gas power plant with an efficiency of 59%, the marginal cost is calculated as the following:

$$MC = \frac{82{,}89\frac{EUR}{MWh} + 30\frac{EUR}{t} \cdot 0{,}20\frac{t}{MWh}}{0{,}59} = 150,66\frac{EUR}{MWh}$$

6.3 Scenario C: Removing all the subsea cables connected to Norway

As described in part 1.1, Norway is a part of the European power market with transmission capacity to Sweden and Finland and subsea cables to Denmark, Great Britain, Germany, and the Netherlands. The subsea cables have been widely discussed, especially the last year when the prices have skyrocketed, partly due to these connections. In this scenario, the subsea cables from Norway to Great Britain, Germany, the Netherlands, and Denmark are given a capacity of zero, while the transmission capacity is kept to both Sweden and Finland. This is done to analyze the contribution of the subsea cables to the power market.

C-UV and C-MV
For scenario C, two different datasets are run. In the first version, called C-UV, the end water values are not updated after all the capacities on the subsea cables are set to zero. For C-MV, the end water values are updated based on the new capacities. This is done to see how the end valuation affects the simulation results.

6.4 Scenario D: Scaling up the capacity to Great Britain

The subsea cable NorthConnect from Eidfjord to Scotland is planned to be in operation by 2024 [52]. This connection has been politically controversial. Many fear that the connection will increase the area prices in Norway due to the high prices in Great Britain [41]. NVE estimated a price increase of around 1-3 øre per kWh during the cables lifetime [50]. Price area NO5, the location of Eidfjord, has a high production surplus. Building this connection between Norway and Scotland will utilize more of the potential production [41]. In NVE's assessment, the cable is expected to give social welfare of about 8,5 million kr over its estimated lifetime of 40 years [50].

In this scenario, it is investigated how increasing the capacity on the subsea cables North Sea Link and NorthConnect between Norway and Great Britain affects social welfare, area prices, and transmission. These cables represent cables 6-31: VEST-SYD-GB-MID (North Sea Link) and 7-32: VEST-MIDT-GB-NORTH (NorthConnect), which can be seen in figure 15. NorthConnect is in dataset A given a capacity of zero but in this scenario given a capacity of 1260 MW. On the other side, North Sea Link is in dataset A given a capacity of 1260 MW, and in this scenario, it is set to 2520 MW. Running this scenario, one can observe the effects of increased capacity to Great Britain.

6.5 Case Matrix for Scenarios and Parametrizations

Table 3: Case Matrix for Scenarios and Parametrizations

Change in parametrization/ Change to system	**Default**	**+Increased scenarios**		**+Increased scenario length**		**+Increase in both scenarios and scenarios length**
NWEEK:	52	52	52	104	156	104
NSCEN:	4	10	20	4	4	20
Dataset: A	A-1	A-2	A-3	A-4	A-5	A-6
Scenario: B	B-1	B-2	B-3	B-4	B-5	
Scenario: C-UV	C-UV-1	C-UV-2	C-UV-3	C-UV-4	C-UV-5	
Scenario: C-MV	C-MV-1	C-MV-2	C-MV-3	C-MV-4	C-MV-5	
Scenario: D	D-1	D-2	D-3	D-4	D-5	

7 Comparing the effect of the different scenarios

This part of the master's thesis addresses how changes to the original dataset affect the simulated operation of the system. Questions that are further investigated are how does an increase in fuel prices impact social welfare, area prices, and reservoir levels, what is the significance of subsea connections to Norway, and how does an increase in capacity to Great Britain influence Northern Europe. The main point is to analyze how changes in the dataset are reflected in the results.

The results from the -1 parametrizations are used to investigate the differences between the scenarios. All the different parametrizations give quite similar differences between the different scenarios. Therefore, -1 the base parametrization, is chosen. The dataset divides Norway into 11 price areas. A selection of these areas is chosen to present the results. The analysis utilizes the areas Sorland, Sorost, Vestmidt, Norgemidt, and Finnmark. Together they give a variety of areas with different properties. Sorland is connected to the North-European system through subsea cables, Sorost represents an area with high demand, Vestmidt has a significant amount of hydro production, while Norgemidt and Finnmark represent areas with different geographical locations and a result is often lower area prices here compared to those in the south. As the tendency of the results is similar for all areas, often one area is presented. In addition, some results are presented for GB-North and Tysk-Nord. These two areas are selected to represent the rest of the system as they will give a good indication of how the scenarios affect other areas than Norway.

7.1 Social welfare

The average social welfare, consumer- and producer surplus for all weather years for both the whole system and Norway, for the scenarios A-1 to D-1, are presented in table 4. The + and - numbers equal the difference between the given number and the base dataset, A-1.

Table 4: Average producer- and consumer surplus and social welfare for the system and Norway

Area	**Social welfare [Mkr]**			
	A-1	**B-1**	**C-MV-1**	**D-1**
Producer surplus	505937,58	1538733,01 +**1032795,43**	530810,73 +**24872**	494920,82 **-11016,76**
Consumer surplus	64052236,91	62506907,05 **-1545329,86**	64017018,24 **-35218,67**	64065979,06 +**13742,15**
Total social welfare	64617533,45	64240646,29 **-376887,16**	64609980,60 **-7552,85**	64620542,58 +**3009,13**
Norwegian producer surplus	40018,36	115178,54 +**75160,18**	29402,26 **-10616,1**	40966,56 +**948,2**
Norwegian consumer surplus	2579008,05	2512064,37 **-66943,68**	2588536,92 +**9528,87**	2578499,6 **-508,45**
Total Norwegian social welfare	2622288,58	2638695,89 +**16407,31**	2617939,18 **-4349,4**	2623766,51 +**1477,93**

One can observe from the results that higher fuel prices (Scenario B) significantly reduce social welfare compared to the base scenario. An increase in fuel prices lifts the area prices to a higher level, seen in figure 18 and table 5. The producers benefit significantly from the price increase, while consumers pay a high cost. The total social welfare of Norway has increased due to the high incomes of producers as a cause of the cheap resources in Norway. This correlates to the tendencies in Norway over the past year.

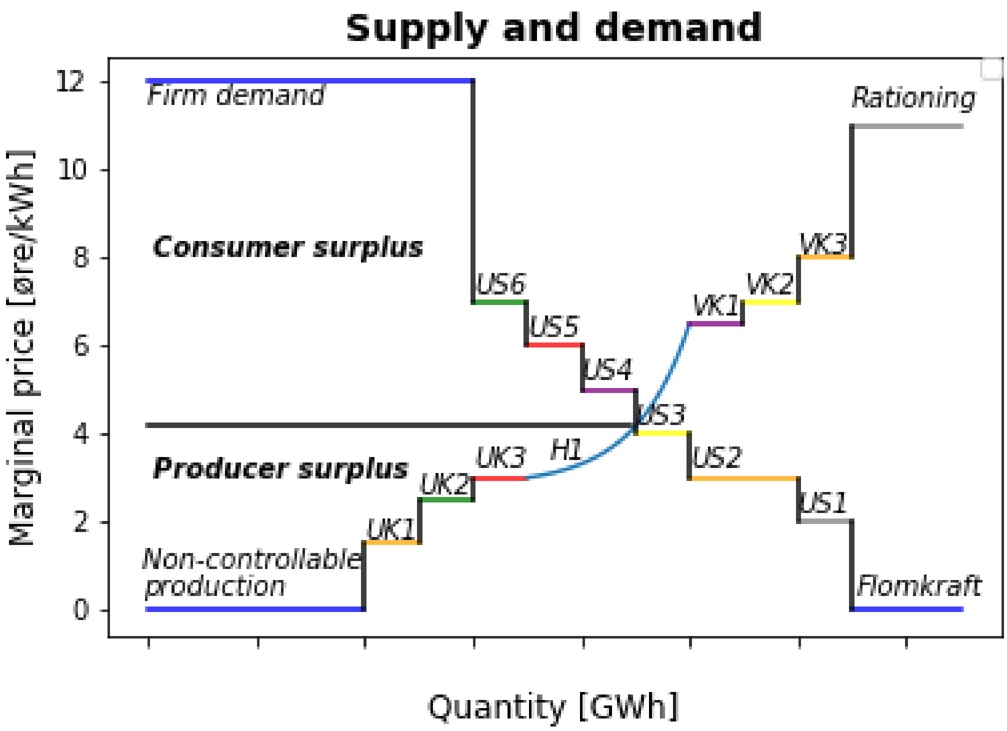

Figure 17: Supply- and demand curve with consumer- and producer surplus

An increase in fuel prices will affect the water value as the value of water will augment. In the supply and demand curve, it will lead the curve for H1 in figure 17 to intersect the demand curve at a higher level. In addition, it leads to an increase in the price levels for the gas and oil steps, which will give a lower consumer surplus and a higher producer surplus. The quantity produced and covered will be less, and as a result, there is a loss in social welfare.

One can observe a decrease in social welfare when removing the subsea cables connected to Norway, scenario C. On the other hand, the reduction in social welfare is significantly smaller than in scenario B. Cables contribute to a price equalization between the connected areas. When cables are disconnected, it will lead to more considerable area differences, leading to a lower social welfare. The Norwegian social welfare experiences this reduction. Removing the subsea cables leads to no trade between countries, and producers lose income as exports diminish, which is the situation in Norway for scenario C. On the other hand, area prices will be low, giving consumers a profit. For other countries, prices are higher as a cause of using more expensive resources to cover their demand. The producers receive a surplus, while consumers get the disadvantage of higher area prices.

When increasing the capacity from Norway to Great Britain, one can see the opposite. Establishing a new connection between areas will always give the same or better social welfare. If the introduced line relieves bottlenecks, the social welfare will be higher as a cause of better facilitation for resource utilization in the system. There will be a price equalization between the areas connected, leading to greater social welfare.

The increased possibility of export leads to a higher producer surplus in Norway. From figure 23, both GB-Mid and GB-South are deficit areas, meaning they cannot cover their firm demand with their area production. Increasing the capacity to GB-North and GB-Mid will lead to export directly to the areas in need and relieve the system of bottlenecks. The result of direct flow to a deficit area is less power loss. Therefore, there is a better utilization of electricity. The Norwegian consumers experience a decrease in the surplus. As Norwegian area prices increase slightly due to the new connection to Great Britain, seen in 19, consumers pay a higher price. Norwegian producers benefit from the line, as the cable signifies an export possibility for Norway. Even though area prices increase due to the connection, Norwegian area prices are still lower than European prices. This price difference gives income to the Norwegian power producers.

From this, as one expected, increased fuel prices give higher area prices. The higher prices show the importance of replacing thermal assets with renewable sources to diminish their impact. Thus, creating a system with cheap resources. When fuel prices increase, producers benefit while consumers pay a higher area price. For Norway in surplus, removing the subsea cables leads to minor income for the Norwegian producers as there are less export possibilities. The Norwegian consumers benefit as area prices are lower. For the total system, producers benefit and consumers lose. With an increased connection to Great Britain, social welfare increases. Norwegian producers receive a higher income as a cause of the added amount of export. Nonetheless, the Norwegian consumers experience a slight price increase leading to a loss in consumer surplus. The cables to Great Britain are an important component contributing to the European power market, displacing electricity directly to the deficit areas and relieving bottlenecks. The increase in social welfare in D supports this statement.

7.2 Area prices

Figures 18 and 19 present duration curves with values for all weather years for the different scenarios and A and D. In figure 20, the average hourly area prices for an average, a dry, and a wet year are presented with their seasonal differences. 1996 represents a dry year since it is the year with the lowest inflow in the dataset. On the other hand, the year 2000 reflects a wet year. The seasonal differences consist of summer and winter variations. Summer equals the months June, July, and August, while winter is equivalent to December, and January, and February for the following year. These results are combined in a bar chart with scenarios A, B, C-MV, and D to see how prices vary between periods. The only area presented is Sorland since the other areas show similar differences and can be found in Appendix H, 13.8.

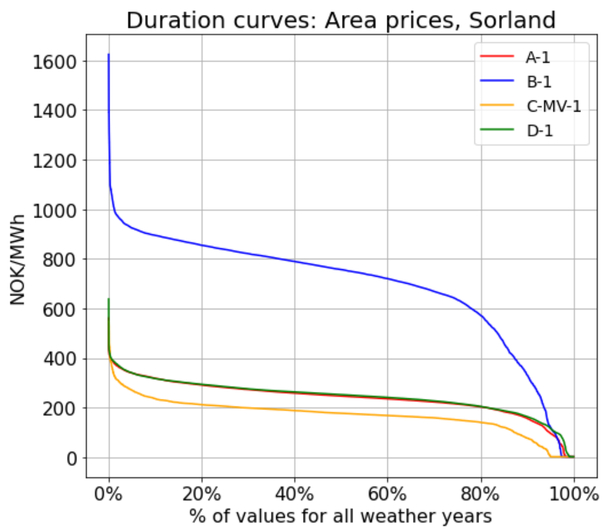

Figure 18: Duration curves for the area prices in Sorland for the different scenarios

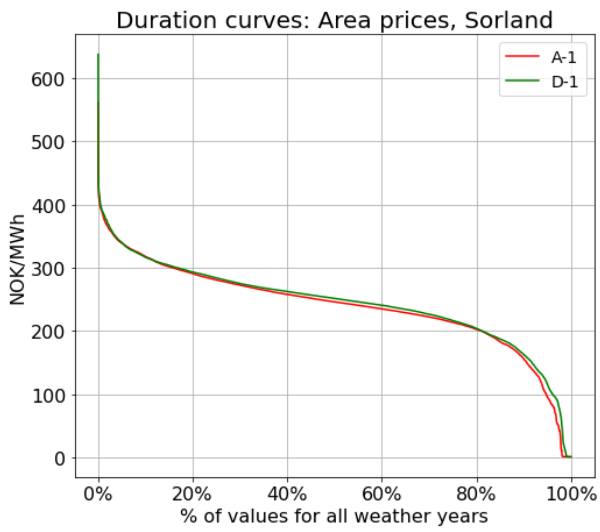

Figure 19: Duration curve for the area prices in Sorland for the scenarios A and D

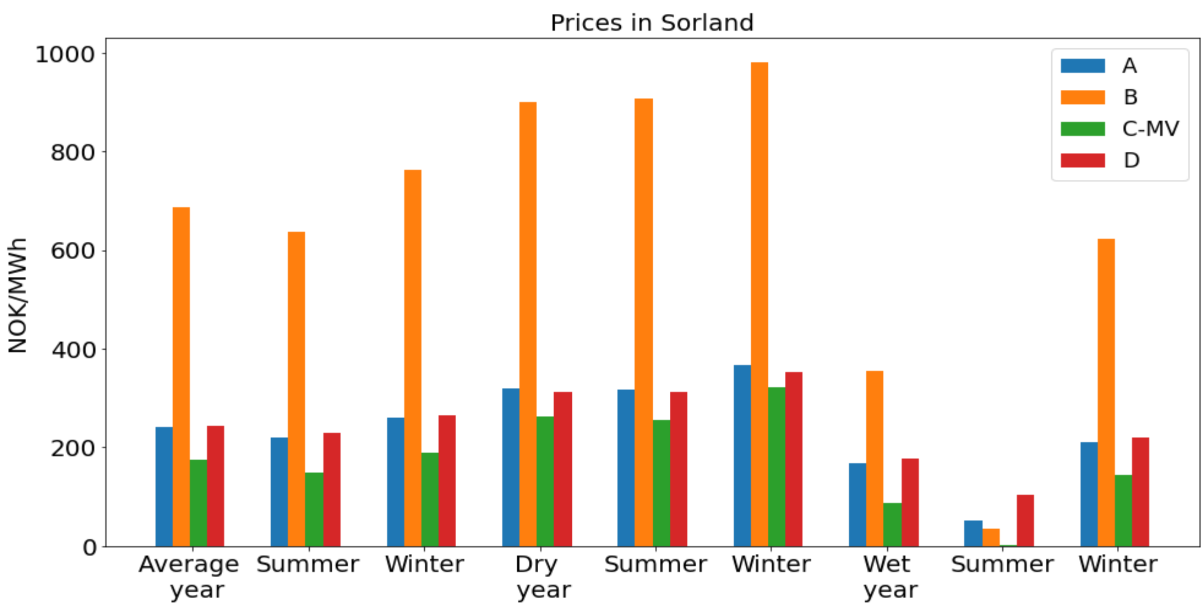

Figure 20: Bar chart for the average hourly area prices in Sorland for average-, dry- and wet year with seasonal differences

European areas

Table 5 presents the mean hourly area price for all weather years for Tysk-Nord and GB-Mid. These two areas give a indication of prices in Europe.

Table 5: Average hourly area prices for Tysk-Nord and GB-Mid

Areas	Price [NOK/MWh]			
	A-1	B-1	C-MV-1	D-1
Tysk-Nord	379,80	1179,74 **+799,94**	429,1 **+40,30**	372,37 **-7,43**
GB-Mid	293,17	1005,23 **+712,06**	320,07 **+26,90**	281,47 **-11,70**

Area differences

The mean hourly area prices for the areas Sorland, Sorost, Vestmidt, Norgemidt, and Finnmark are presented in the figure 21. The same bar chart for the other scenarios can be found in Appendix I, 13.9.

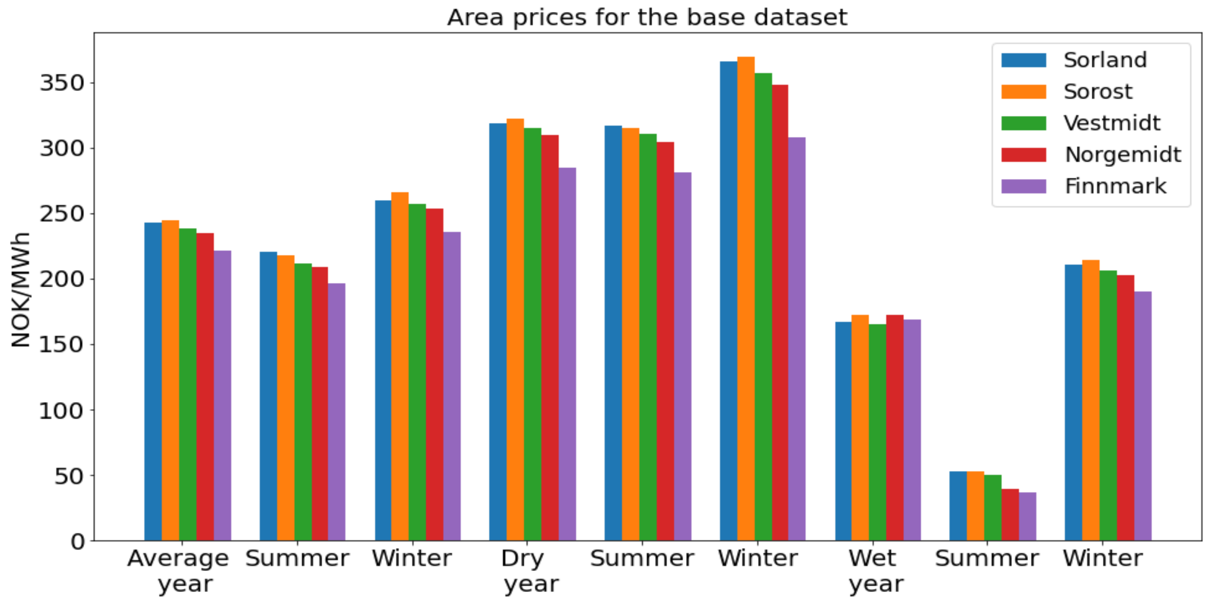

Figure 21: Bar chart for A-1 for the average hourly area prices in the areas for average-, dry- and wet year with seasonal differences

Dry year in South

To reflect the current European situation, one further investigates the area prices for 2005. In 2005 the difference in inflow between the Northern and the Southern parts of Norway was high. One uses the high fuel price scenario to compare this with the current area prices.

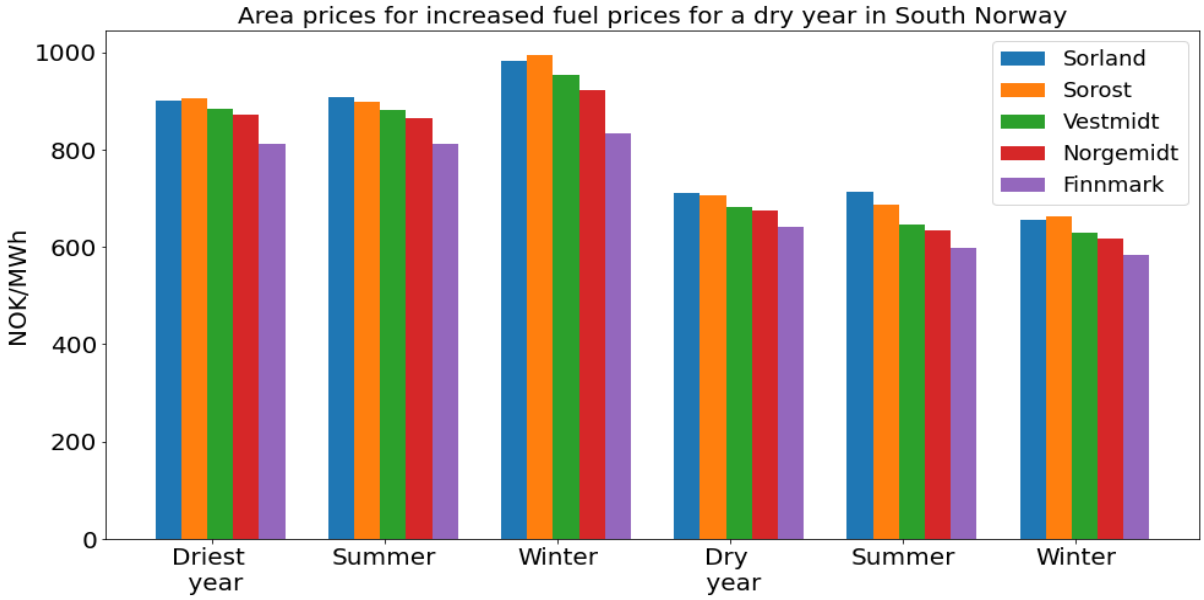

Figure 22: Bar chart for B-1 for the average hourly area prices in the areas for average- and dry year with seasonal differences

Figure 18 presents the duration curves for area prices in Sorland for the different scenarios. An observation is that the price for scenario B with high fuel prices lies substantially higher than the other curves while removing the subsea cables out of Norway gives lower values. The peak values for scenarios A, C, and D are similar. Increasing the capacity to Great Britain (Scenario D) gives relatively equal prices to the base dataset. On the other hand, one can from figure 19 observe an incremental increase, which coincides with NVE's assessment of the effect of NorthConnect [50].

Figure 20 presents the average area prices for an average year, a dry year, and a wet year, together with their seasonal differences for Sorland. Some general observations are how the area prices are higher for a dry year than the average year and how prices are significantly lower for a wet year. The figure shows the correlation between inflow and area prices and the fluctuations in prices between weather years.

When fuel prices are increased, the area prices for B are drastically higher than the rest. This coincides with the decrease in social welfare for the whole system, as discussed in part 7.1. For scenario C, removing the subsea cables from Norway, one can observe that the area prices in Norway are lower. The social welfare for this case, as mentioned in the previous part, is lower than for the base scenario. Looking at the area prices in the rest of the system in table 5, the prices for Tysk-Nord and GB-Mid increase in C. Removing the subsea cables from Norway leads to lower average Norwegian area prices. At the same time, prices increase in Europe, showing that the whole system does not benefit from this action.

Removing the subsea cables from Norway in scenario C does not indicate isolation of Norway from the European system. One has kept the transmission capacity to Sweden and Finland, meaning that Norway is not disconnected from the European system, although there is a reduction in export and import possibilities. NVE has done a study where Norway is completely disconnected from the European system, found in [51]. In this report, a finding is that the Norwegian prices would be two to three times higher without the connections to Europe. In part 10 of this thesis, one further investigates a situation where Norway is in scarcity while removing the subsea cables, and the result is higher Norwegian area prices. For the dataset used in this part, Norway is in a surplus state and still has connections to the European system. This situation leads to lower area prices in Norway relative to the base scenario. It is not further analyzed in this thesis if the isolation of Norway in terms of external cables will give higher area prices.

An observation of the Norwegian area prices is that for scenario D, looking at figure 20, the area prices are pretty similar to the base scenario. For a wet year, the area prices are slightly higher for scenario D, while in a dry year, Norway incrementally benefits as the area prices are a bit lower. From this, one can see that when Norway has a wet year, the increased capacity to Great Britain will increase the area prices. However, in a critical year, Norway will benefit from the strengthened connection. For the average prices in Tysk-Nord and GB-Mid, one can from table 5 see that the area prices decrease for scenario D. From table 4 it is also clear that the total social welfare increases compared to the base dataset for this scenario. This supports the importance of how Norway and the subsea cables are a vital part of the European system, contributing to handling the future energy demand.

From figure 21, one can observe how the average hourly prices vary between the selected areas in Norway. Finnmark has the lowest area price in all instances, except for the wet year, followed by Norgemidt and Vestmidt. Sorost and Sorland alternate between being the area with the highest average price through weather years and seasons. Sorland has a large share of hydropower and is sensitive to the corresponding inflow year. In addition, Sorland has tight couplings to continental Europe through several cables. From table 5, the average area prices in Tysk-Nord and GB-Mid are higher in comparison to the Norwegian prices. In figure 19, one can see a slight increase in the area prices when scaling up the capacity to Great Britain. Sorland is connected to Denmark, the Netherlands, Germany, and Great Britain, which affects the area price. This substantiates how the Norwegian area prices differ between the north and south. For a wet year, the difference is minor between the areas compared to the dry year when the price in Finnmark is significantly lower, which corresponds to the mentionings in part 2.5, and reflects the electricity prices today.

The last year, the prices in Norway's southern and northern parts have been very different. Low inflow in the south and high inflow in the north combined with high fuel prices have affected the power prices both in Europe and Norway. The dataset was further investigated to analyze a similar year, where the year with the most significant difference in inflow between Northern and Southern Norway was chosen. In figure 22, the dry year represents this year with high fuel prices and is compared to the driest year in the dataset for scenario B. One can observe that the differences in price between the north and south are higher in this figure than for figure 21.

Another factor that impacts the difference in prices between the north and the south is the capacity of the lines between the areas, which may not be adequate to even out the power prices. In reality, the capacity of the lines will be lower than what the model may take into account. An example is in the capacity between Norgemidt and Helgeland. In the dataset used in this thesis, the line has a capacity of 1710 MW. This is compared to the capacity between NO4 and NO3 in NordPool's market data. In a transmission capacity prognosis from the 9th of May until the 22nd of May in 2022, the line was given a capacity of 1200 MW. This may be the reason for the lower differences between the prices in the north and south in the simulations compared to last year's prices.

One can, from these results, conclude that the different cases will not necessarily affect the Norwegian and European area prices in the same way. The weather years have a tremendous impact on the power prices, contributing to low prices in wet years and high area prices when the reservoir levels are low. In addition, the inflow may affect prices differently in the north and south of Norway. Increasing the fuel prices leads to a drastic rise in all area prices, while disconnecting the subsea cables from Norway leads to lower Norwegian area prices, given the country is in surplus. On the other hand, Europe will suffer from higher area prices as a cause of using other resources to cover their demand. When increasing the capacity to Great Britain, the effect on the Norwegian area prices is dependent on the weather year. Both scenarios C and D show the importance of renewable contributions from Norway through subsea cables.

7.3 Transmission

Areas in surplus and deficit

Figure 23 shows the power balance for the different areas in the system. A red area is in a deficit situation where the production is less than the firm demand, while a green area is in a surplus situation. The number shows the surplus or deficit yearly production in TWh for the area.

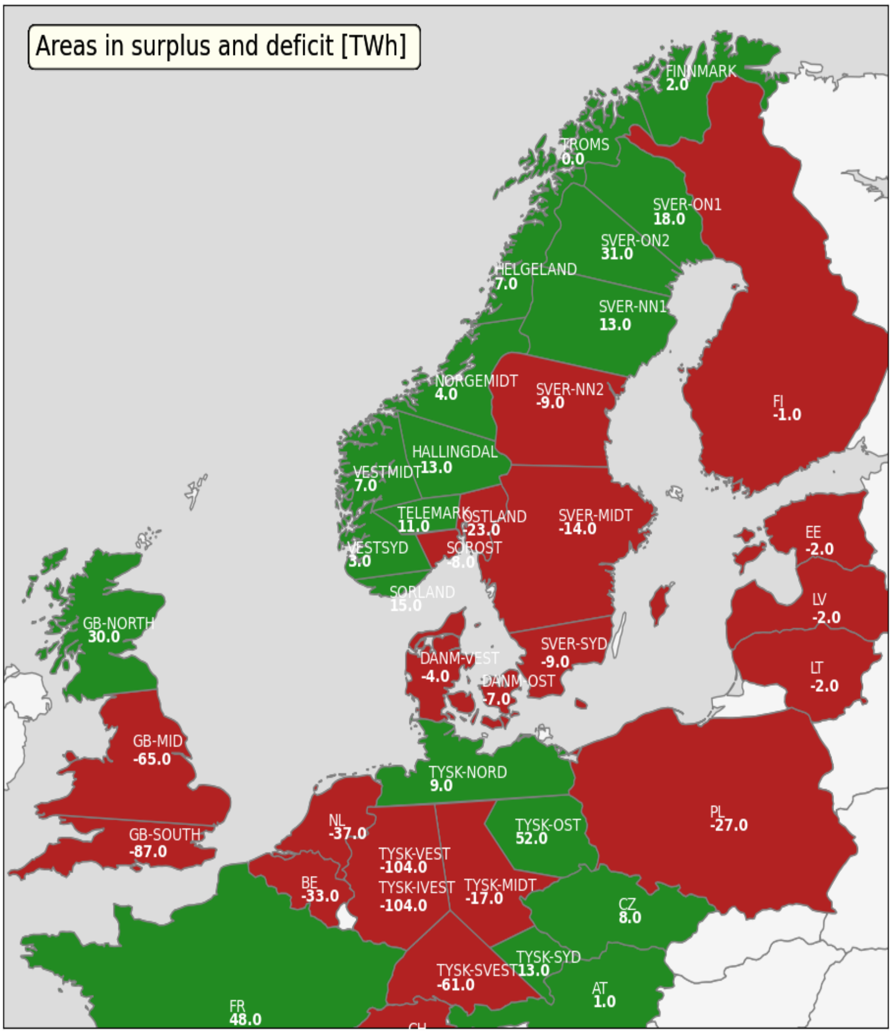

Figure 23: Average yearly production minus average yearly firm demand in TWh for A-1

Flow on external lines

The figures 24 to 28 present duration curves for all the values of the flow on the lines from Sorland to Danm-Vest, Sorland to Nederland, Sorland to Tysk-Nord, Vestsyd to GB-Mid and Vestmidt to GB-North for all weather years. The curves show the cases A-1, B-1 and D-1. Positive values represent export from Norway, while negative values represent imports.

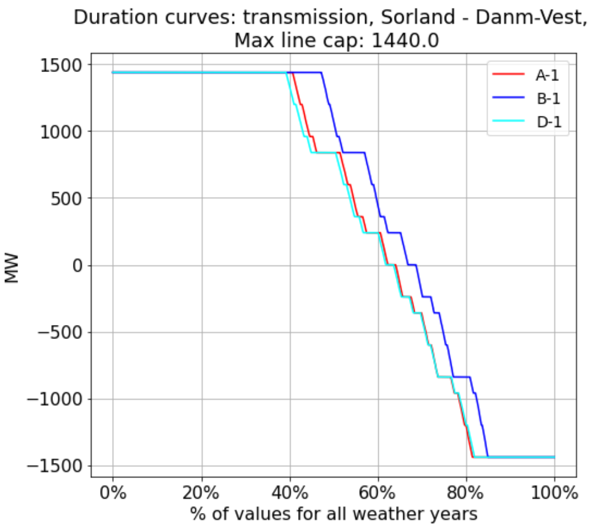

Figure 24: Flow on the line from Sorland to Danm-Vest for the different scenarios

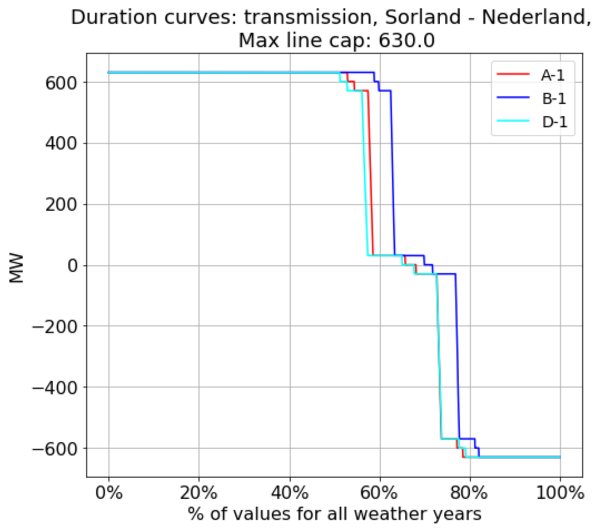

Figure 25: Flow on the line from Sorland to Nederland for the different scenarios

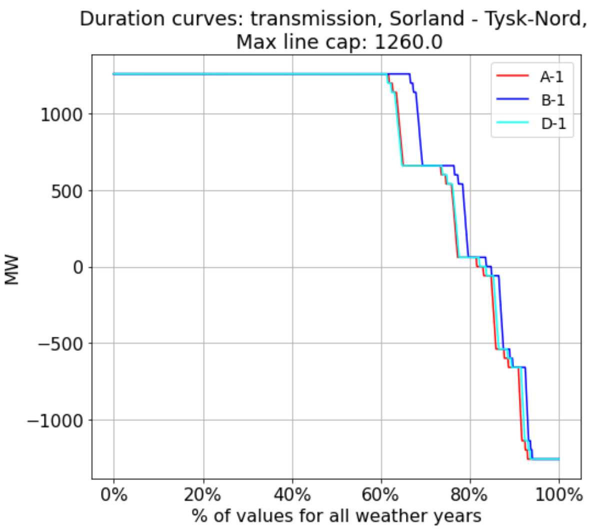

Figure 26: Flow on the line from Sorland to Tysk-Nord for the different scenarios

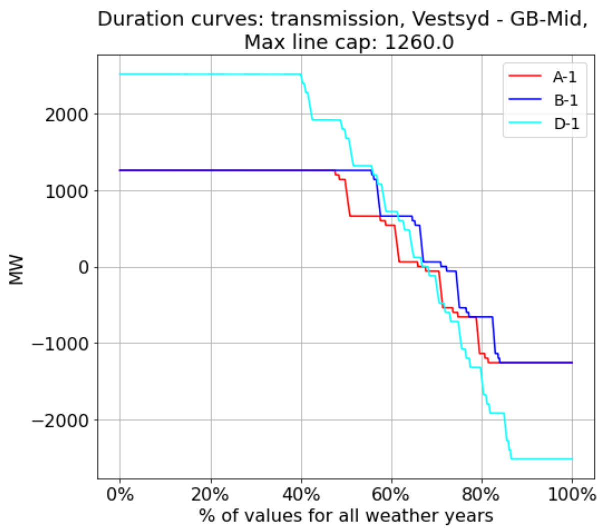

Figure 27: Flow on the line from Vestsyd to GB-Mid for the different scenarios

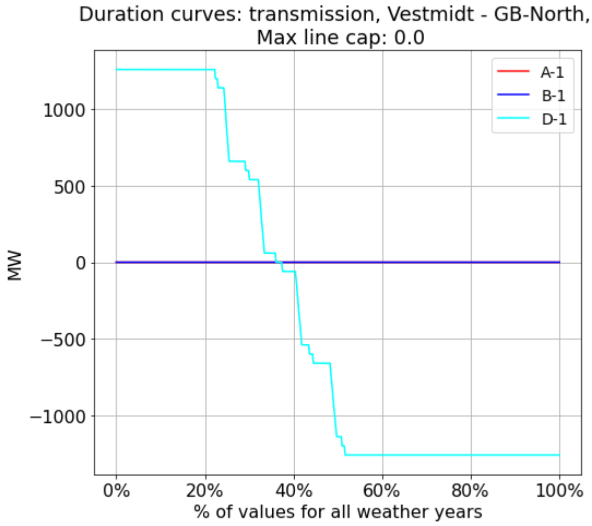

Figure 28: Flow on the line from Vestmidt to GB-North for the different scenarios

Map 23 presents the yearly average surplus or deficit production of the areas in Europe, while the duration curves in the figures 24 to 28 present the flows on the subsea cables between Norway and Europe.

From the area map in 23, one can see that Denmark, Germany, Great Britain, and the Netherlands are, on average, in deficit and therefore needs to import. For all cables, except Vestmidt to GB-North, a general observation is that Norway exports more than the amount imported. For scenario B, exports are more extensive than in the base case. As the price of thermal assets increases, renewable assets are preferred. External cables will also reflect price signals dependent on the situation in different areas, which coincides with the higher area prices in Norway for scenario B, observed in part 7.2.

For scenario D, one can see a decrease in the export on the lines from Sorland to Danm-Vest, Sorland to Nederland, and Sorland to Tysk-Nord. The export amount increases from Vestsyd to GB-Mid and from Vestmidt to GB-North due to the increase in capacity on these cables. From this, one can see how energy is dispatched when scaling up the capacity to Great Britain. The decrease in export on the other cables shows how an increase to Great Britain leads to better exploitation of the cheaper power. The increase gives lower price differences and, therefore, a lower amount of export, as one exports from an area with a lower price to an area with a higher price. The increase in social welfare for scenario D substantiates how these cables are favorable for society.

Overall, Norway exports more electricity than is imported due to low area prices. When the power prices in Europe are increased because of high fuel prices, the external cables are more valued, supporting the claim that Norwegian hydropower plays a vital role in the European power market.

Marginal congestion rent

In table 6, the average marginal congestion rents for five subsea cables connected to Norway are presented for the different cases A-1 to D-1. Congestion rent equals the difference between payments made by loads and exports and the revenues received by generators and imports [60]. The marginal congestion rent makes up the dual value of the transmission constraint.

Table 6: Average marginal congestion rent for the subsea cables connected to Norway

Line/ Capacity	Marginal congestion rent kNOK/MW/year			
	A-1	**B-1**	**C-MV-1**	**D-1**
Sorland - Danm-Vest (Cross-Skagerrak) 1440 MW	1228,54	4326,73 +**3098,19**	2209,15 +**980,61**	1078,84 **-149,7**
Sorland - Tysk-Nord (NordLink) 1260 MW	1749,76	5414,20 +**3665,44**	2611,93 +**862,17**	1621,14 **-128,62**
Sorland - Nederland (NorNed) 630 MW	1401,95	5197,22 +**3795,27**	2021,47 +**619,52**	1226,70 **-175,25**
Vest-Syd - GB-Mid (North sea link) 1260 MW	1374,34	5112,94 +**3738,60**	1949,02 +**574,68**	1184,79 **-189,55**
Vestmidt - GB-North (NorthConnect) 0 MW	1729,16	5523,639 +**3794,48**	1843,12 +**113,96**	1527,46 **-201,70**

Marginal congestion rent is the marginal income a transmission system operator gets from trade on a transmission line between two areas. When there is an expansion or a capacity increase between areas in the power system, the system operator loses bottleneck income. On the contrary, the following price balance between areas will increase producer- and consumer surplus. The internal bottleneck incomes can therefore be interpreted as an unrealized producer- and consumer surplus as a cause of restrictions in the transmission system [50].

For all the different cables in table 6, one can observe that scenario B-1 has the highest marginal congestion rents. Following B-1 are the values for C and the values for A. In scenario D, capacity is added through North Sea Link and NorthConnect, leading to an equalization of prices between Norway and the European areas. As a result, the marginal congestion rent decreases compared to the base scenario. Scenario B, when fuel prices are high, is the scenario that leads to the most significant price differences between areas. The cable with the highest marginal congestion rent for this scenario is Sorland-Tysk-Nord, also known as NordLink.

An assessment is conducted to investigate the benefit of this cable. The yearly investment cost for NordLink with a discount rate of 3% and a lifetime of 40 years is calculated to be 735,46 MNOK. For the 30 different inflow years, the average yearly bottleneck income for NordLink is calculated to be 2051,56 MNOK. This is around 2,8 times the investment cost. To analyze the possible effect on social welfare, inspiration from an assessment done by NVE on NorthConnect is used [50]. Some parameters are priced to assess the benefit in social welfare when adding a cable. The assessment accounts for changes in spot trading income and income from the capacity market to calculate income.

On the other hand, the costs included are the investment cost of the cable, maintenance and operation costs, and costs for changes in the system operation. The assessment done by NVE concludes that NorthConnect most likely is a beneficial contribution to social welfare, with an estimated increase of 8485 MNOK [50]. The biggest cost in the equation is the investment cost, and based on the estimates for the other costs and incomes, one can assume that NordLink will also increase the social welfare of the system. Adding an extra MW of capacity on this line gives an increase of 0,525 MNOK to the yearly investment cost. Based on the arguments in this section, one can assume that this will be valuable for the system in total.

7.4 Reservoir level

This part presents the reservoir levels in percentiles for Blåsjø and Frøystøl. Blåsjø is the biggest reservoir in Norway, with a reservoir volume of 3105 Mm^3. The changes in scenarios and water values will have a more considerable impact on the biggest reservoirs, which is the reason for presenting Blåsjø. Blåsjø is often used as an indicator to see if the long-term utilization of water is modeled correctly. Frøystøl is the second reservoir presented. This is a smaller reservoir compared to Blåsjø. The figures presented show the 0-, 50-, and 100-percentiles based on values for all weather years for Blåsjø and Frøystøl, where each plot presents the difference between two different cases, for example, A-1 and C-MV-1. Reservoir levels for Nore 1 and Vrenga can be found in Appendix J, 13.10. Nore 1 is smaller than Frøystøl, and Vrenga is even smaller. These reservoirs are selected to see how the change in scenarios affects different reservoirs.

Scenarios A and C-MV

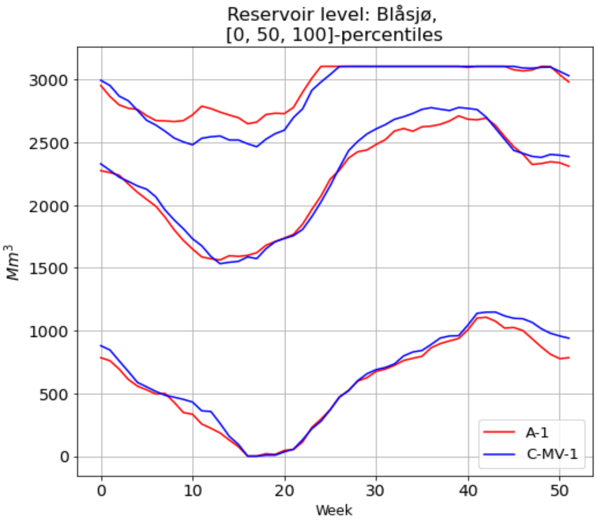

Figure 29: 0-, 50-, 100-percentiles for the reservoir level for Blåsjø for scenarios A and C-MV

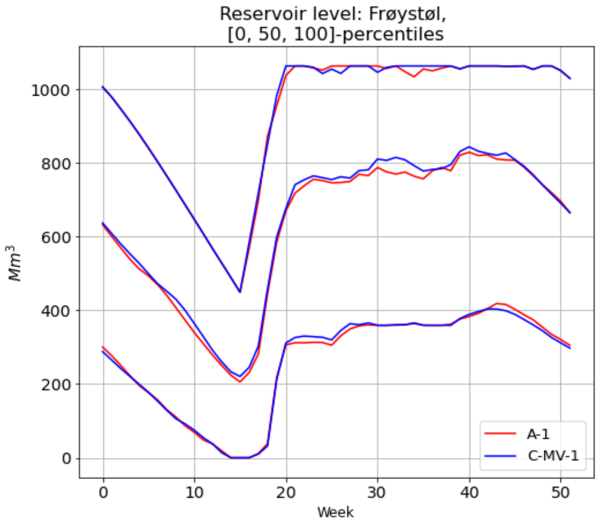

Figure 30: 0-, 50-, 100-percentiles for the reservoir level for Frøystøl for scenarios A and C-MV

Scenarios C-MV and D

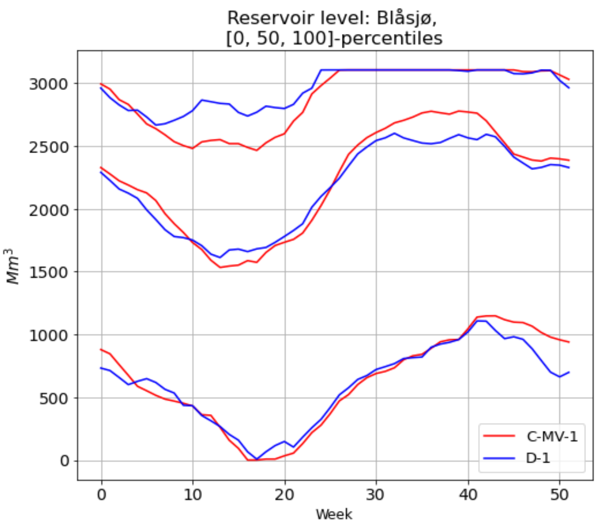

Figure 31: 0-, 50-, 100-percentiles for the reservoir level for Blåsjø for scenarios C-MV and D

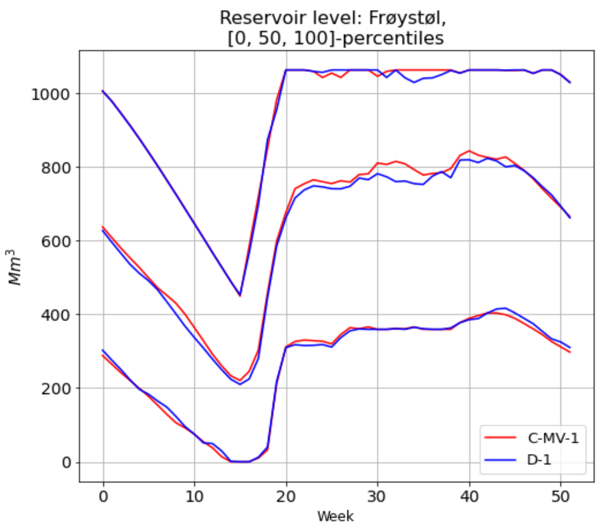

Figure 32: 0-, 50-, 100-percentiles for the reservoir level for Frøystøl for scenarios C-MV and D

Figure 29 presents the 0-, 50-, and 100-percentile for Blåsjø, where the red line represents A-1 and the blue line C-MV-1. One can from the figure observe how the 100-percentile for A-1 lies a little higher than for C-MV-1, meaning more water is used for C. The amount of flooding is slightly less for C-MV-1. The time the 0 -

percentiles lie at 0 Mm^3 is also the same. However, the red curves for A-1 have some lower values for the 0- and 50-percentile than C-MV-1.

Looking at figure 31, presenting the cases C-MV-1 and D-1, one can observe how Blåsjø in scenario C-MV-1, when removing the subsea cables from Norway, utilizes the reservoir storage capacity to a larger extent compared to D. One can observe that the percentiles for C has the lowest and the highest values. The curve for D, increasing the capacity to Great Britain, has more even values over time. It is clear from the 0-percentile that there is more rationing for C-MV-1, which is logical since the subsea cables are removed and more water is exploited. In the 100-percentile in figure 31, one can observe how the curve for scenario C is at a lower level, meaning more water is used. The amount of flooding does not seem to be significantly affected by the different scenarios.

The percentile curves for Frøystøl, a smaller reservoir, are found in figure 30 and 32. One can observe that all percentiles are pretty similar, meaning the different scenarios do not seem to affect the usage of water in a significant way for smaller reservoirs. The percentile curves for the other, even smaller reservoirs, do not show any significant differences between scenarios as the changes shown represent small volumes. Therefore they are not presented nor discussed. A selection of these figures can, as previously mentioned, be found in Appendix J, 13.10.

7.5 Recalculating end water values

In this thesis, the original dataset, dataset A, was reasonably well calibrated, and the EMPS end water values were considered sufficient. In the other scenarios, B-D, substantial changes are done to the dataset, which means one would expect the "optimal" end water values to change. An option when running FanSi is to update the end water values. One has created two scenarios to analyze the effect of updating these water values when changes are done to the dataset: C-UV and C-MV. In C-UV, the end water values are not recalculated while they are in C-MV. For both scenarios, the subsea cables from Norway are given a capacity of 0. This part presents all the different results before a collective discussion at the end.

Social welfare
Table 7 presents the average social welfare for C-UV and C-MV for parametrizations 1-5. The + and - in the C-MV row represents the difference between C-MV and C-UV. A + represents a higher number for C-MV, while a - represents a lower number.

Table 7: Average social welfare for C-UV and C-MV

	Social welfare [Mkr]				
	C-UV-1	**C-UV-2**	**C-UV-3**	**C-UV-4**	**C-UV-5**
Total	64609729,16	64609999,36	64610203,19	64609661,22	64609296,74
	C-MV-1	**C-MV-2**	**C-MV-3**	**C-MV-4**	**C-MV-5**
	64609980,60	64610223,95	64610347,32	64609633,75	64609222,50
	+251,44	**+224,59**	**+144,13**	**-27,47**	**-74,24**

Area prices

The figures 33-35 present the duration curves for the cases C-MV-1 and C-UV-1 for the areas Sorland, Sorost, and Finnmark. They are presented to see how the area prices are affected by recalculating the end water values.

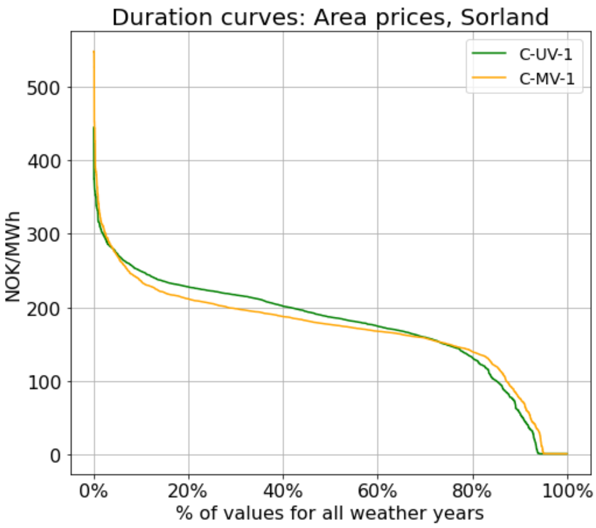

Figure 33: Duration curves for the area prices for Sorland for C-UV-1 and C-MV-1

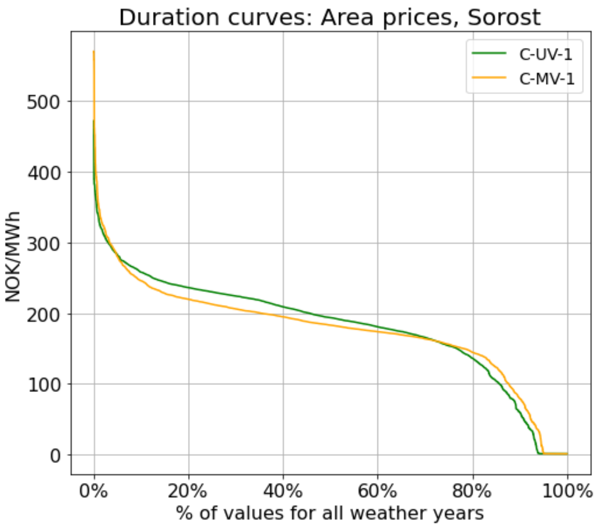

Figure 34: Duration curves for the area prices for Sorost for C-UV-1 and C-MV-1

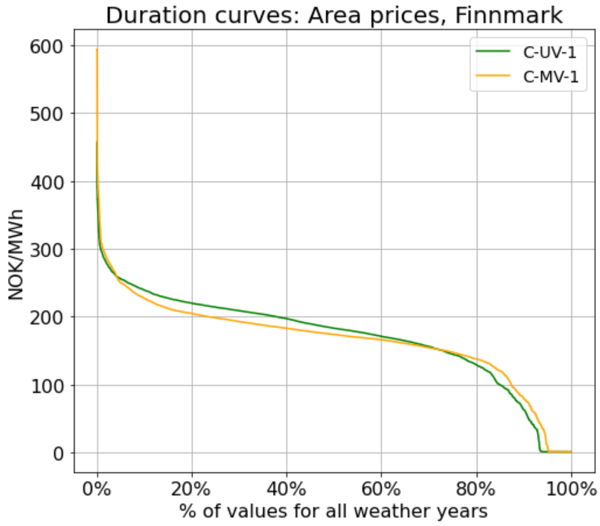

Figure 35: Duration curves for the area prices for Finnmark for C-UV-1 and C-MV-1

Reservoir level

Figures 36-39 presents the percentiles for the reservoir level for C-UV-1 and C-MV-1 for the reservoirs Blåsjø, Frøystøl, Nore 1 and Vrenga. The percentiles are based on all the values for the different weather years. As mentioned in part 4.6, it is mainly the larger reservoirs which are affected by the end value settings. Looking at Blåsjø, the biggest reservoir in the dataset, one can clearly see the difference between the percentiles for the two scenarios.

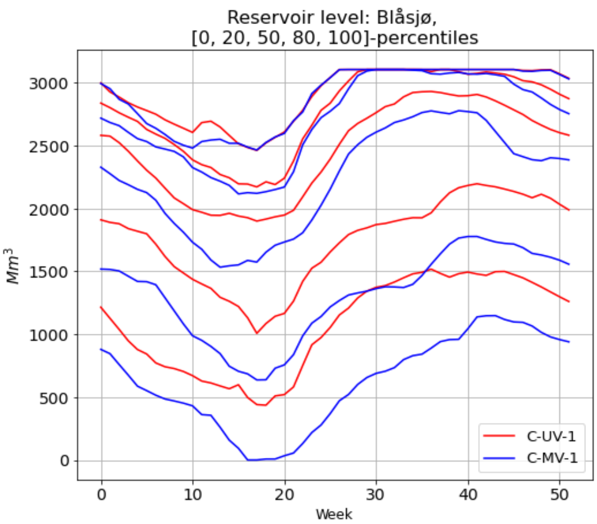

Figure 36: Percentiles for the reservoir level for C-UV-1 and C-MV-1 for Blåsjø

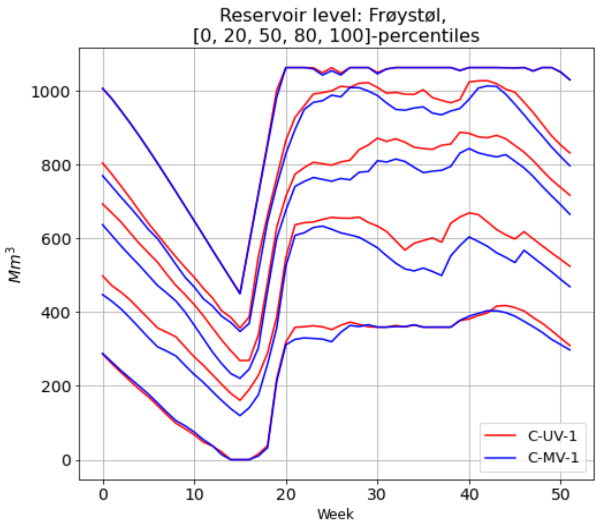

Figure 37: Percentiles for the reservoir level for C-UV-1 and C-MV-1 for Frøystøl

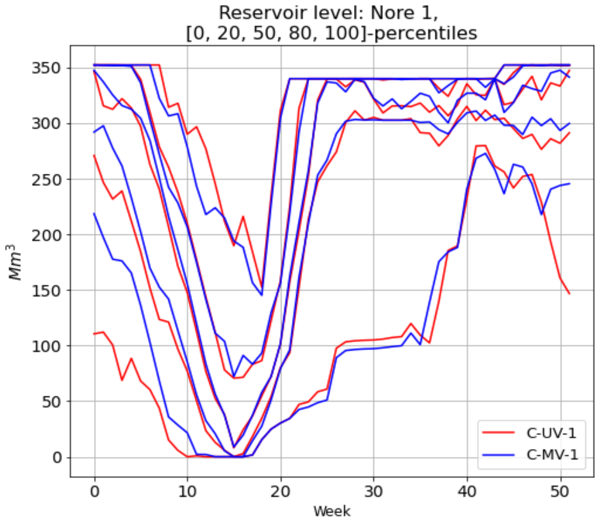

Figure 38: Percentiles for the reservoir level for C-UV-1 and C-MV-1 for Nore 1

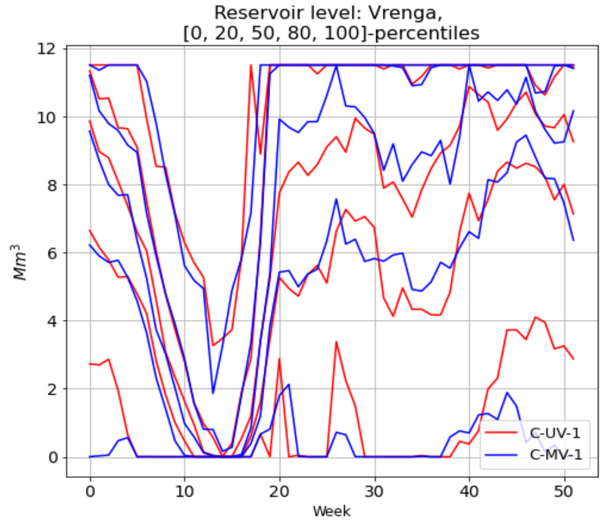

Figure 39: Percentiles for the reservoir level for C-UV-1 and C-MV-1 for Vrenga

Long time horizon

Figure 40 and 41 presents the duration curves for area prices and the percentiles for the reservoir levels for C-UV-5 and C-MV-5. These are presented to see if the effect of calculating new end water values and not recalculating the end water values diminishes with a long time horizon.

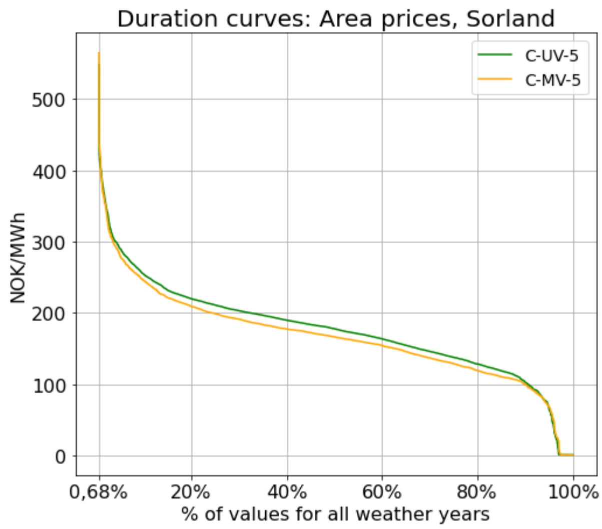

Figure 40: Duration curves for the area prices for C-UV-5 and C-MV-5 for Sorland

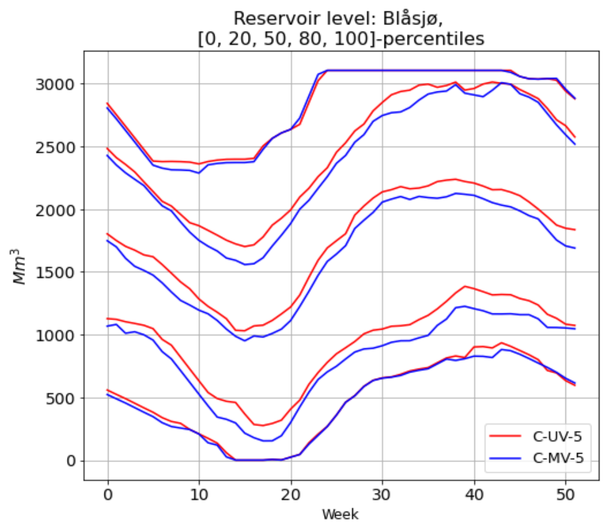

Figure 41: Percentiles for the reservoir level for C-UV-5 and C-MV-5 for Blåsjø

Discussion
The assumption is that when changes are done to a dataset and the end values are not recalculated, the end water values will be too high, resulting in poor water utilization in the reservoirs. Therefore, the expectation is that updating the end water values will lead to lower reservoir levels, better utilization of water, and lower area prices. For production planning with models like FanSi, the model will try to empty the reservoirs. If a simulation has a short time horizon, big reservoirs need an end value to prevent being emptied in a short time. The end values are less important when a long time horizon is used. Therefore, it is also assumed that the differences between C-UV and C-MV diminish with a longer time horizon. Due to a weakness in the calculation of social welfare, further explained in part 8.2, the difference in social welfare between the -4 and -5 parametrizations is not assessed.

In the figures 36-39, percentiles for the reservoir levels for the reservoirs Blåsjø, Frøystøl, Nore 1 and Vrenga are presented for both C-MV-1 and C-UV-1. The most significant difference between the percentiles for C-MV-1 and C-UV-1 can be seen in Blåsjø, which is the largest reservoir in Norway. The smaller the reservoir, the smaller the differences are between the percentiles in terms of volume. This confirms that updating the end values is more important for larger reservoirs.

When looking at the 0 - percentile for C-UV-1 in 36, it is far from the 0-percentile for C-MV-1. The high end water values do not allow more utilization of water, as reservoir levels are kept high to satisfy the end value. The reservoir levels are generally lower for C-MV-1 than for C-UV-1, showing better utilization of water. This coincides with the lower area prices and the higher social welfare for C-MV-1 compared to C-UV-1. The 100-percentiles for both scenarios are pretty similar, leading to the same amount of spillage.

From the social welfare in table 7, one can observe that the value for C-MV is higher than for C-UV for the first three parametrizations. For the parametrizations -4 and -5, C-UV values are higher than C-MV, but the difference diminishes. From the duration curves in figures 33-35, one can also observe that the area prices for C-MV are lower than for C-UV, while the peak value of the curve is higher for C-MV. One can from this conclude that recalculating the end water values gives better results. The differences are minor, but it is beneficial when a dataset is changed.

An expectation is that the end water valuation will be less critical for longer time horizons, and that the difference between C-MV and C-UV will diminish. From figure 40, it can be observed how the difference in duration curves between C-UV-5 and C-MV-5 is smaller than the difference between C-UV-1 and C-MV-1 in figure 33. It is also clear from figure 41, that the difference in the percentiles for Blåsjø is smaller for C-UV-5 and C-MV-5 than between C-UV-1 and C-MV-1 in figure 36. It can still be seen how a recalculation of end water values gives lower area prices and better water disposal, although the effect decreases.

One important remark is that the end water values are calculated using the EMPS model. For the instances, in this case, these values are not calibrated, leading to uncertainty about how accurate the new values are. To achieve a good end valuation, calibration must be done to handle factors for different price areas that reflect the world's current state. To do this, one needs experience. The results show that recalculating the end water values gives a better simulation for the dataset, but one could achieve a better end valuation by calibration.

7.6 Main points

This section handles the differences between the scenarios and how they affect the simulated operations of the system. It investigates social welfare, area prices, reservoir levels, marginal congestion rent, and flow on subsea cables.

From the discussion, the key points are:

- Increasing the fuel prices (Scenario B), as expected, leads to lower social welfare for the system, where the producer surplus increases and the consumer surplus decreases, reflected in higher area prices both in Norway and Europe. The export from Norway increases for scenario B, substantiating how the Norwegian hydropower is an important contribution to the system.

- Removing the subsea cables from Norway (Scenario C) leads to lower social welfare for the whole system. Meaning it does not benefit the European power market. This correlates to the higher area prices for Tysk-Nord and GB-Mid in scenario C. The area prices in Norway , however, decrease, meaning the area prices in Norway can benefit when being in a surplus. The consumer surplus experiences an increase while the producer surplus decreases in Norway, while the situation is the opposite for the total system. This shows that different scenarios will not necessarily have the same impact on all areas and countries in the system.

- When increasing the capacity to Great Britain (Scenario D), the social welfare for the system increases, and the prices for Tysk-Nord and GB-Mid are slightly reduced, while the area prices in Norway have a slight increase relative to the base scenario. The Norwegian producers benefit from the subsea cables. At the same time, Norwegian consumers pay a higher cost. On the other hand, in a dry year, Norway has a slight reduction in area prices for scenario D. One can from this conclude that the increase in capacity is beneficial for the system as a whole and for the prices in Europe but will not necessarily have a significant impact on the Norwegian power prices. These results substantiate the claim that the subsea cables are important for Northern Europe.

- The marginal congestion rents on the subsea cables are positive for all scenarios and simulations, meaning more capacity would benefit the system. The highest value is found for the scenario where fuel prices are increased, as this scenario leads to the highest price differences between areas. Based on an assessment related to the benefit of an increase on NordLink related to this scenario, the conclusion is that this would be valuable for Northern Europe in terms of social welfare. When increasing the capacity to Great Britain, the marginal congestion rent decreases compared to the base case due to the equalization of prices between Norway and the European areas.

- From the reservoir curves, it is found that the capacity is stretched both up and downwards when the subsea cables out of Norway are removed, while the water is more evenly distributed when the capacity to Great Britain is increased. None of the scenarios seems to have a large impact on the amount of flooding and rationing. For the smaller reservoirs, the differences between the curves are related to smaller volumes, showing how changes for these does not largely affect the results.

- Recalculating the end water values will give a better simulation, where the social welfare is higher, the area prices are lower, and where the utilization of water is better optimized. The differences diminish when using a long time horizon. The uncertainty in how good the recalculated values are can be discussed. However, even though the values are not calibrated, the new end water values give a better simulation and production plan.

As expected, the changes to the dataset will have an effect on social welfare, area prices, import and export, and the exploitation of water. An increase in fuel prices will have a negative effect on the system, where the social welfare decreases and the area prices increase, as seen in the last year. It is clear from scenarios C and D, removing the subsea cables and increasing the capacity to Great Britain, that Norwegian hydropower is an important part of the European power system. As a result, this resource paves the way for utilizing more variable renewable energy as hydropower offers cheap flexibility to the market, leading to a more stable system.

8 Parametrization

In 4.4 it is specified that FanSi is run through a control input file. The user has the opportunity to affect the simulation process by changing the input parameters given in this file. As written in part 1.2, FanSi is not yet in operative use but is used as a tool in research projects.

An essential aspect to better the utilization of FanSi is to investigate optimal parametrizations dependent on scenarios. A contribution to this research is made in this master thesis by analyzing how different parameters influence the results. The choice of parameters is based on decisions compromising run time and resource use with the quality of the results. The study of parametrizations is in this thesis conducted through analyzing different parametrizations on a dataset run with different scenarios.

The selection of parameters used for each scenario is described in section 6. This thesis focuses on two parameters: the number of scenarios and weeks used in the scenario fan. The role of the scenarios is to determine a strategy through water values, which affect the optimization. At the same time, the number of weeks secures a long enough planning horizon for the simulations.

8.1 Inflow for scenario reduction years

This part presents the inflow years chosen by the scenario reduction algorithm. The selected years shown are for the areas Vestsyd, Ostland, Finnmark, and GB-Mid for week 19 for A-1 to A-6. The boldness of the curves correlates with the probability chosen by FanSi for the inflow year. These graphs are presented to see how different parametrizations select inflow scenarios. In addition to how well the different parametrizations represent weather years. For cases A-1, A-4, and A-5, 4 scenarios are chosen, while the scenario fan's time horizon is 52, 104, and 156 weeks. For A-2 and A-3, 10 and 20 scenarios are chosen with a length of 52 weeks. While in A-6, 20 scenarios with a time horizon of 104 weeks are selected. In A-4, A-5, and A-6, the scenario length extends to two and three years. Therefore, the chosen inflow curves are based on the total energy of inflow and wind- and solar energy for seemingly two and three consecutive years in these parametrizations.

The scenarios shown are the inflow data and not FanSi's perception of the scenarios. In FanSi, a smoothing of the curves will be done to gradually increase the expected inflow relative to its starting point for the selected week. The inflow data is shown with a starting point at week 19, as this is a critical time. This is a week in the spring before inflow increases, so the reservoir levels are low.

As FanSi uses a scenario value, discussed in 4.3, to select scenarios, changes in the dataset that do not change the amount of inflow, wind, or solar energy will not affect the scenario reduction. Therefore, the same inflow scenarios are chosen for the other datasets for the same parametrizations. As a result, only curves for dataset A are presented.

For this part of the analysis, the areas selected to present the results are Vestsyd, Ostland, Finnmark, and GB-Mid. Vestsyd is chosen due to its large amount of hydropower, Ostland because it represents an area with high demand, and Finnmark because it is an area with lower prices in the north of Norway. Together with these, one has added GB-Mid to represent another European hydro-based area.

A-1

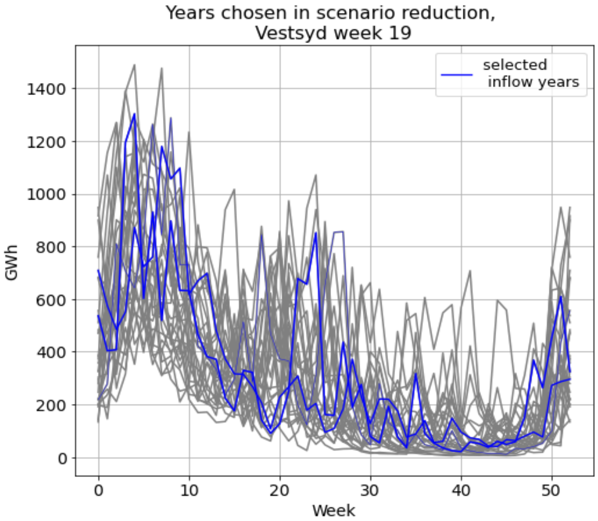

Figure 42: Inflow for the scenarios chosen in week 19 for Vestsyd for A-1

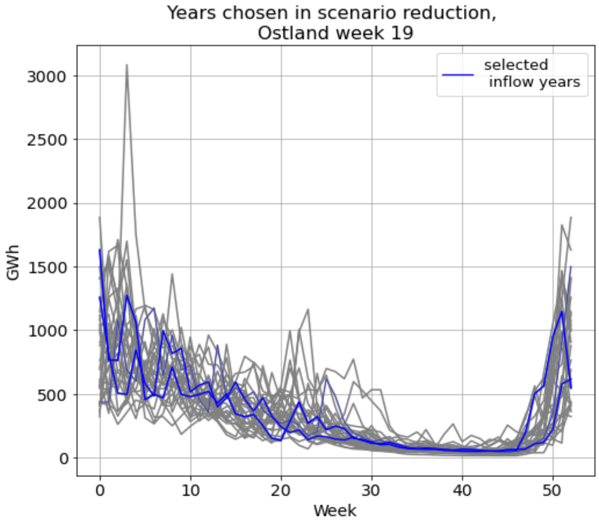

Figure 43: Inflow for the scenarios chosen in week 19 for Ostland for A-1

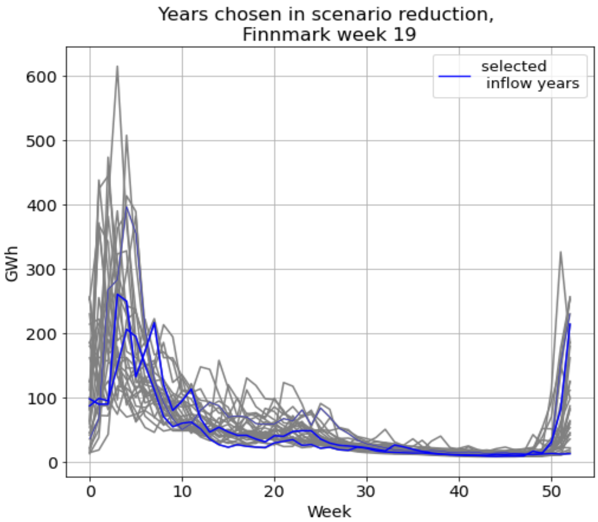

Figure 44: Inflow for the scenarios chosen in week 19 for Finnmark for A-1

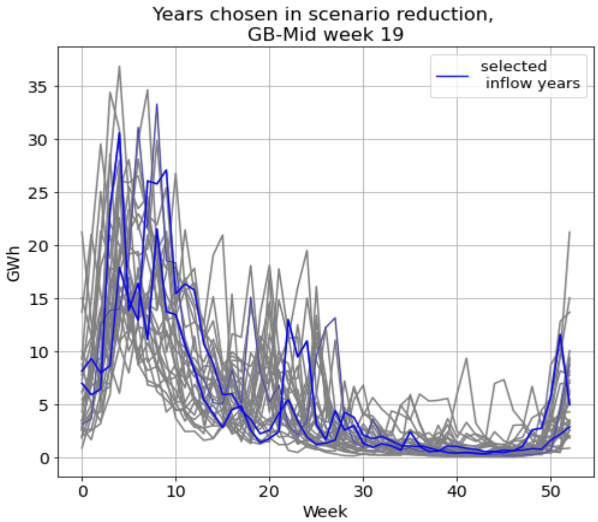

Figure 45: Inflow for the scenarios chosen in week 19 for GB-Mid for A-1

A-2

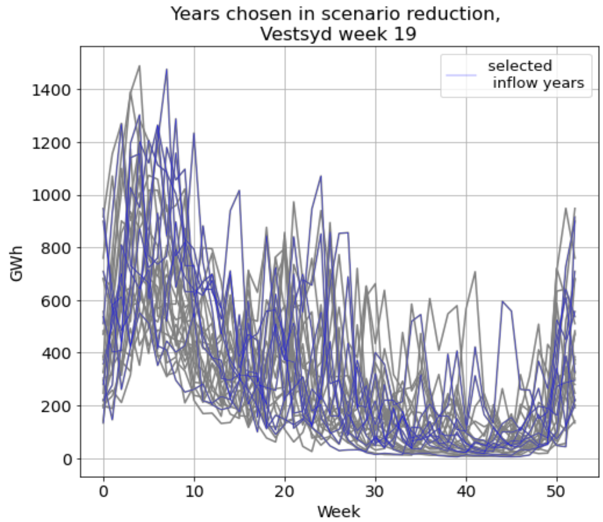

Figure 46: Inflow for the scenarios chosen in week 19 for Vestsyd for A-2

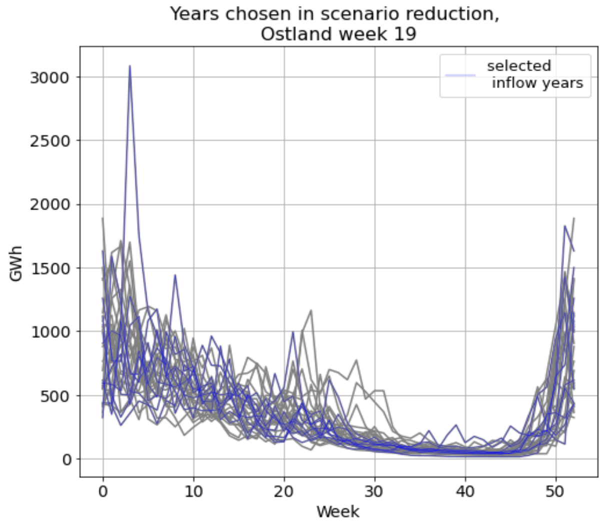

Figure 47: Inflow for the scenarios chosen in week 19 for Ostland for A-2

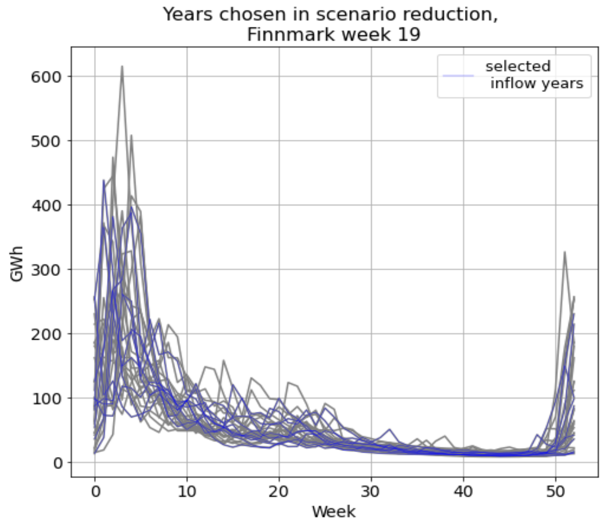

Figure 48: Inflow for the scenarios chosen in week 19 for Finnmark for A-2

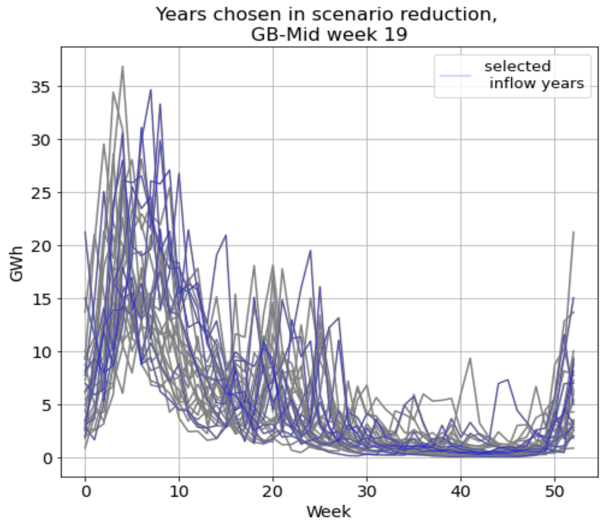

Figure 49: Inflow for the scenarios chosen in week 19 for GB-Mid for A-2

A-3

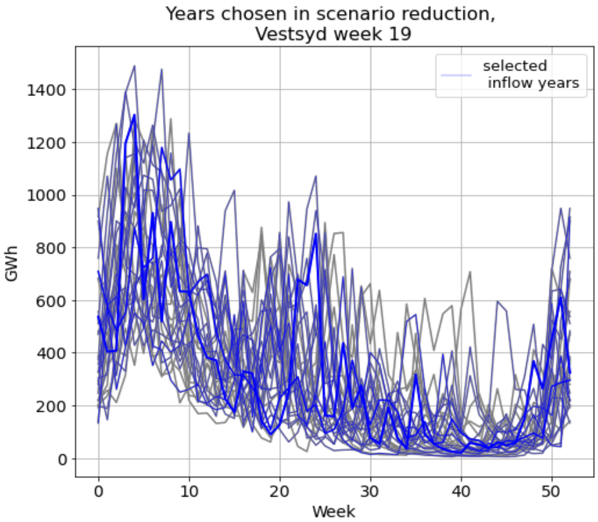

Figure 50: Inflow for the scenarios chosen in week 19 for Vestsyd for A-3

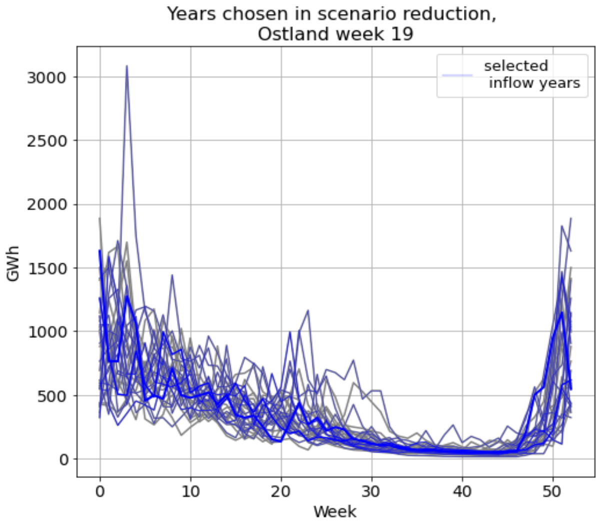

Figure 51: Inflow for the scenarios chosen in week 19 for Ostland for A-3

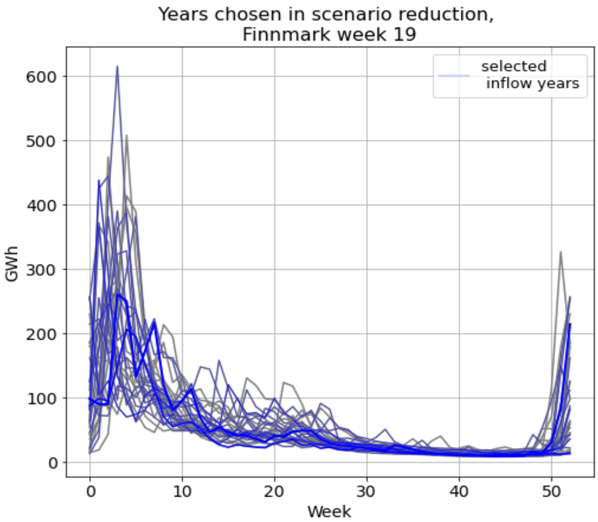

Figure 52: Inflow for the scenarios chosen in week 19 for Finnmark for A-3

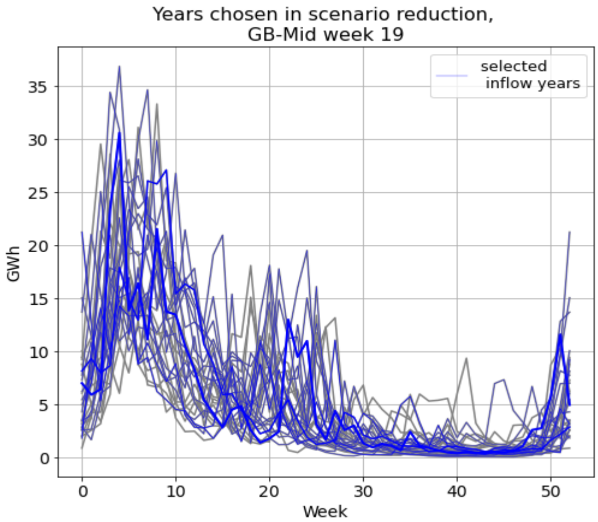

Figure 53: Inflow for the scenarios chosen in week 19 for GB-Mid for A-3

A-4

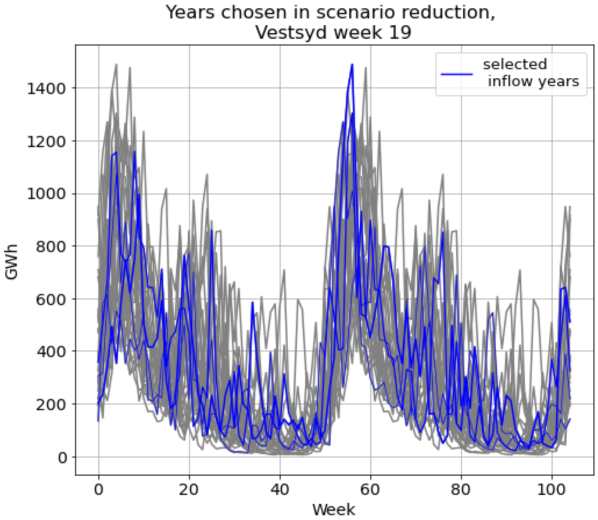

Figure 54: Inflow for the scenarios chosen in week 19 for Vestsyd for A-4

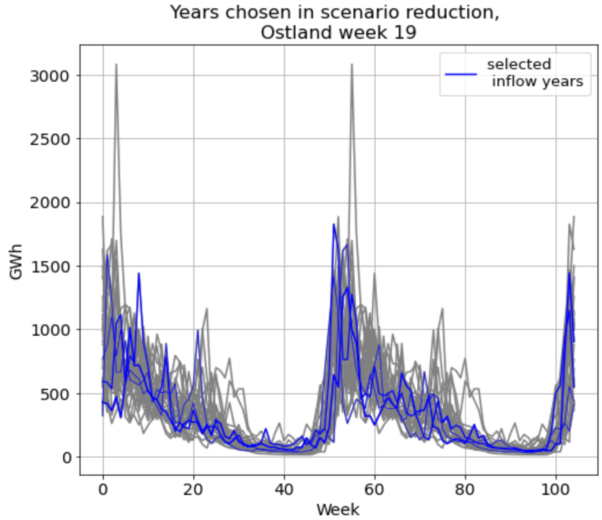

Figure 55: Inflow for the scenarios chosen in week 19 for Ostland for A-4

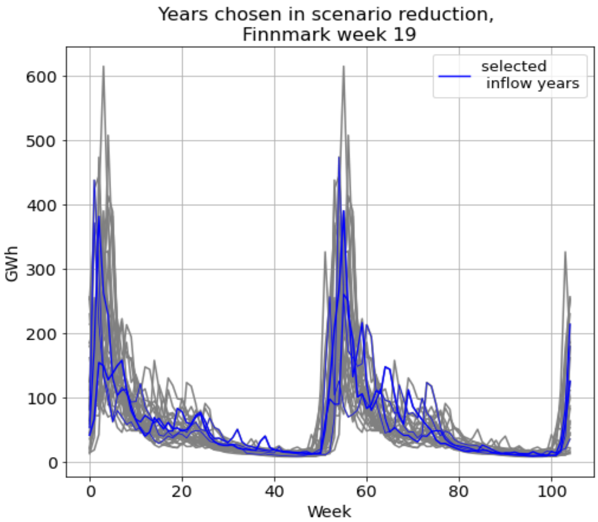

Figure 56: Inflow for the scenarios chosen in week 19 for Finnmark for A-4

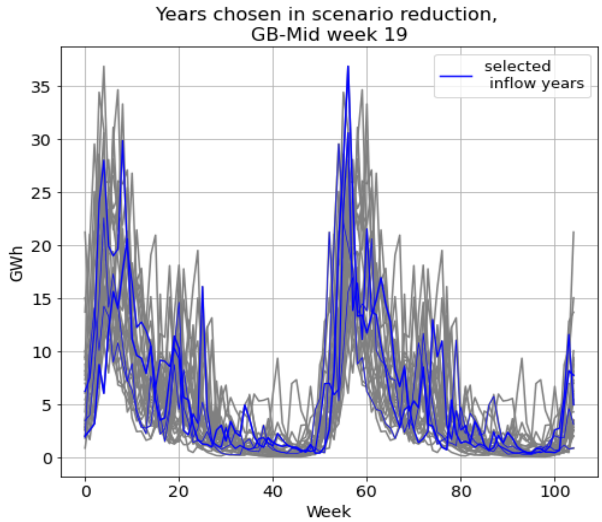

Figure 57: Inflow for the scenarios chosen in week 19 for GB-Mid for A-4

A-5

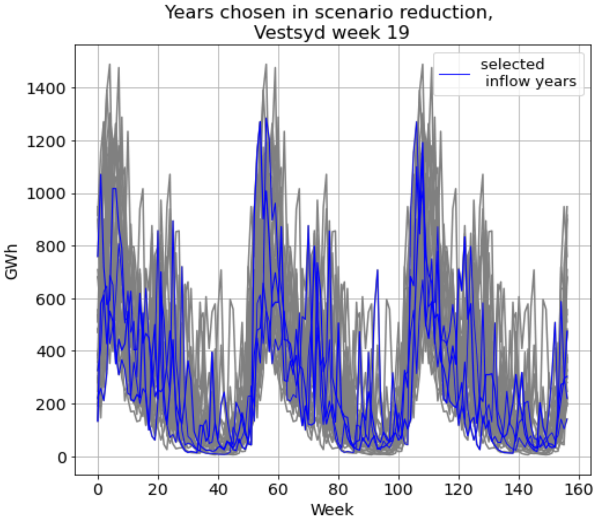

Figure 58: Inflow for the scenarios chosen in week 19 for Vestsyd for A-5

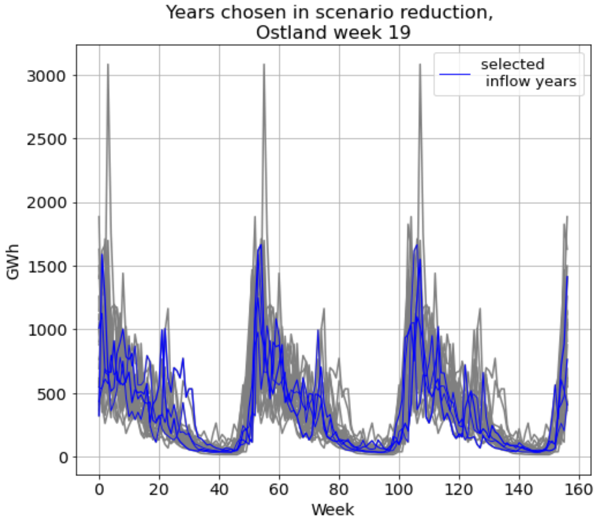

Figure 59: Inflow for the scenarios chosen in week 19 for Ostland for A-5

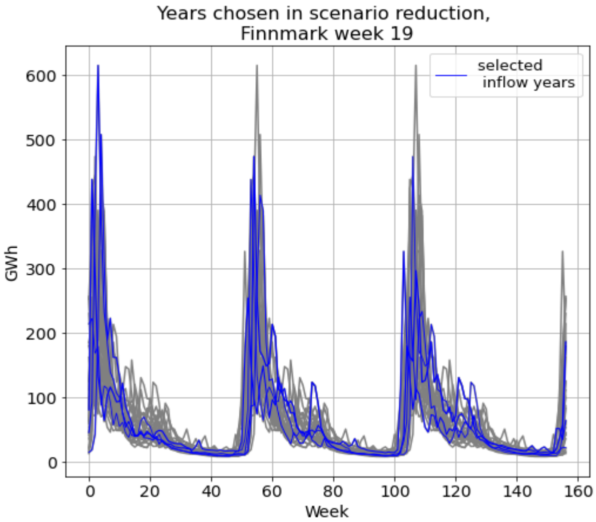

Figure 60: Inflow for the scenarios chosen in week 19 for Finnmark for A-5

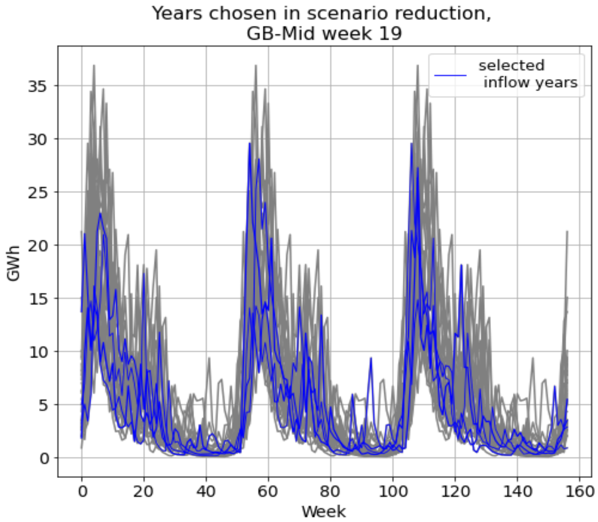

Figure 61: Inflow for the scenarios chosen in week 19 for GB-Mid for A-5

A-6

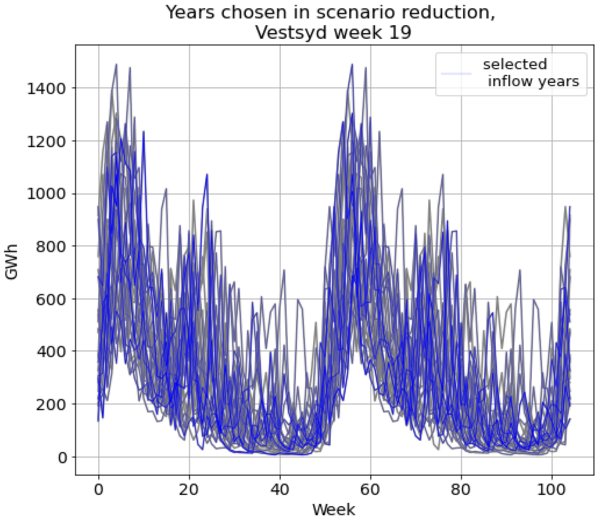

Figure 62: Inflow for the scenarios chosen in week 19 for Vestsyd for A-6

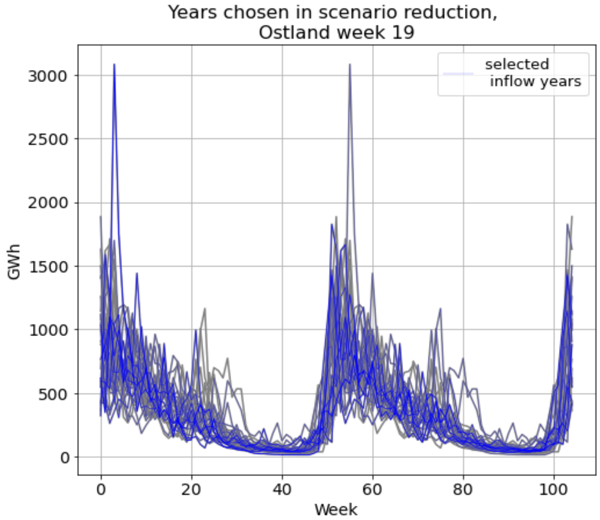

Figure 63: Inflow for the scenarios chosen in week 19 for Ostland for A-6

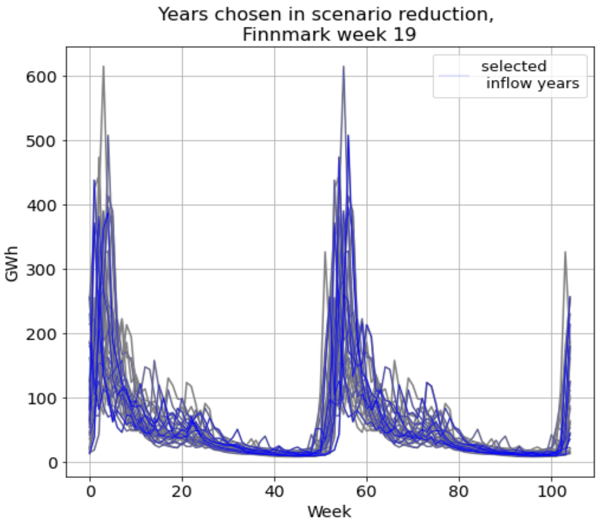

Figure 64: Inflow for the scenarios chosen in week 19 for Finnmark for A-6

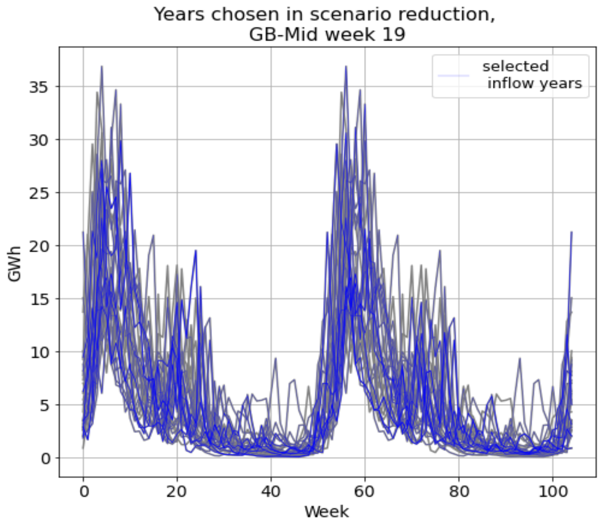

Figure 65: Inflow for the scenarios chosen in week 19 for GB-Mid for A-6

The chosen inflow scenarios in week 19 for Vestsyd, Ostland, Finnmark, and GB-Mid for the different parametrizations A-1 to A-6 are shown in the figures 42-65. In the figures for A-1, 42 - 45, one can observe that the four chosen inflow years represent mean values. The selected curves are in the middle to lower part of all the inflow curves. Some information about the wet years is lost. As one can see, there is a lack of curves with the highest peaks. In addition, the inflow years selected have high probabilities as they are bold. One can see the same observation for A-4 and

A-5 in 54-61. On the other hand, the chosen years are different for A-4 and A-5. From the graphs, the wet years seem to be better represented for parts of the curve than in A-1.

For A-2 in 46-49, 10 scenarios are selected. In comparison to A-1, each instance has a lower probability. Selecting more scenarios in the scenario fan gives a better possibility to give a sufficient representation of different weather years. More years with a high inflow are included in the selection of scenarios. On the other hand, the highest inflow years are excluded. Looking at a parametrization with 20 scenarios 50-53, A-3, one can see that many scenarios are covered. The dataset used in this thesis includes 30 different weather years, and with 20 scenarios, the range of inflow years is well represented. This is observed with a mixture of years with high and low probabilities.

To combine a long time horizon and many scenarios, A-6 was created, seen in 62-57. For this case, 20 scenarios for a time horizon of 2 years are chosen. One can see a variation of the weather years represented, both with high and low probability.

From these results, it appears that FanSi selects average inflow years when a few scenarios are specified. When increasing the number of scenarios to 10, there is a better representation of different types of inflow years. With 20 scenarios in the fan, it gives the possibility to have a good mixture of wet and dry scenarios with different probabilities.

Looking at the social welfare in table 3, which is further discussed in the next part, an increase in the number of scenarios always leads to an increase in social welfare, showing how a better representation of uncertainty through weather years is important.

8.2 Social welfare

In table 8, the average total social welfare for the different parametrizations for scenarios A-D is presented, which has the same setup as the case matrix found in table 3. The table presents the value for the base case for each scenario. Both the value and the difference relative to the base case are shown for the corresponding parametrizations. For A-2, the upper value is the social welfare of this case, while the lower value represents the difference between A-1 and A-2. The same for B-1 and B-2 and the rest of the cases.

Table 8: Average social welfare for the different parametrizations

	Social welfare [Mkr]					
	A-1	**A-2**	**A-3**	**A-4**	**A-5**	**A-6**
	64617533,45	64617755,36 +**221,91**	64617902,28 +**368,83**	64617273,66 **-259,79**	64616958,03 **-575,42**	64617539,13 +**5,68**
	B-1	**B-2**	**B-3**	**B-4**	**B-5**	
Total	64240646,29	64242733,65 +**2087,36**	64243882,61 +**3236,32**	64241482,80 +**836,51**	64241181,85 +**535,56**	
	C-UV-1	**C-UV-2**	**C-UV-3**	**C-UV-4**	**C-UV-5**	
	64609729,16	64609999,36 +**270,2**	64610203,19 +**474,03**	64609661,22 **-67,94**	64609296,74 **-432,42**	
	C-MV-1	**C-MV-2**	**C-MV-3**	**C-MV-4**	**C-MV-5**	
	64609980,60	64610223,95 +**243,35**	64610347,32 +**366,72**	64609633,75 **-346,85**	64609222,50 **-758,1**	
	D-1	**D-2**	**D-3**	**D-4**	**D-5**	
	64620567,11	64620743,66 +**176,55**	64620886,94 +**319,83**	64620290,26 **-276,85**	64619981,41 **-585,7**	

As stated in part 3.1, social welfare is a term that describes the collected effect on society in a simple manner. The total social welfare for all cases can be seen in table 8. Looking at the original dataset A, one can observe that the increase in social welfare correlates to an increase in the number of scenarios seen for A-2 and A-3. For the parametrizations A-4 and A-5, the length of the scenario fan is increased, but the number of scenarios is kept at 4. These cases lead to lower social welfare compared to the base case A-1. Case A-6 has 20 scenarios and a time horizon of two years. The result of this is a marginal increase in the total social welfare for A-6 relative to the base case. From this, one can conclude that it is vital to use a sufficient number of scenarios when applying a long time horizon. Using 4 scenarios decreases social welfare, but with 20 scenarios, the social welfare slightly increases. On the other hand, one does not investigate if 10 scenarios with a long time horizon would be sufficient.

The same observations can be done for C-UV, C-MV, and D. The social welfare increases for the parametrizations -2 and -3 and decreases for -4 and -5. For B, with high fuel prices, the increase of social welfare for -2 and -3 compared to the base dataset are higher than the other scenarios. When changes are made to fuel prices, the results show the importance of a better representation of uncertainty. Unlike the other cases, B-4 and B-5 experience increased social welfare compared to the base case. From this, one can conclude that a long time horizon is also valuable when using a few scenarios for a scenario like B.

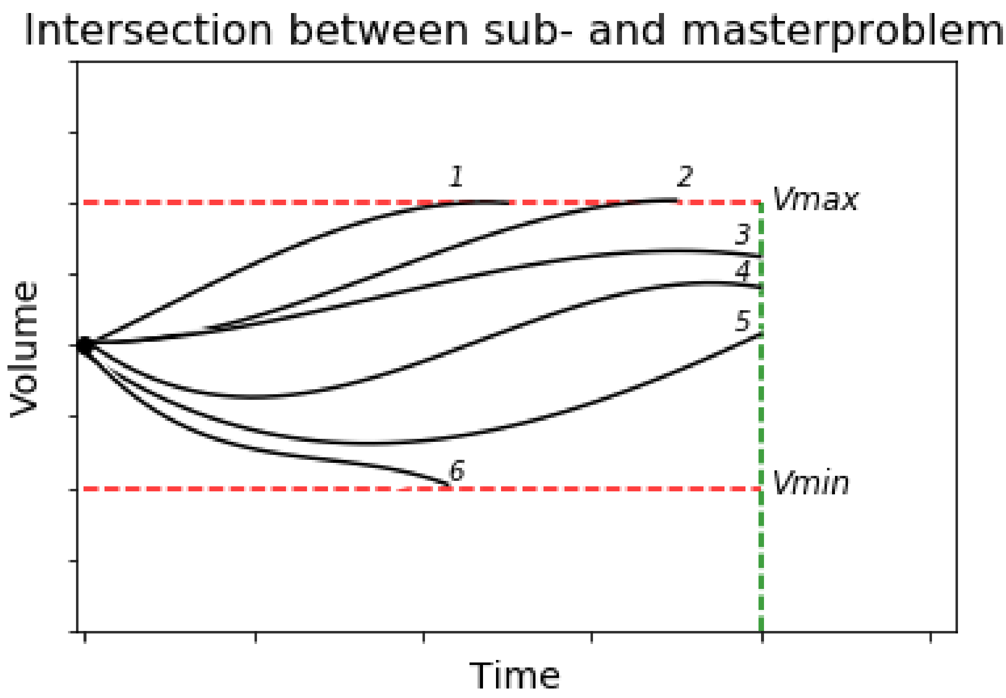

Figure 66: FanSi's representation of selecting water values using different possible reservoir scenarios

During the duration of this master's thesis, one discovered a weakness when running scenarios with weekly time-resolution in FanSi. When using a long time horizon, the water values seem to be set too low, resulting in lower social welfare than expected. To explain what happens, figure 66 is presented. The figure is largely inspired by SINTEF Energy's work on FanSi's parametrization. The figure presents 6 different paths the reservoir curve can take based on the weather year and the exploitation of water. The scenario curve is used as a strategy in the sub-problem to give values to the master problem. The point on the y–axis represents the intersection between the master- and the sub-problem, showing the information which is reflected in the master problem. For a reservoir, figure 66 illustrates the development of the reservoir level for different scenarios given by the inflow years. For scenarios where the reservoir level peaks, the end water value will be equal to zero. Following the curves 1 and 2, one can see that it leads to flooding, giving 0 as the end water value. For 3, 4, and 5, the end-value will be set from the EMPS model, while line 6 leads to rationing.

For the last curve, number 6, the problem occurs. When the model sees a possibility for rationing, the alternative will, in some areas, be to purchase power in the market. When the model uses information about imports and purchases from other resources, the model utilizes the power price in the market. The market price is endogenous to the model, meaning that it is computed within the model. For these simulations, the time resolution is set to one week, leading to lower area prices than if the resolution was 3 hours, as it is in the master problem. Therefore, there will be an underestimation of the pricing of a rationing situation, and the master problem solution will not sense the real danger of rationing occurring. One can spot the problem in this dataset for France, which is modeled with one reservoir. The same pattern is not observed in the Norwegian areas as hydropower is modeled differently here. The weakness described here can help explain why the social welfare surplus will decrease with an increased scenario length.

One can conclude that the optimal parameterization will differ based on the scenario. For the cases presented here, the results are similar between the parametrizations for A, C, and D, while B stands out. As a general result, enough scenarios in the scenario fan, which adds a better representation of uncertainty in the model, will, in all cases, give an increase in social welfare. Other factors will need to be analyzed to say something about how important a long time horizon is.

8.3 Area prices

In part 8.3.1, duration curves for area prices for the parametrizations -1, -2, and -3 are presented for the area Ostland for scenarios A and B. While in part 8.3.2, the duration curves for the same area is presented for the parametrizations -1, -4, -5, and -6 (for A). The results found were quite similar for the different areas in Norway. Therefore, the results for the other areas can be found in Appendix K, 13.11. Different parametrizations are presented in separate curves to isolate the effect of more scenarios and a longer time horizon. Changing parameters in the control input file in FanSi will affect the water value calculation. As Norway's energy supply mainly consists of hydropower, the parametrizations will influence the Norwegian area prices. Part 8.3.3 shows duration curves for Tysk-Nord and GB-Mid to show the effect on other European areas.

8.3.1 Increased number of scenarios

A

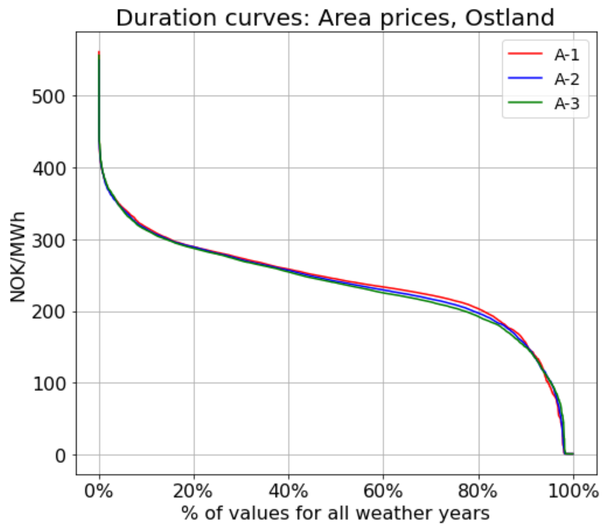

Figure 67: Duration curves for the area prices for Ostland when increasing the number of scenarios for A

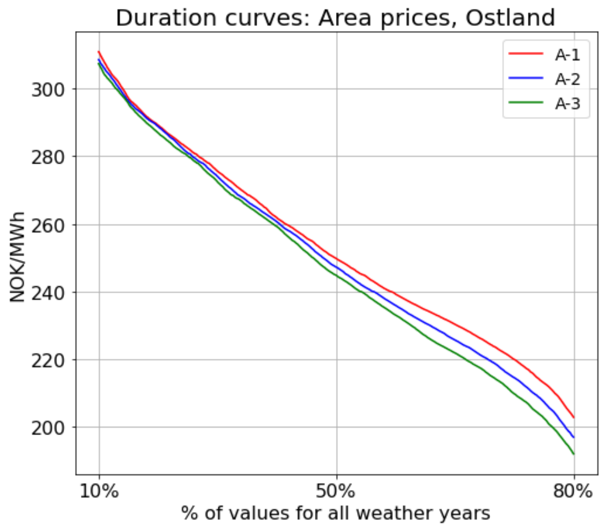

Figure 68: Detailed duration curves for the area prices for Ostland when increasing the number of scenarios for A

B

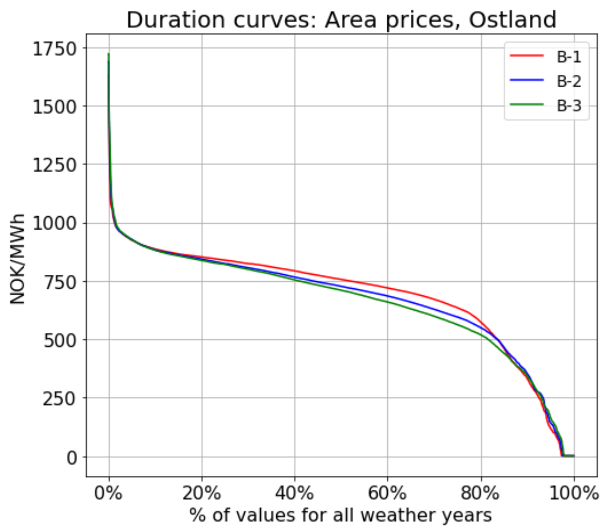

Figure 69: Duration curves for the area prices for Ostland when increasing the number of scenarios for B

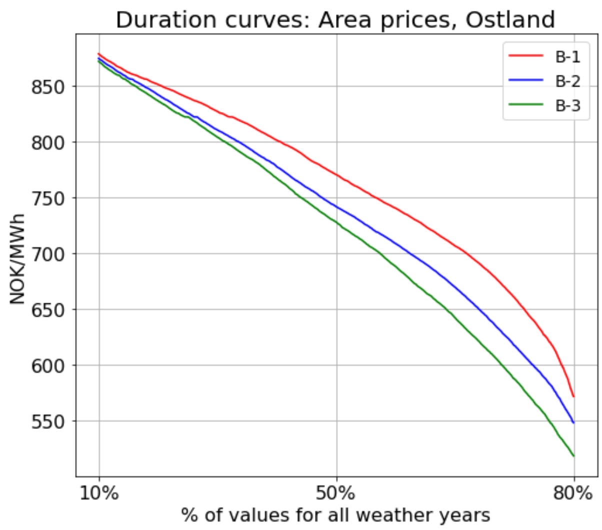

Figure 70: Detailed duration curves for the area prices for Ostland when increasing the number of scenarios for B

8.3.2 Increased scenario-length

A

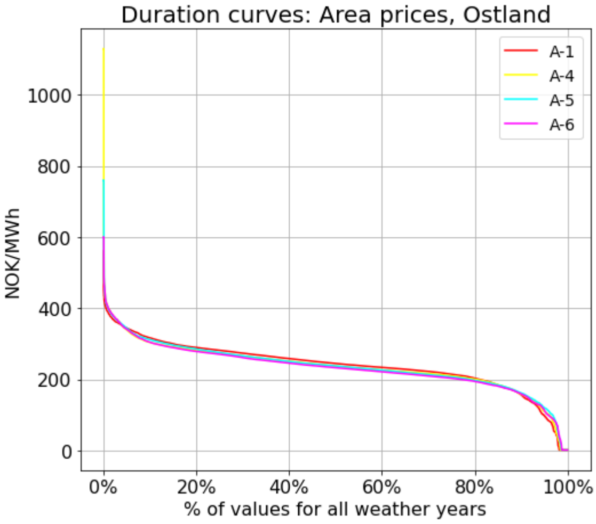

Figure 71: Duration curves for the area prices for Ostland when increasing the time horizon for A

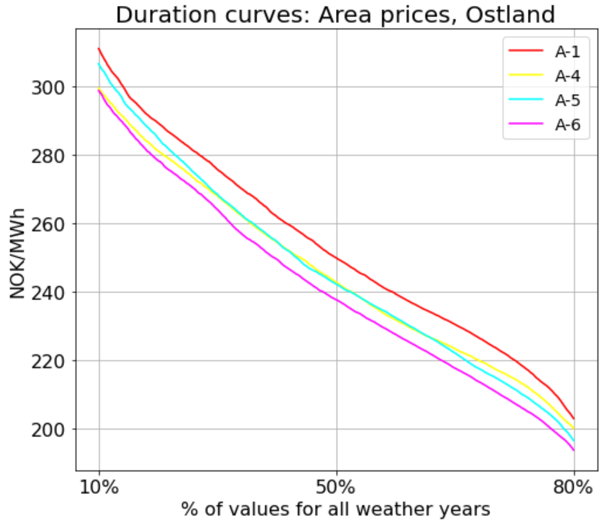

Figure 72: Detailed duration curves for the area prices for Ostland when increasing the time horizon for A

B

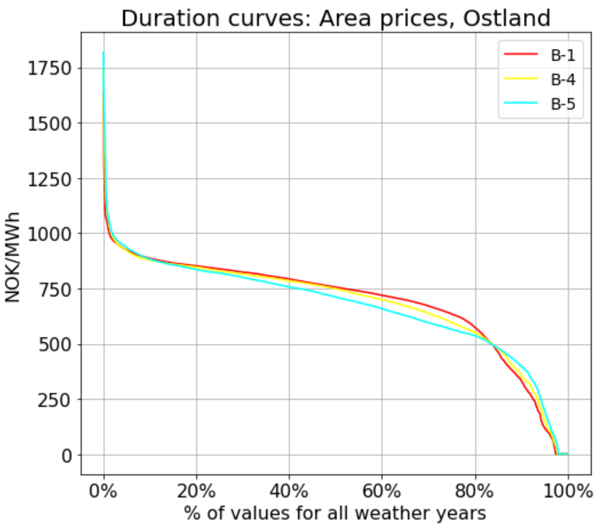

Figure 73: Duration curves for the area prices for Ostland when increasing the time horizon for B

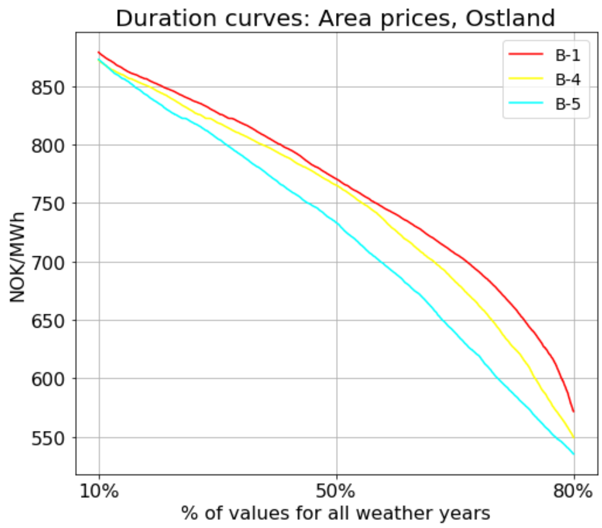

Figure 74: Detailed duration curves for the area prices for Ostland when increasing the time horizon for B

8.3.3 European areas

Tysk-Nord

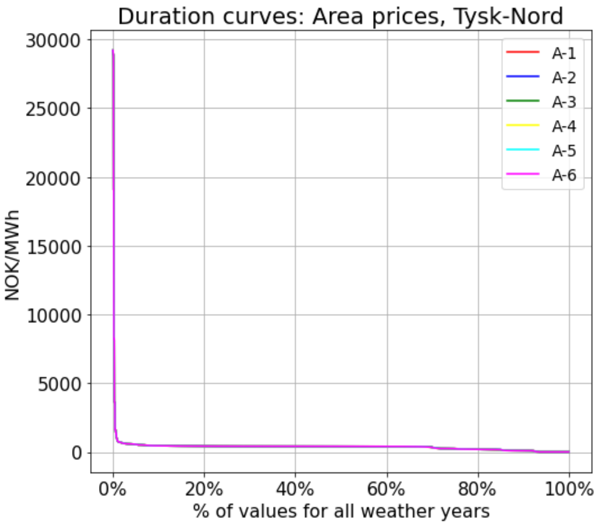

Figure 75: Duration curves for the area prices for Tysk-Nord

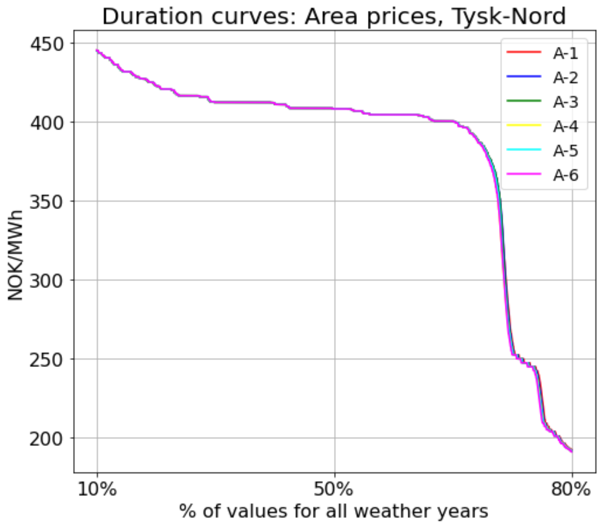

Figure 76: Detailed duration curves for the area prices for Tysk-Nord

GB-Mid

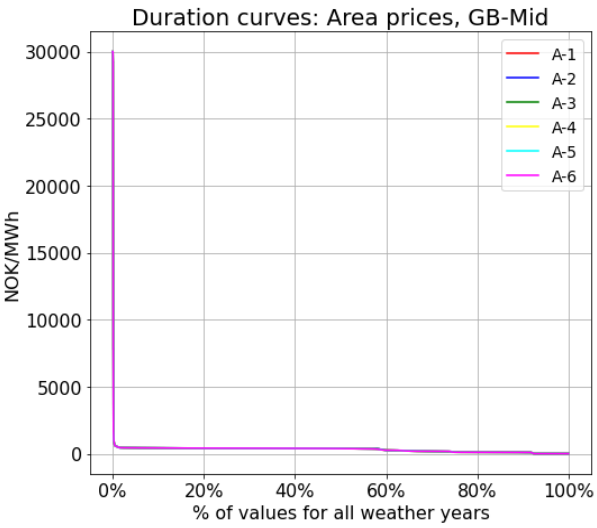

Figure 77: Duration curves for the area prices for GB-Mid

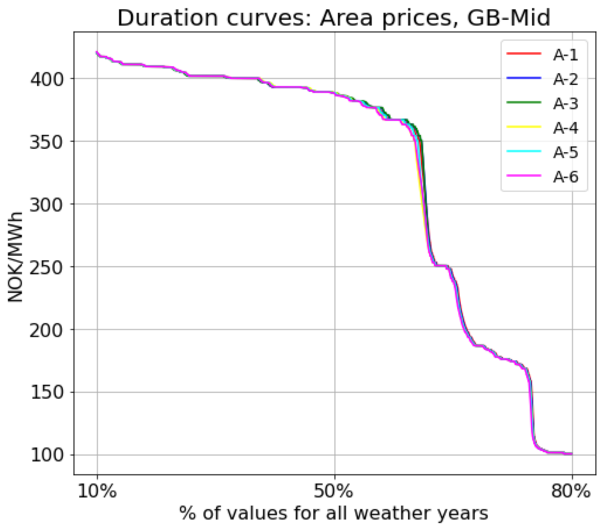

Figure 78: Detailed duration curves for the area prices for GB-Mid

The duration curves for increasing the number of scenarios are presented in section 8.3.1. The general observation from these is that increasing the number of scenarios reduces the area prices. Increasing the fuel prices gives more significant differences between the parametrizations. An observation is that the distance between maximum and minimum has increased for scenario B. Therefore, better utilization of water will be more visible in this case. As the difference between 10 and 20 scenarios for large parts of the duration curve is relatively small, one can conclude that 10 scenarios seem to give an adequate amount of information to the simulation. In most cases, it is not necessary with 20.

In part 8.3.2, the duration curves for area prices for the cases with increased scenario-length are presented. From the curves for dataset A, one can observe that A-6 gives the lowest prices. The differences are pretty slight when looking at the curves for -1, -4, and -5. One can observe that the Norwegian area prices are lower for A-4 and A-5 compared to the base case. For B, one can observe that for a large part of the curve, -5 gives the lowest area prices and -1 the highest. This corresponds to -4 and -5, giving higher social welfare than -1 for this case. The differences between the parametrizations are also for a longer time-horizon larger for B than for A. When looking at the curves for GB-Mid and Tysk-Nord, which can be seen in the figures 75-78, there seem to be even smaller differences between the parametrizations. In some sense, both Germany and Great Britain will be affected by the price changes in Norway through price signals due to the subsea cables. The effect will be reduced as a cause of external cables and will not give a significant difference in the graphs.

To summarize, both an increase in the number of scenarios and the scenario length decrease Norwegian area prices, showing how a long time horizon also gives value to the simulations. It can be observed that the value of more scenarios and a longer time horizon is more significant for scenario B, corresponding to the more considerable difference in social welfare. It substantiates that an increase in fuel prices increases the importance of information to obtain a better simulated results for a dataset.

8.4 Reservoir level

In this part, the 0-, 20-, 50-, 80-, and 100-percentile are depicted for the reservoir levels for Blåsjø and Frøystøl for all scenarios A-D. The percentiles are based on values for all weather years in the dataset. There is one plot where the parametrizations -1 and -3 are compared and one plot where the parametrizations -1 and -5 are plotted. This representation is selected to simplify the plots. In addition, one has selected these plots to analyze the effect of the chosen parametrizations further. As the same changes, to a certain degree, are expected of -2 and -3, this section only presents one of them. The same explanation is why only -5 and not -4 is presented.

8.4.1 Blåsjø

Increased number of scenarios

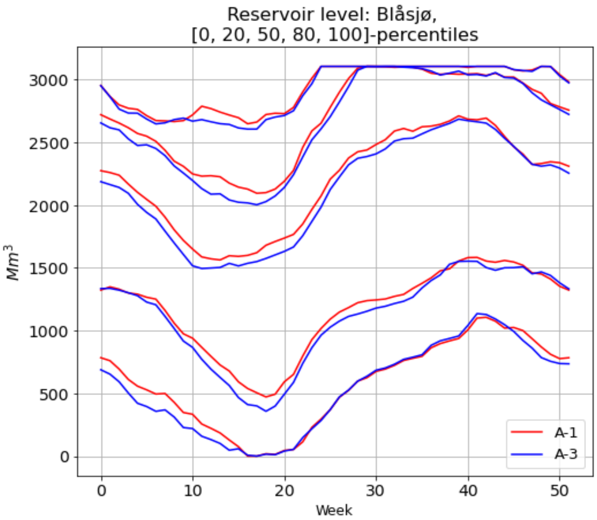

Figure 79: Percentiles for the reservoir level for Blåsjø when increasing the number of scenarios for A

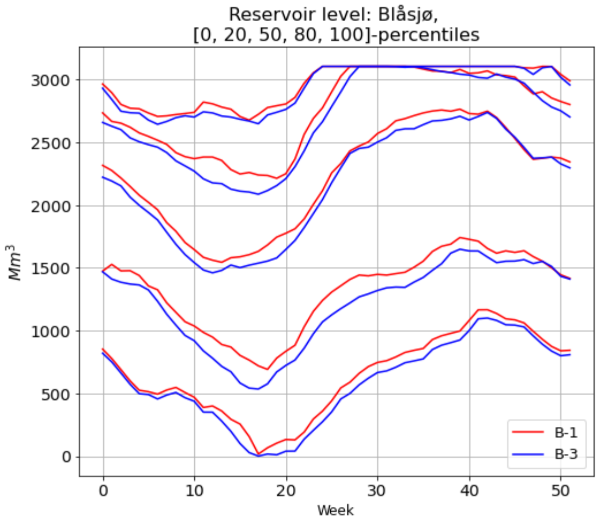

Figure 80: Percentiles for the reservoir level for Blåsjø when increasing the number of scenarios for B

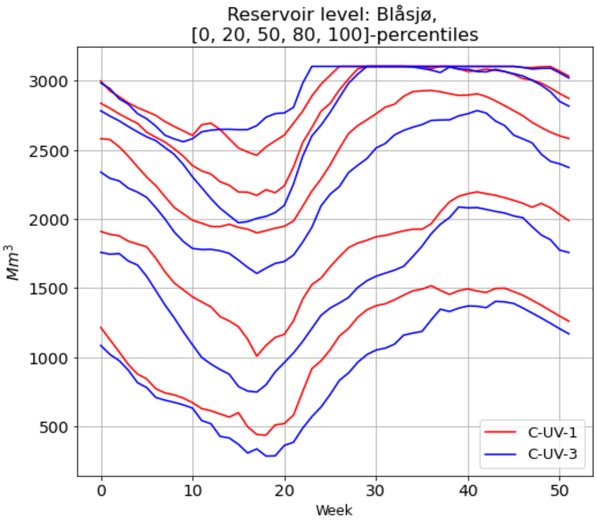

Figure 81: Percentiles for the reservoir level for Blåsjø when increasing the number of scenarios for C-UV

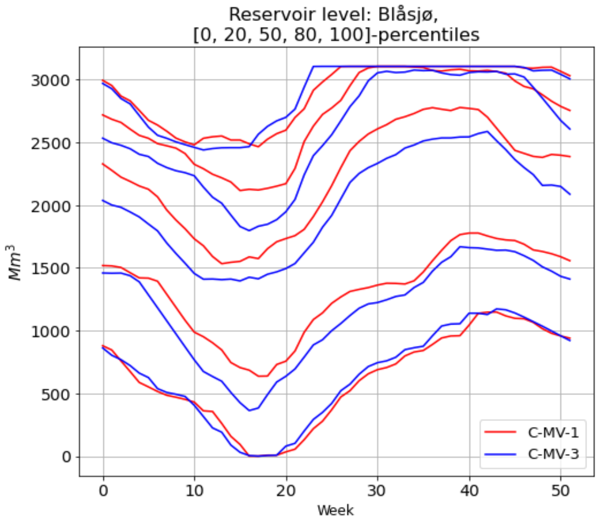

Figure 82: Percentiles for the reservoir level for Blåsjø when increasing the number of scenarios for C-MV

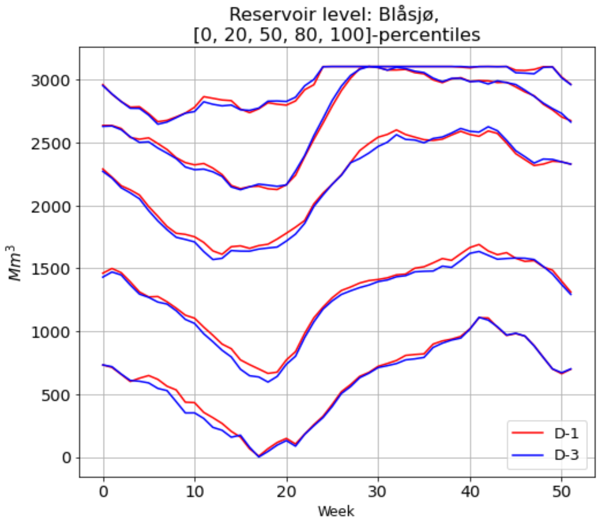

Figure 83: Percentiles for the reservoir level for Blåsjø when increasing the number of scenarios for D

Increased scenario-length

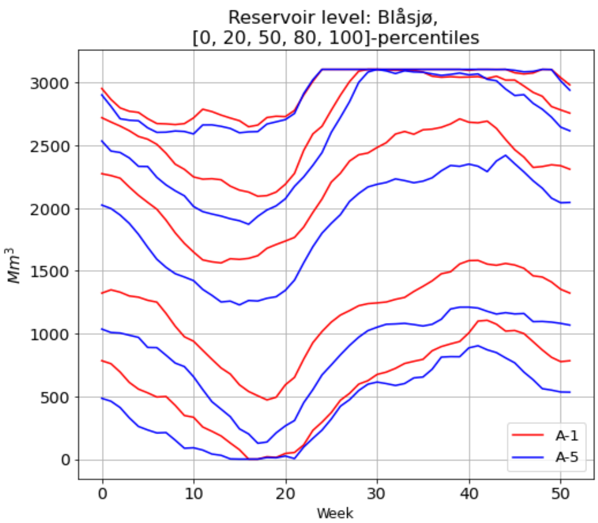

Figure 84: Percentiles for the reservoir level for Blåsjø when increasing the time horizon for A

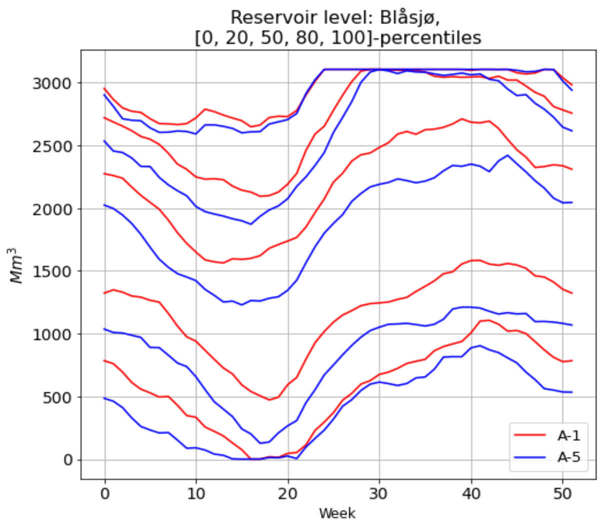

Figure 85: Percentiles for the reservoir level for Blåsjø when increasing the time horizon for B

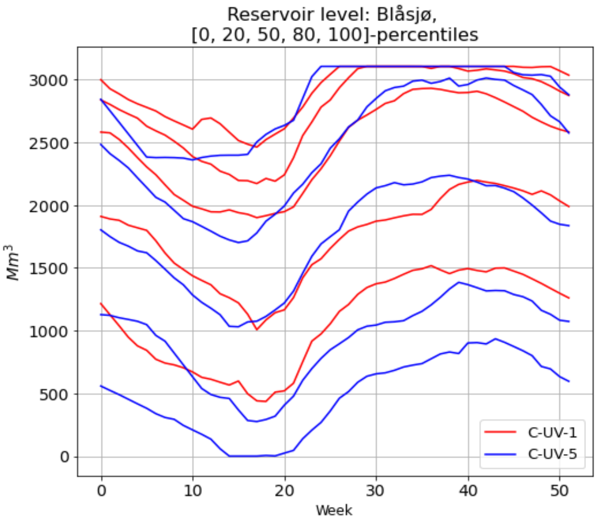

Figure 86: Percentiles for the reservoir level for Blåsjø when increasing the time horizon for C-UV

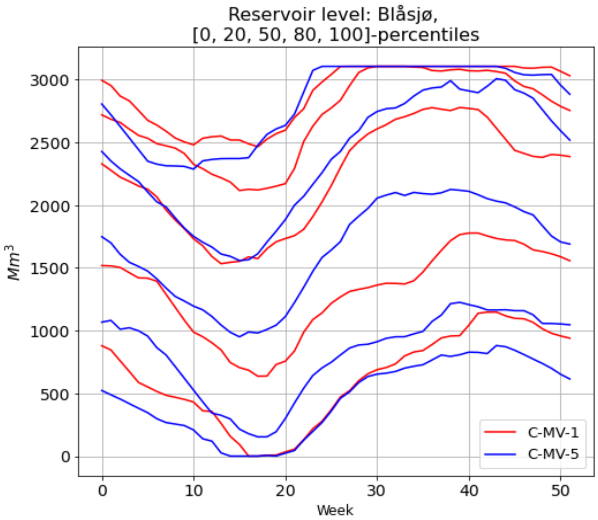

Figure 87: Percentiles for the reservoir level for Blåsjø when increasing the time horizon for C-MV

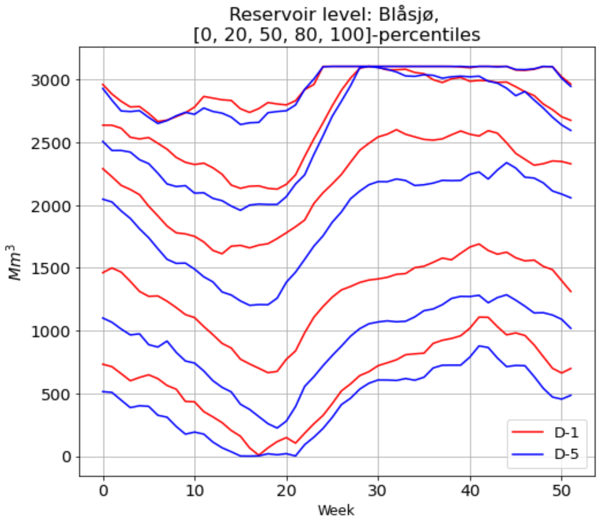

Figure 88: Percentiles for the reservoir level for Blåsjø when increasing the time horizon for D

8.4.2 Frøystøl

Increased number of scenarios

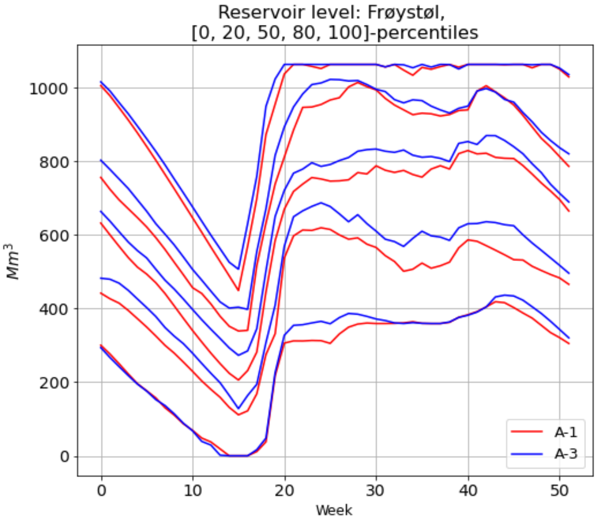

Figure 89: Percentiles for the reservoir level for Frøystøl when increasing the number of scenarios for A

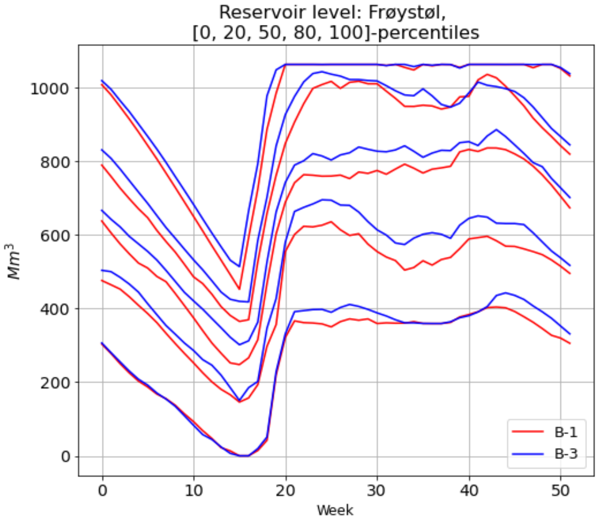

Figure 90: Percentiles for the reservoir level for Frøystøl when increasing the number of scenarios for B

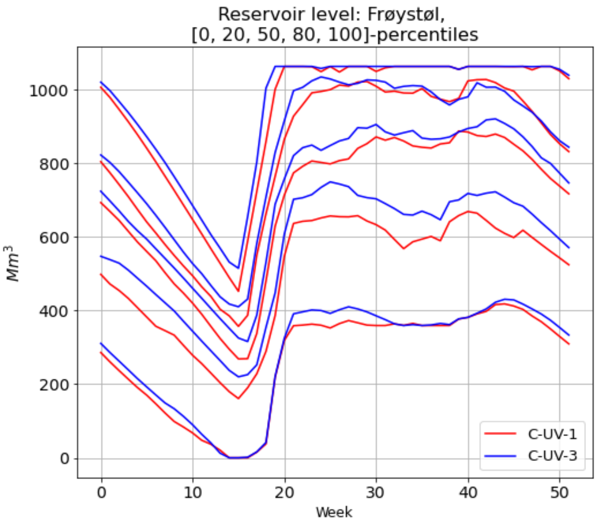

Figure 91: Percentiles for the reservoir level for Frøystøl when increasing the number of scenarios for C-UV

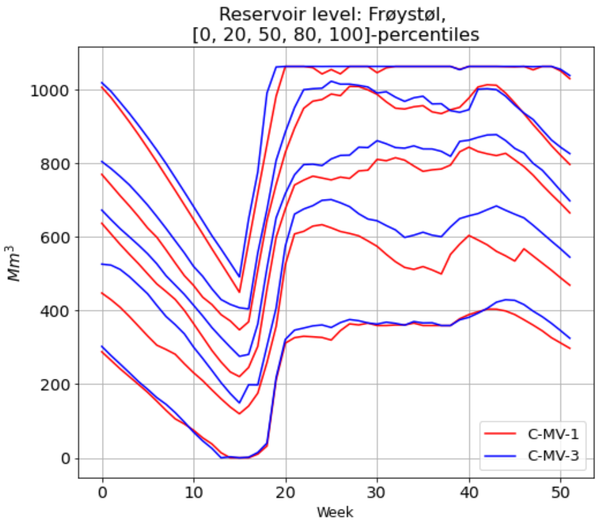

Figure 92: Percentiles for the reservoir level for Frøystøl when increasing the number of scenarios for C-MV

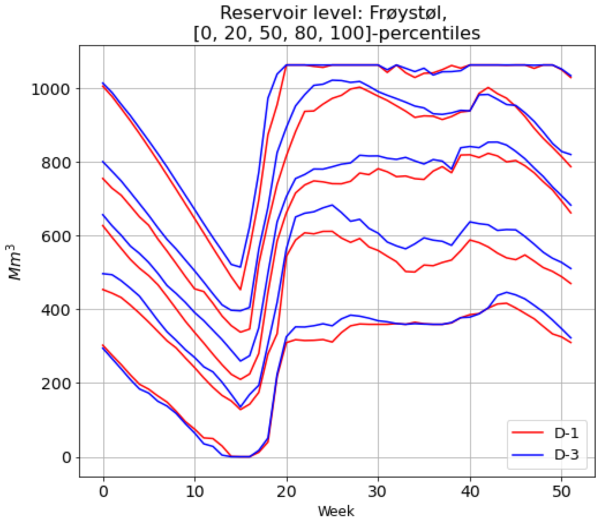

Figure 93: Percentiles for the reservoir level for Frøystøl when increasing the number of scenarios for D

Increased scenario-length

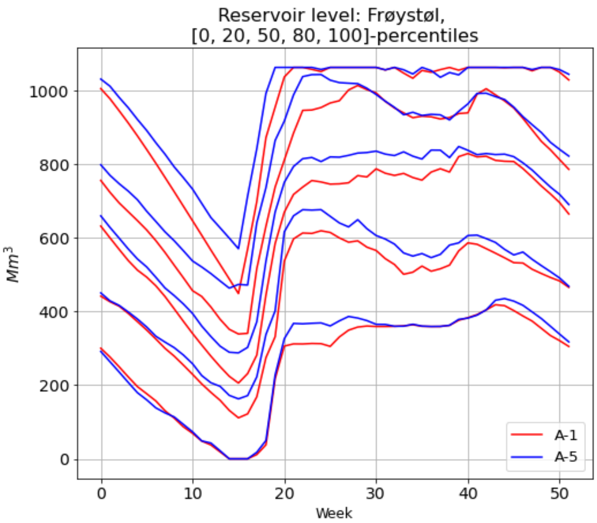

Figure 94: Percentiles for the reservoir level for Frøystøl when increasing the time horizon for A

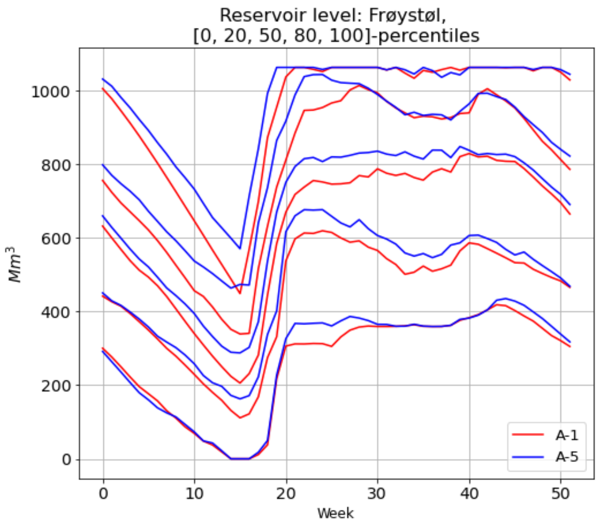

Figure 95: Percentiles for the reservoir level for Frøystøl when increasing the time horizon for B

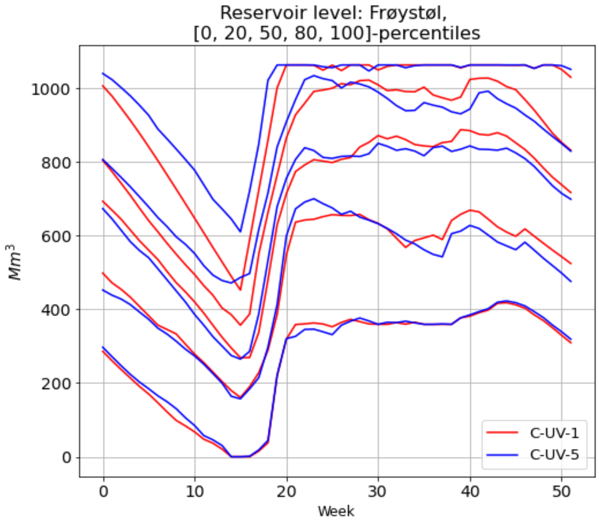

Figure 96: Percentiles for the reservoir level for Frøystøl when increasing the time horizon for C-UV

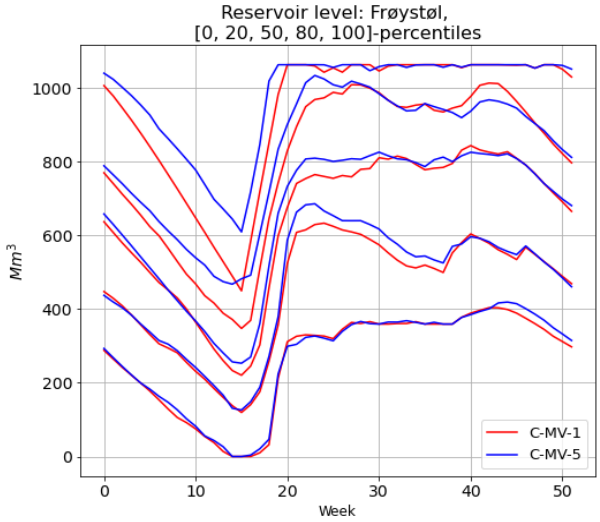

Figure 97: Percentiles for the reservoir level for Frøystøl when increasing the time horizon for C-MV

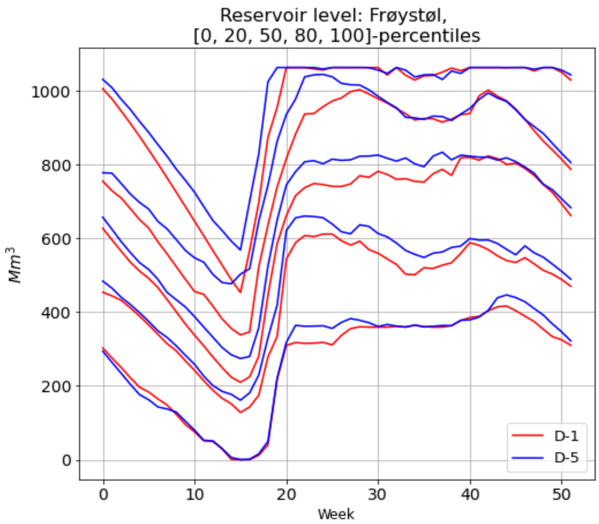

Figure 98: Percentiles for the reservoir level for Frøystøl when increasing the time horizon for D

The reservoir curves for Blåsjø and Frøystøl with percentiles are presented. One has also investigated smaller reservoirs, but the results are not a part of the discussion due to minor or insignificant differences. These plots can be found in Appendix L, 13.12. The slight differences for these reservoirs substantiate how a change in water values has an insignificant effect on smaller reservoirs.

The curves for Blåsjø are presented in part 8.4.1. A general tendency is that parametrization -3 gives lower reservoir levels for all percentiles than the -1 parametrization. The scenario that presents the smallest difference between the parametrizations is D. The amount of spillage is the same for all curves. It does not change for different parametrizations, while the amount of rationing differs. For dataset A, the time the 0-percentile is at 0 - level is equal for the parametrizations. In scenario B, the 0-percentile for B-3 is longer at 0 - level compared to B-1. When looking at the curves for C-UV and C-MV, the differences between -1 and -3 are bigger compared to both A, B, and D.

For the parametrizations looking at the effect of an increased scenario length, differences between -1 and -5 are bigger than for -1 and -3. A general observation is that the reservoir uses more time at 0-level with an increase in the scenario length. The amount of spillage seems to be unaffected by the parametrizations. The simulations are run in series mode, and therefore the start points of the reservoir curves are different. For C-MV-1, percentiles 20-80 are much higher than for C-MV-5, showing better water utilization when increasing the time horizon.

For both C-UV and C-MV, the differences between -1 and -3 are higher than in the other datasets. One can observe the same for -1 and -5. From this, one can conclude that the reservoir levels seem to be more sensitive to the parametrizations selected when the subsea cables are removed.

Looking at Frøystøl in part 8.4.2, the 20-80-percentiles for -3 and -5 are generally higher than the ones for -1. Both parameter changes do not lead to differences in the parametrizations in terms of spillage and time when the reservoir is empty.

Both an increase in the number of scenarios and scenario length seem to give a better water utilization in Blåsjø, with lower reservoir levels, even though the amount of spillage is nearly unchanged. For Frøystøl, the amount of spillage and rationing is unaffected, which supports how a change in water values has minor effects on smaller reservoirs.

8.5 Model run time

The model run time for the different parametrizations is presented in table 9, for more in detail information about start and end time, see Appendix M, 13.13.

Table 9: Model run time for the different parametrizations

Model run time					
A-1	**A-2**	**A-3**	**A-4**	**A-5**	**A-6**
40h, 19min	47h, 51min	57h, 25min	107h, 31min	185h, 40min	156h, 37min
B-1	**B-2**	**B-3**	**B-4**	**B-5**	
43h, 32min	53h, 55min	72h, 1min	128h, 56min	231h, 24min	
C-UV-1	**C-UV-2**	**C-UV-3**	**C-UV-4**	**C-UV-5**	
41h	49h, 30min	70h, 39min	117h, 53min	206h, 44min	
C-MV-1	**C-MV-2**	**C-MV-3**	**C-MV-4**	**C-MV-5**	
57h, 18min	69h, 8min	59h	113h, 50min	225h, 57min	
D-1	**D-2**	**D-3**	**D-4**	**D-5**	
40h, 47min	51h, 6min	52h, 33min	123h, 24min	200h, 12min	

In table 9, the run times for the different parametrizations can be found. The -1 parametrizations take the shortest time, and the time increases for -1 to -5 and -6. One can conclude that more scenarios will increase the run time while increasing the scenario length increases the run time even more. When increasing the number of scenarios, parallel processing does not significantly affect the run time. The simulation use n + 1 processors, where n equals the number of scenarios.

On the other hand, even if the run time is not significantly affected when running more scenarios, it requires more of the capacity of the CPU. There will be an increase in computational time when the capacity is maximized when running multiple simulations. Therefore, the shortest times for each parametrization type represent the actual computational time needed without interference. In this thesis, multiple cases were run at the same time. As a result, some of the longest runs result from the computer not having the capacity to calculate as fast.

The results show that the -1 parametrizations take between 37 to 47 hours, except C-MV-1, which used 57 hours. The computational time is affected if other simulations are run simultaneously. When C-MV-1 was running, A-6 was as well. A-6 uses 20 scenarios, meaning 26 processors were used at once. This resulted in a longer computational time for C-MV-1 compared to the rest of -1 parametrizations. For the -2 parametrizations, the run time varies between 43 to 52 hours, again with C-MV-2 as an exception, which used 69 hours. One can see that the increase in scenarios and processors needed adds some time to the model run time. C-MV-2 was run simultaneously as B-3, meaning there in total were 32 processors used, which led to the longer computational time. The -3 parametrizations took around 52 to 72 hours.

The increase in the time horizon seems to have a more significant impact on the computational time than increasing the number of scenarios. On the other hand, less CPU capacity is utilized for these cases, giving the possibility to run more simulations at once without affecting the computational time. The -4 parametrizations used 107 to 123 hours, while the -5 parametrizations range from 185 to 231 hours.

The previous results between different parametrizations show a higher gain from increasing the number of scenarios compared with increasing the number of weeks. The same conclusion can be drawn for the results in this part, as the increase in computation time is much longer for an increase in time horizon than an increase in the number of scenarios.

8.6 Main points

This part of the thesis concludes the main points from the discussion of the optimal parametrizations for the different scenarios.

The main points which can be taken from this are:

- The scenario reduction algorithm is tested using 4, 10, and 20 scenarios. Using 4 scenarios leads the chosen scenarios to represent curves in the middle to lower part of the inflow curves. For 10 scenarios, a better representation of dry- and wet years are obtained, while the belonging probabilities to the weather years are smaller than when using 4 scenarios. When using 20 scenarios, one gets a good representation of different inflow years and scenarios with both high and low probability. The conclusion is that the algorithm gives a decent representation of different weather years, missing some of the peak inflow curves.

- Having a sufficient number of scenarios in the scenario fan is essential when choosing a parametrization. All simulations get better social welfare for the total system and lower area prices in Norway when increasing the number of scenarios. The results conclude that 10 scenarios will be sufficient to achieve a satisfactory result in most instances. 20 scenarios will give better simulation results, but 10 should be sufficient in most cases. In this thesis, a simulation using all 30 scenarios is not tested, which would be the ideal benchmark.

- When increasing the length of the scenario, the general result is that both the social welfare and area prices decrease. The parametrization in A-6, where the number of scenarios in the scenario fan is increased together with the scenario length, increases social welfare. Due to the weakness found in the calculation for a longer time horizon, one can not conclude if there is added value in using a time horizon of two to three years from the social welfare results. Thus, looking at the area prices, a decrease is observed for a longer time horizon, substantiating how it will benefit the simulation results.

- The optimal parametrization will differ dependent on the system configuration

(Scenarios A-D). For the different configurations run in this thesis, the result for the different parametrizations is quite similar for all configurations except scenario B with high fuel prices. A good representation of uncertainty and a long time horizon are essential for high fuel prices. Nonetheless, a good representation of uncertainty is the most crucial factor for the rest.

- The computational time for the simulations increases with both the number of scenarios and the time horizon. The time increases more for a longer horizon than an increase in the number of scenarios. Looking in context with social welfare and area prices, this validates the claim that one should prioritize more scenarios rather than increasing the length of the scenario. The impact of more scenarios is more significant than the impact of a longer scenario horizon.

Together, these results show how enough scenarios in the scenario fan are vital for getting adequate results and should be prioritized when choosing a parametrization. Due to the weakness in the model, it is hard to draw conclusions about a long time horizon. The observations are that the area prices decrease, and higher utilization of the reservoirs. Therefore an increase in weeks should also be considered. From the results and discussion, one can conclude that 10 scenarios are a sufficient amount in simulations of similar datasets. The research question for this part is if a parametrization is superior in terms of the scenarios or if it will vary. The results and analyses done in this section show that increasing the number of scenarios is superior for all the datasets used. The parametrization giving the highest social welfare, lowest area prices, and a reasonable run time in the simulations are when the number of scenarios is 20 and the number of weeks is 52.

9 Cases - Norway in different situations

Three different datasets and three different scenarios are analyzed to investigate how Norway will be affected in a scarcity and in two surplus situations. The first dataset is the base dataset used in the previous part. The second represents Norway in a scarcity situation and the third represents Norway in a large surplus situation. For all three datasets, there will be run different scenarios: one where the subsea cables connected to Norway are removed (C), a scenario where the capacity to Great Britain is scaled up (D), and a scenario with a high rationing price (E). The results and discussion about the different scenarios are presented in part 10. There will also be run two different parametrizations on these scenarios, which corresponds to case -1 and -2 as described in part 6. The case matrix for this part can be found at the bottom of the section, in part 9.5.

9.1 Dataset F: Base

Dataset F represents the same dataset as in A from the previous part. This dataset represents a scenario for a part of the European system in 2030. Norway is in a surplus situation where the demand lies at 137 TWh and the production at 172 TWh, giving a surplus of 35 TWh. The same results from running A-1, A-2, C-MV-1, C-MV-2, D-1, and D-2 in the former part of the thesis are used to investigate the differences between the datasets. For this section these cases are respectively F-1, F-2, FC-1, FC-2, FD-1, and FD-2. There is also run a scenario E-1 and E-2, which is the scenario with high rationing price with the two different parametrizations. A description of this scenario is found below.

9.2 Dataset G: Norway in a scarcity situation

There is expected an increase in the Norwegian demand due to electrification projects in the coming years. In Statnett's analysis, [5], it is expected that Norway will have a higher demand compared to production by 2026, which will give a scarcity period. However, the production is expected to increase toward 2030 and 2040 [4], giving a situation where Norway is back in surplus. In this dataset, Norway is therefore set to be in a scarcity situation. The demand is adjusted from 137 TWh to 200 TWh. To simplify the process, the increase in demand is equally distributed between the 11 areas representing Norway in the dataset.

9.3 Dataset H: Norway in a surplus situation

Opposite to dataset G, this dataset will represent Norway in a surplus situation. Toward 2030, Norway is expected to increase the amount of variable renewable production and again be in a surplus situation [5]. The demand is kept at 200 TWh as in dataset G, while the production is scaled up to 245 TWh. Both wind- and solar production for all Norwegian areas are increased with a factor of 4,13. This is chosen to see what effect a large power surplus will have on the different cases. The world is aiming for net-zero emissions in 2050. For this to be achievable, the power production from renewable energy sources must be increased to phase out fossil sources. In addition, these resources must cover a greater demand than before. The power surplus in Norway is represented by the increase of wind- and solar production as the amount of variable renewable power production is expected to increase [4]. The Norwegian government has in May 2022 set a goal to increase the offshore wind production by 30 GW by 2040, which makes up around a yearly production of 120 TWh. The Norwegian demand today is around 140 TWh, making the increase in offshore wind production a substantial part of the total Norwegian production [10].

9.4 Scenario E: High rationing price

For this part of the thesis, a new scenario is added, as it is interesting to investigate how a high rationing price can affect Norway in a scarcity and surplus situation. In part 2.3, it is discussed that there is no common price for rationing, but typical values used in models are 20-30 NOK/kWh [9]. In this case it is investigated how doubling the rationing price affects the results. In the base case the rationing price is set to 3000 øre/kWh and will in this scenario be doubled to 6000 øre/kWh. Case E will only be run with the -1 an -2 parametrization.

9.5 Case matrix for Norway in different situations

Table 10: Case Matrix for Norway in different situations

Case /Dataset:	**Base**	**+ Cutting overseas cables from Norway (Scenario C)**	**+ Increasing capacity to Great Britain (Scenario D)**	**+Increase in rationing price (Scenario E)**
Dataset F: Base	F-1	FC-1	FD-1	FE-1
	F-2	FC-2	FD-2	FE-2
Dataset G: Noway in scarcity	G-1	GC-1	GD-1	GE-1
	G-2	GC-2	GD-2	GE-2
Dataset H: Norway in a large surplus	H-1	HC-1	HD-1	HE-1
	H-2	HC-2	HD-2	HE-2

10 Scarcity and surplus situations

Towards 2030, an expectation is that Norway will end up in a deficit situation, where the electricity production will be lower than the consumption [5]. On the other hand, an increase in production is expected from 2030 and onward, resulting in a power surplus [5]. Nonetheless, how will Norway in scarcity endure different circumstances relative to when in excess? This part of the thesis investigates how Norway in the base dataset, Norway in scarcity, and Norway in large surplus are affected by scenarios C, D, and E. Will removing the subsea cables from Norway, increasing the capacity to Great Britain, and a higher rationing price have different effects on Norway in the different situations? It is interesting to look at Norway in scarcity, as it is a possible future situation and can support the need to increase the amount of variable renewable energy production. All the scenarios will be run with the -1 and -2 parametrizations presented in part 6. The results from the two parametrizations are discussed in part 10.4. In this part of the thesis, one has used areas Sorland, Sorost, Vestmidt, Norgemidt and Finnmark to present the results.

10.1 Area prices

This part presents duration curves for the area prices of all simulated weather years, comparing the original dataset with Norway in scarcity and in a large surplus situation. Further, duration curves are presented for the base scenario, the scenario where subsea cables out of Norway are removed, when the capacity to Great Britain is scaled up, and when the rationing price is increased. These results are given for the three different datasets. Since the results are similar for the different areas in Norway, only the results for Vestmidt and two figures for Norgemidt are presented in this part. The results for other areas can be found in Appendix N, 13.14. For each situation, both a figure presenting the whole duration curve and a figure presenting a smaller section of the curve to better see the details are presented.

Base cases

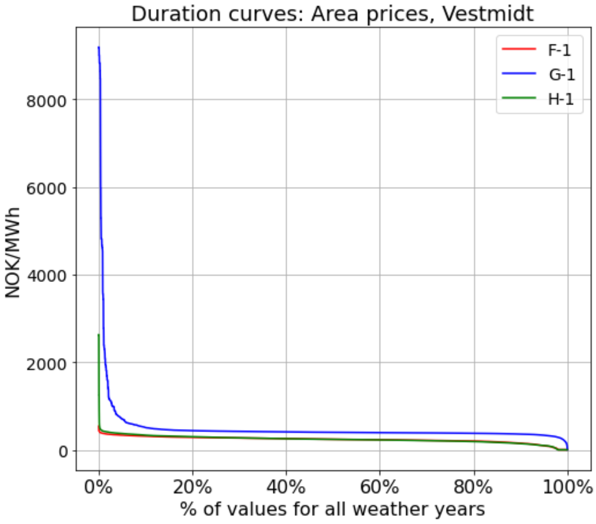

Figure 99: Duration curves for the area prices for Vestmidt for the base cases

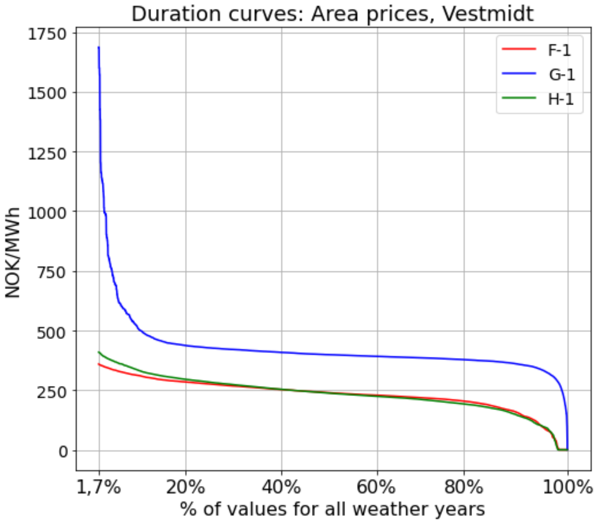

Figure 100: Duration curves for the detailed area prices for Vestmidt for the base cases

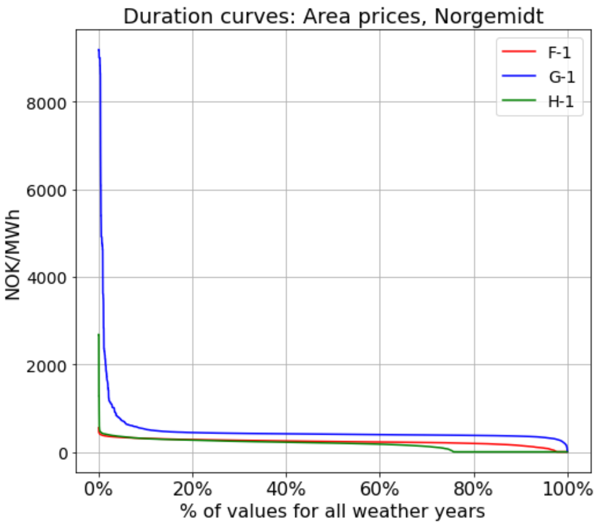

Figure 101: Duration curves for the area prices for Norgemidt for the base cases

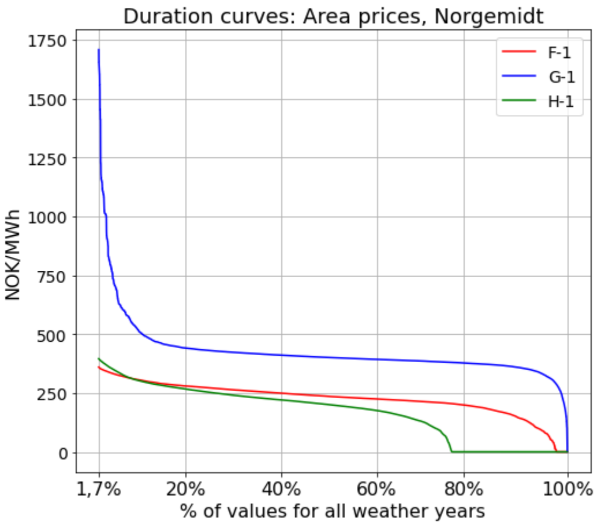

Figure 102: Duration curves for the detailed area prices for Norgemidt for the base cases

Dataset F

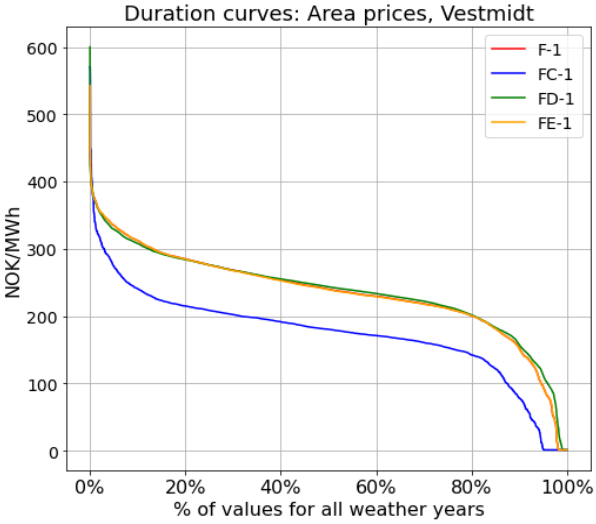

Figure 103: Duration curves for the area prices for Vestmidt for dataset F

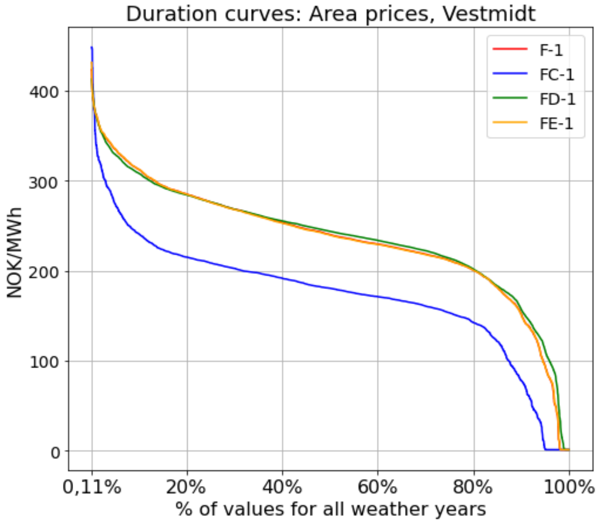

Figure 104: Duration curves for the detailed area prices for Vestmidt for dataset F

Dataset G

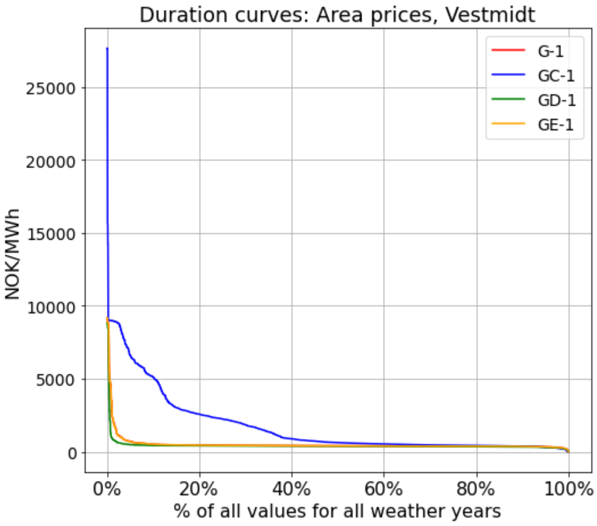

Figure 105: Duration curves for the area prices for Vestmidt for dataset G

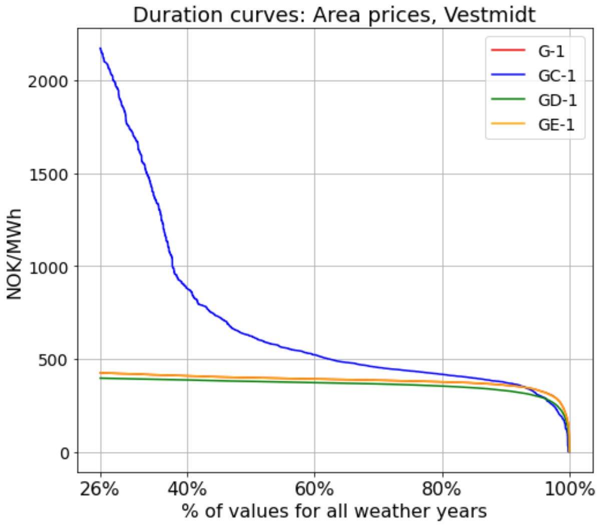

Figure 106: Duration curves for the detailed area prices for Vestmidt for dataset G

Dataset H

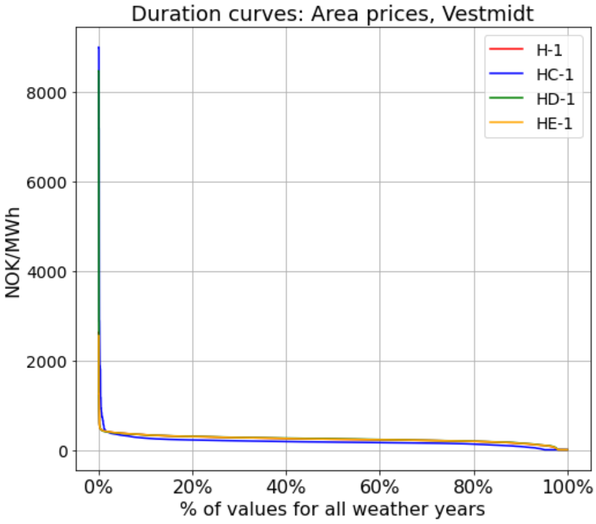

Figure 107: Duration curves for the area prices for Vestmidt for dataset H

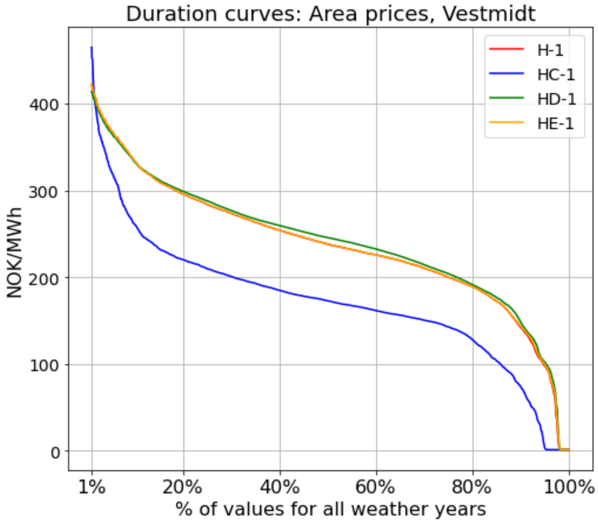

Figure 108: Duration curves for the detailed area prices for Vestmidt for dataset H

In figures 99, 100, 101 and 102, the base cases are presented for Vestmidt and Norgemidt. Looking at the area prices for the scarcity dataset G, one can see that these prices generally are higher than for the surplus datasets F and H. The peak value for dataset G with scarcity is around 9000 NOK/MWh, which is significantly higher than the peak values for H and F. In addition, in the detailed figure, one can observe a difference of 100-200 NOK/MWh between dataset G and the rest for a substantial part of the curve.

The difference between the two surplus scenarios, F and H, are marginal for Vestmidt, while the curves for Norgemidt differ. In the figures 101 and 102, a subset of the area prices for dataset H lies at zero. In part 10.3, one can see that increasing the amount of wind- and solar production leads to a large power surplus in Norgemidt. This contributes to the low prices in comparison to F.

Figures 103 and 104 present the different curves for the scenarios run on dataset F. The peak values for all instances show much lower values than G and H. It is clear from the blue line that removing the subsea cables leads to lower area prices for Norway in a surplus situation. Increasing the capacity to Great Britain, represented by the green line, does not affect Vestmidt greatly. In contrast, an increase in rationing price, seen from the yellow line, gives almost identical prices.

Looking at the curves for all the scenarios run on dataset G, found in figures 105 and 106, one finds the opposite of what is observed for F. When removing all the subsea cables out of Norway, the area prices increase. From part 7, one can observe that removing the subsea cables leads to a decrease in the Norwegian area prices when being in a surplus. On the contrary, when Norway is in a scarcity situation, the prices increase. Compared to the surplus situations the differences of the curves range from about 250-8000 NOK/MWh, seen in 99 and 100. One can, in this situation, see that disconnecting the subsea cables leads to extreme electricity prices when in a scarcity situation. One can see the benefit of increased capacity to Europe when scaling up the capacity to Great Britain. The result is a slight decrease in the area prices. This emphasizes the importance of external connections to Norway, especially when the production is lower than the demand. For a high rationing price, only critical periods are affected. The curve representing a high rationing price is identical to the curve for the base case except for the first values.

For dataset H, when Norway is in a large surplus, one can from figures 107 and 108 observe similar tendencies as for F, the base dataset. When Norway is in a surplus situation, the area prices will experience a decrease when removing the subsea cables. Increasing the capacity to Great Britain gives an insignificant increase in area prices, as increased capacity leads to more equalized prices. The peak value of the curve is affected, but mostly there are only minor changes. This further shows how this increase will not significantly impact the power prices in Norway when being in a surplus. A higher rationing price does not give a change in prices. In a large surplus, Norway will have little risk of rationing. Therefore, it will have a negligible effect.

Removing the subsea cables from Norway will decrease the power prices if in a surplus. Nevertheless, it will lead to extreme prices if the country is in a scarcity situation. As mentioned earlier, the future is uncertain. The development of variable renewable sources is necessary to cover the increasing demand, mainly to decrease electricity prices in the coming years. Increasing the capacity to Great Britain will decrease the prices in a scarcity situation, substantiating the importance of the subsea cables. In surplus, the increase in capacity will lead to little change. Only a slight increase can be observed.

Area differences

The difference in average hourly area prices between areas in Norway for datasets G and H are presented in figures 109 and 110 respectively. The figures present average hourly prices for an average, a dry, and a wet year with seasonal differences. Summer consists of June, July, and August, while for winter, December, and January and February for the following year are used.

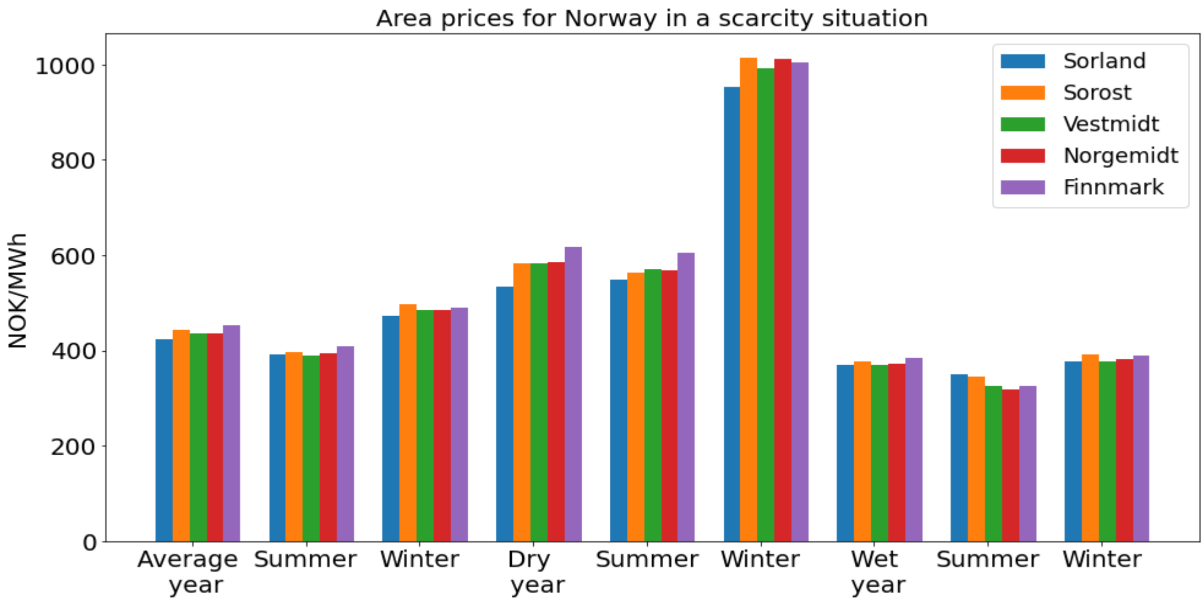

Figure 109: Bar chart for G-1 for the average hourly area prices in the areas for average-, dry- and wet year with seasonal differences

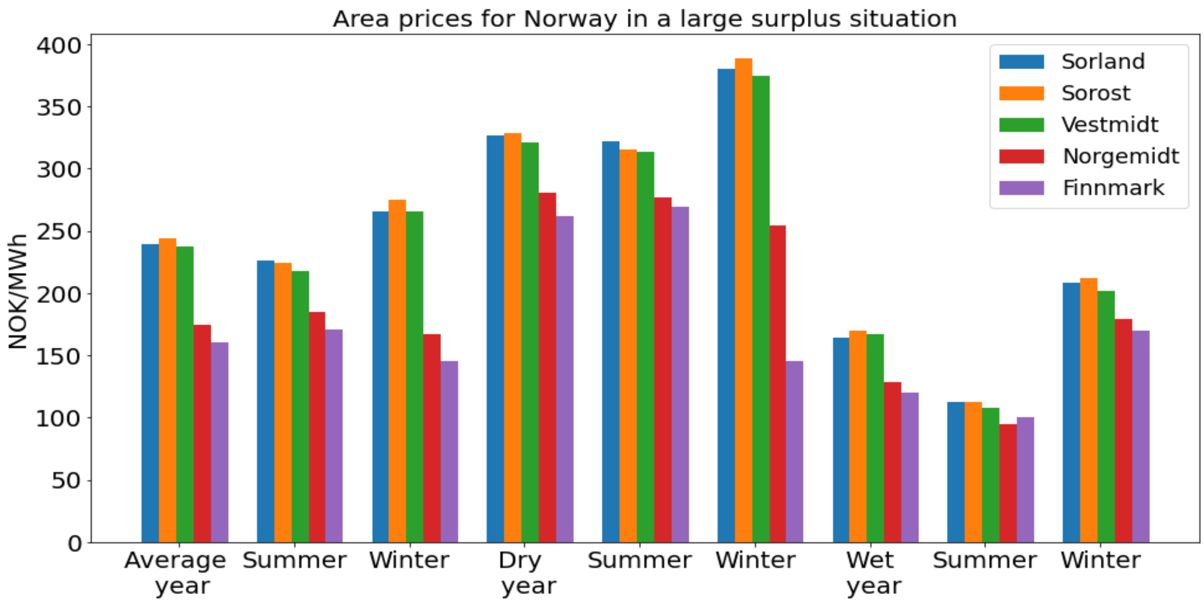

Figure 110: Bar chart for H-1 for the average hourly area prices in the areas for average-, dry- and wet year with seasonal differences

In part 7, one found that the average area prices for Finnmark were lower than the average area prices in the mid and the south of Norway. For the scarcity situation, presented in figure 109, the opposite can be observed. For the dry year, the summer season gives higher average prices for Finnmark than the rest. The area has the highest average prices for most years and seasons. Looking at the map in figure 120, Finnmark is in a production deficit, explaining the increase in prices. Compared to dataset H in figure 110, the average prices between the areas are more similar, and the price levels are generally higher for G as Norway is in scarcity.

On the contrary, Finnmark has the lowest average price for Norway in a large surplus. One can from figure 110 see the same differences as in part 7. Sorland, Sorost, and Vestmidt are the areas with the highest average prices. Norgemidt is also observed to experience much lower area prices than the Southern parts of Norway. The winter season for the dry year gives the biggest differences in area prices, while in the wet year, prices are more equalized. In general, both the average year and the dry year show the distinction in area prices between the Northern- and the Southern parts of Norway.

10.2 Reservoir levels

The figures 111-114 present the percentiles for the reservoir level for Blåsjø and Frøystøl for the different datasets. Figures for two smaller reservoirs, Vrenga and Nore 1 can be found in Appendix O, 13.15.

Base

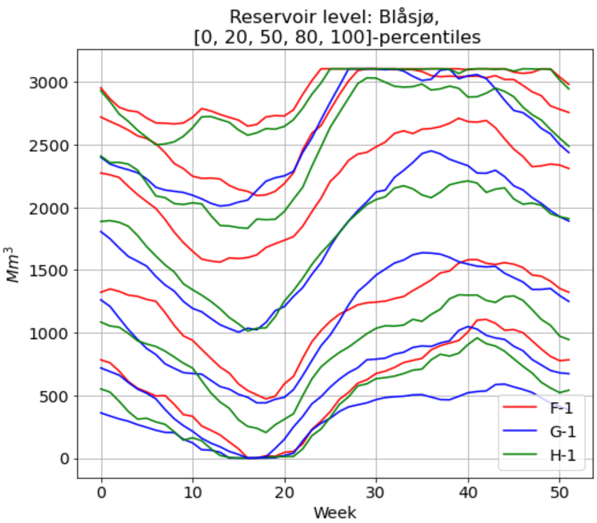

Figure 111: Percentiles for the reservoir level for Blåsjø for the base cases

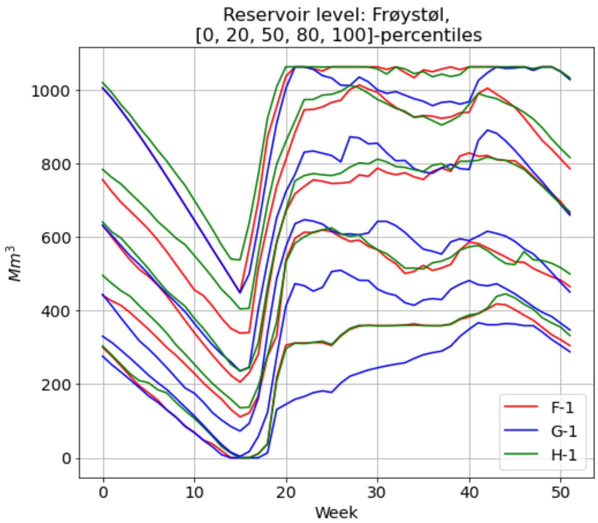

Figure 112: Percentiles for the reservoir level for Frøystøl for the base cases

Removing cables

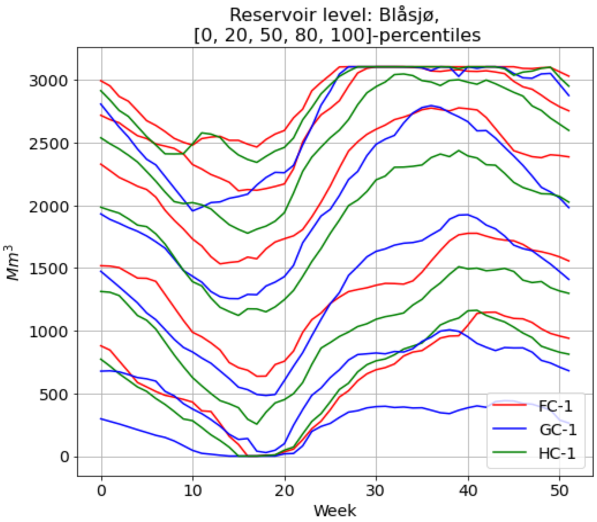

Figure 113: Percentiles for the reservoir level for Blåsjø for FC, GC and HC

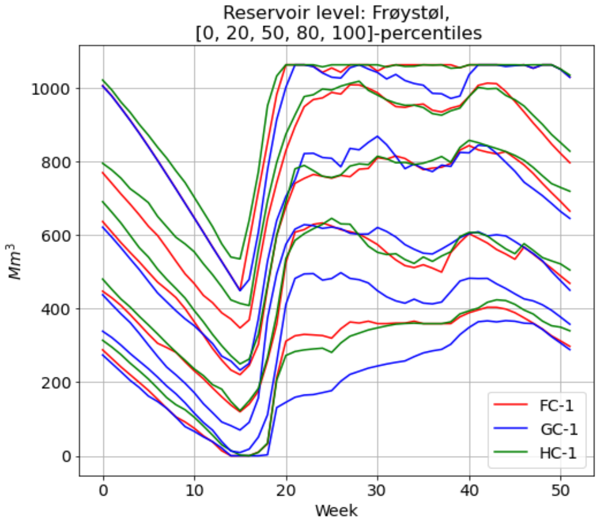

Figure 114: Percentiles for the reservoir level for Frøystøl for FC, GC and HC

Scaling up the capacity to GB

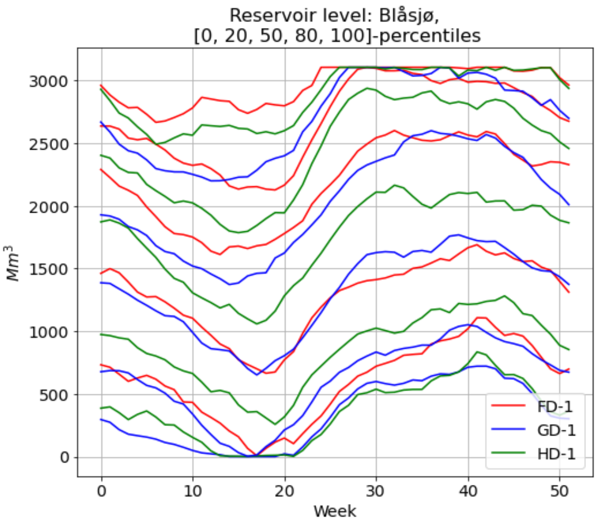

Figure 115: Percentiles for the reservoir level for Blåsjø for FD, GD and HD

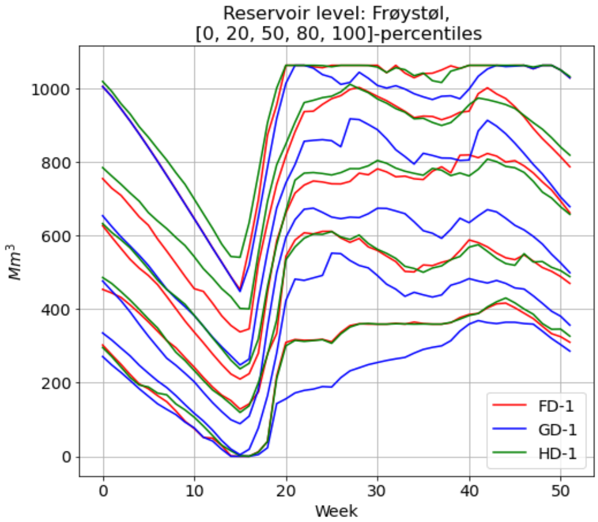

Figure 116: Percentiles for the reservoir level for Frøystøl for FD, GD and HD

High rationing price

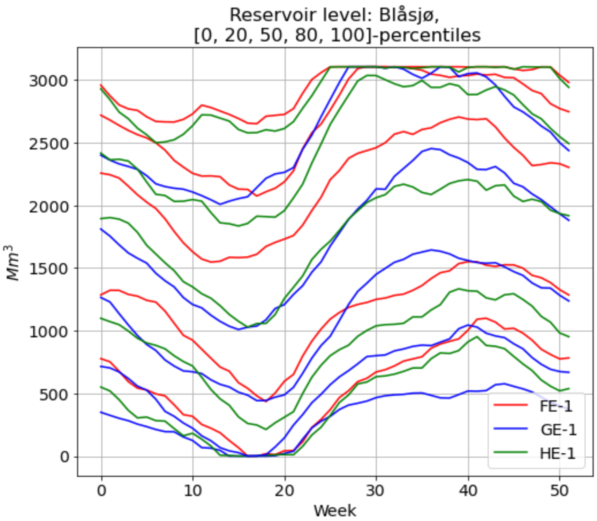

Figure 117: Percentiles for the reservoir level for Blåsjø for FE, GE and HE

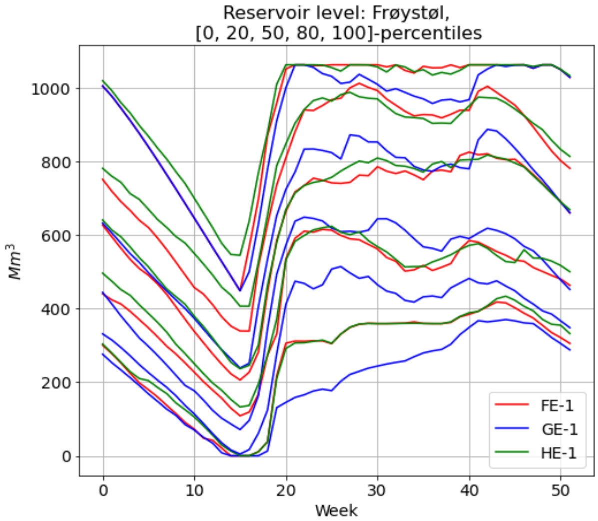

Figure 118: Percentiles for the reservoir level for Frøystøl for FE, GE and HE

For the base, removing subsea cables, scaling up the capacity to GB, and a higher rationing price, one can, from the figures in this part observe how there is less spillage for dataset G than for the base dataset F and dataset H. One can also see how the curves for G have more extended periods where the 0-percentile is at 0, leading to more rationing. The percentile curves for G generally lie lower than the base and surplus dataset curves. It is clear that the 20-percentile for dataset G also goes down towards rationing in the different scenarios, as opposed to datasets F and H. This coincides with the claim that Norway, in scarcity, will need to use more of the reservoir capacity and has a higher probability of rationing.

The green curve, representing the dataset where Norway is in a larger surplus with increased wind and solar production, generally lies lower than the curve for the base dataset. From this, one can see that increasing wind and solar production allows one to exploit the water more flexibly and favorably.

The same tendencies can be seen in both Blåsjø and Frøystøl. There are more minor differences for the smaller reservoirs, substantiating that the smaller reservoirs are not affected significantly by changes to the dataset.

10.3 Power situation

This part presents area maps to observe which areas cover their demand and which areas do not. The maps are presented for F-1, Norway in the base case scenario, G-1, Norway in scarcity, and for H-1, Norway in a large surplus. Green represents an area in balance or surplus, while red represents an area in scarcity. The numbers show the average surplus- or deficit production in TWh. A positive number indicates how many TWh the area is in surplus, while a negative number indicates the lack of production to fulfill the demand.

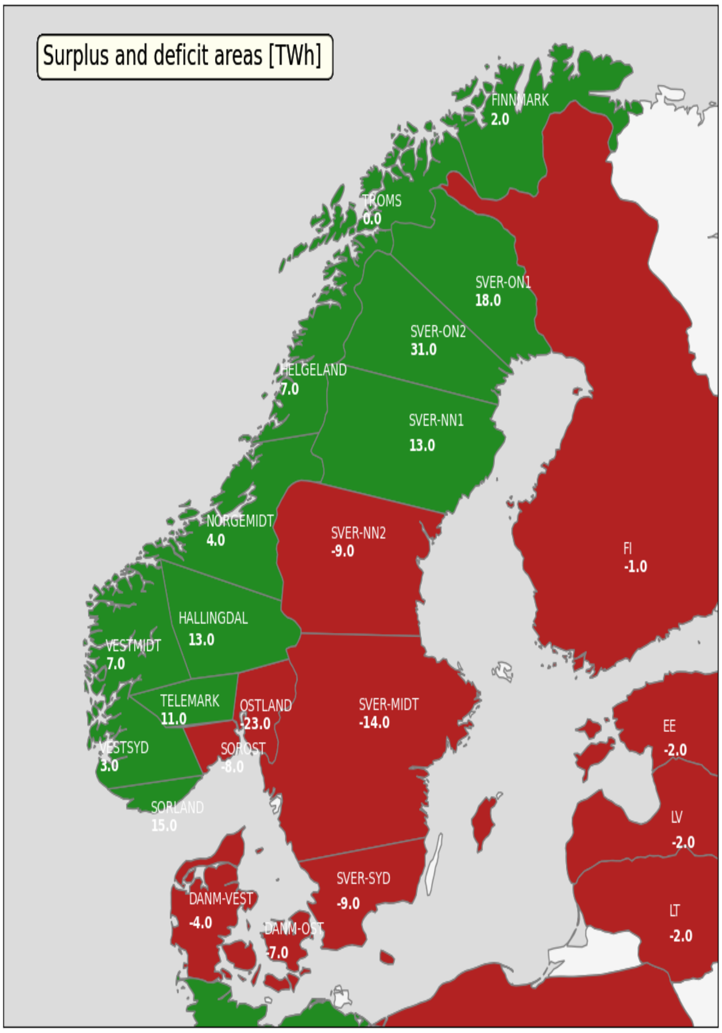

Figure 119: Yearly average production minus yearly average firm demand in TWh for F-1

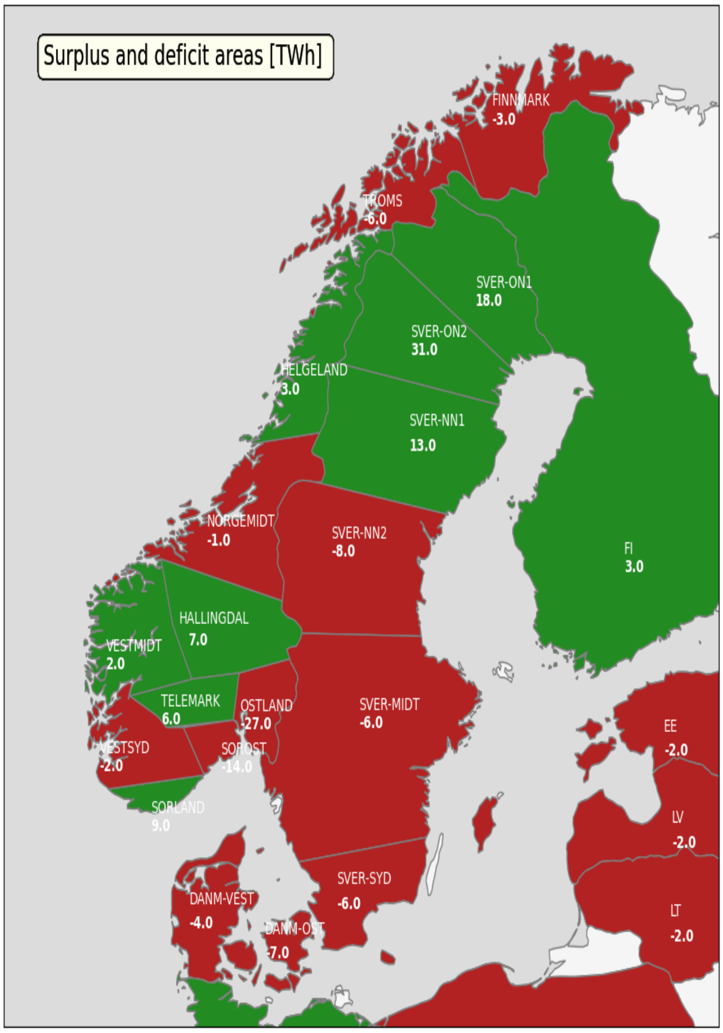

Figure 120: Yearly average production minus yearly average firm demand in TWh for G-1

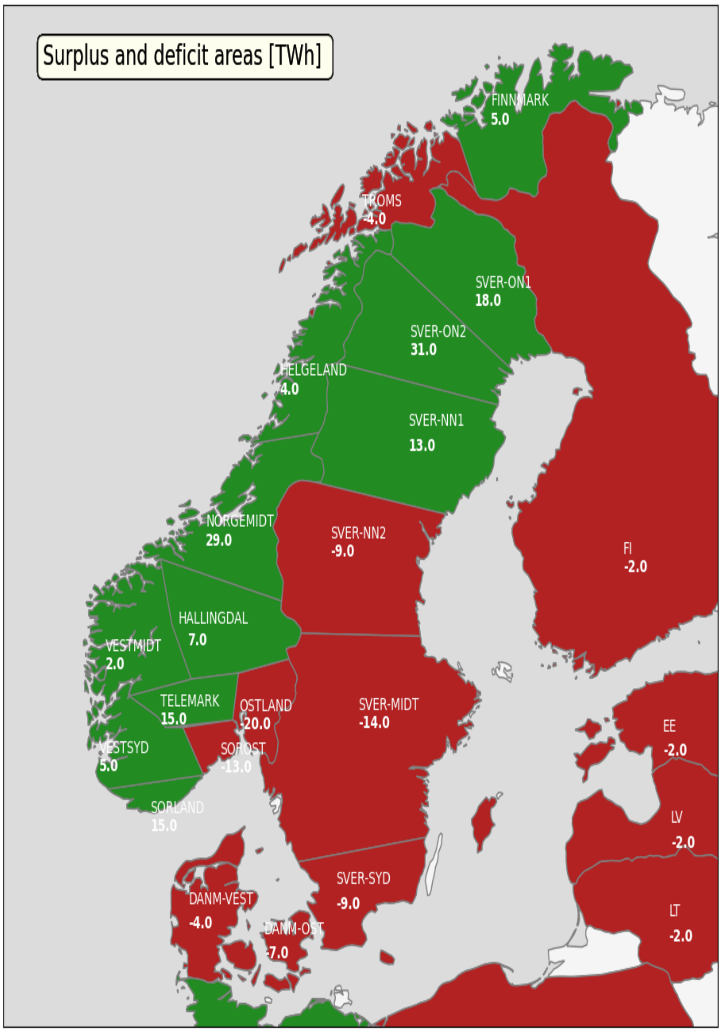

Figure 121: Yearly average production minus yearly average firm demand in TWh for H-1

Flow on lines

The duration curves for the flow on the lines Sorland to Danm-Vest, Sorland to Tysk-Nord, Sorland to Nederland, and Vestsyd to GB-Mid are presented in this part in figures 122 to 125. The cases presented are F-1, G-1, and H-1, to see how the transmission change between the datasets. In addition, the flow on the lines comparing G-1 and GD-1 is presented in the figures 126 to 134, for both the subsea connections and the transmission cables to Sweden. When the values are positive, Norway exports and when the values are negative Norway imports power.

Base cases

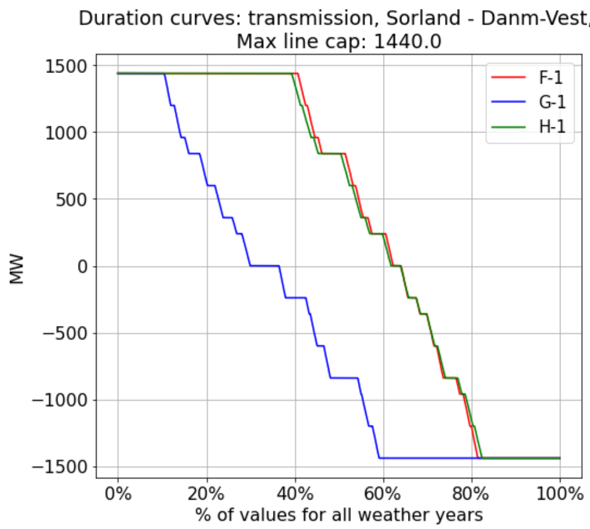

Figure 122: Flow on the line from Sorland to Danm-Vest for the base cases

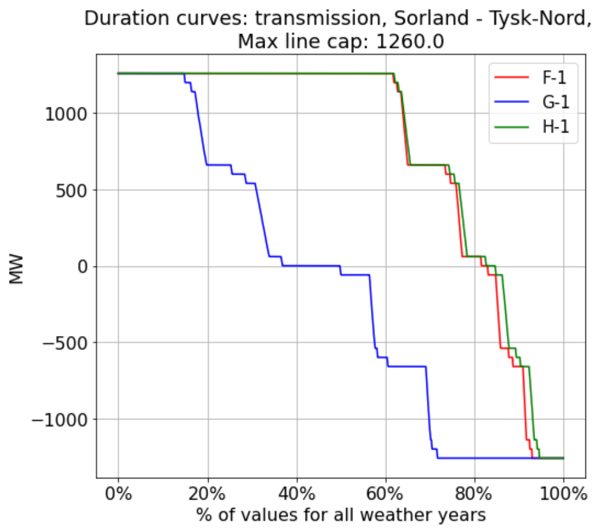

Figure 123: Flow on the line from Sorland to Tysk-Nord for the base cases

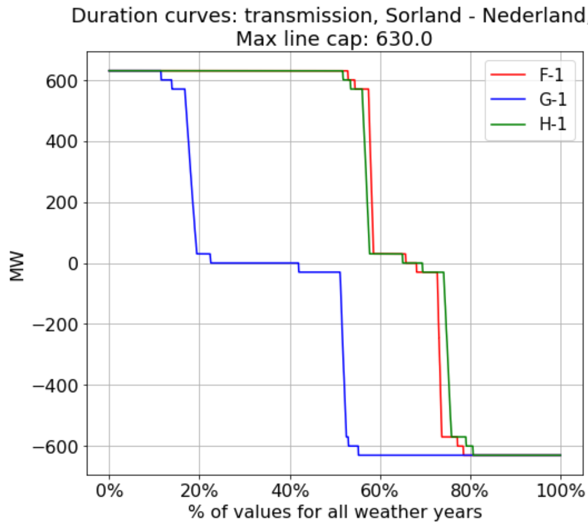

Figure 124: Flow on the line from Sorland to Nederland for the base cases

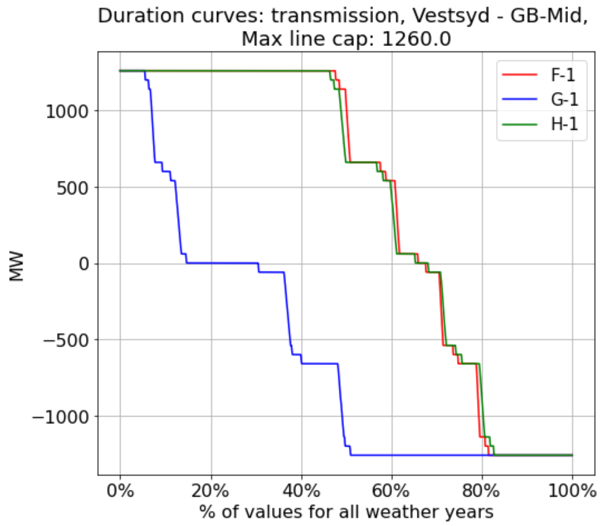

Figure 125: Flow on the line from Vest-Syd to GB-Mid for the base cases

Dataset G

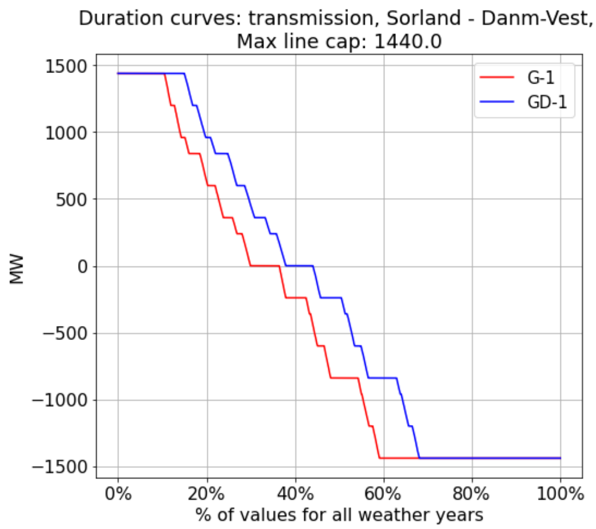

Figure 126: Flow on the line from Sorland to Danm-Vest for G and GD

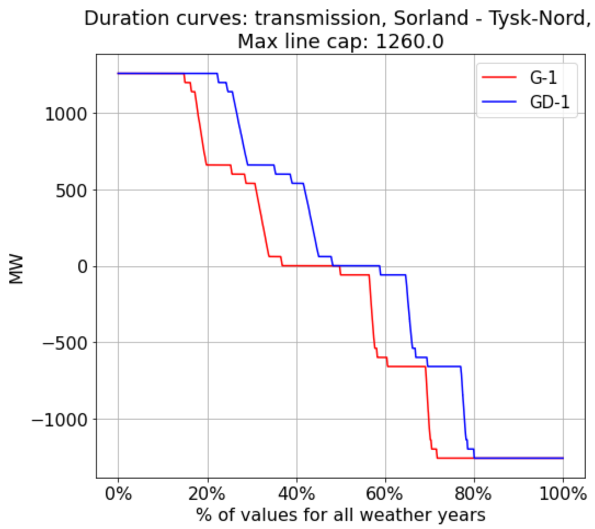

Figure 127: Flow on the line from Sorland to Tysk-Nord for G and GD

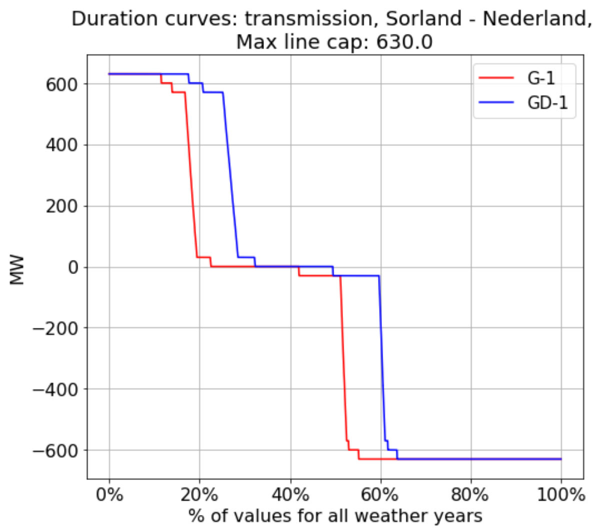

Figure 128: Flow on the line from Sorland to Nederland for G and GD

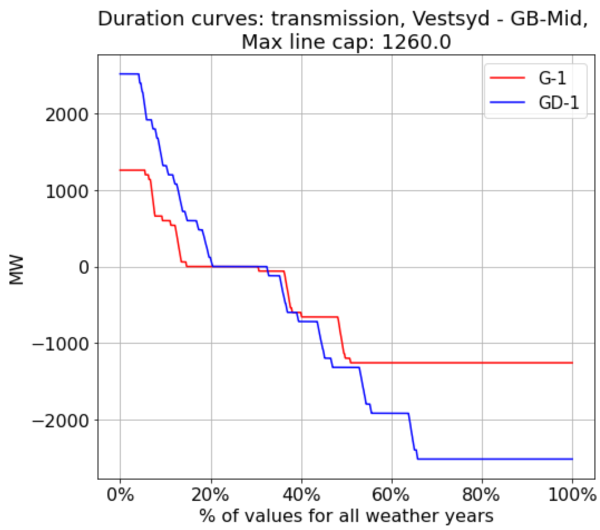

Figure 129: Flow on the line from Vest-Syd to GB-Mid for G and GD

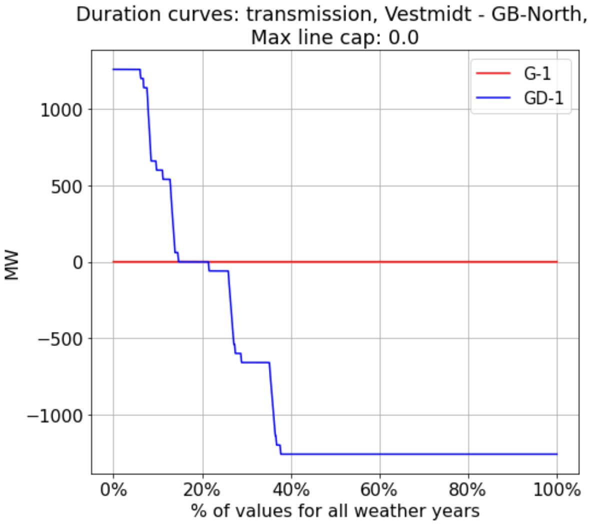

Figure 130: Flow on the line from Vestmidt to GB-North for G and GD

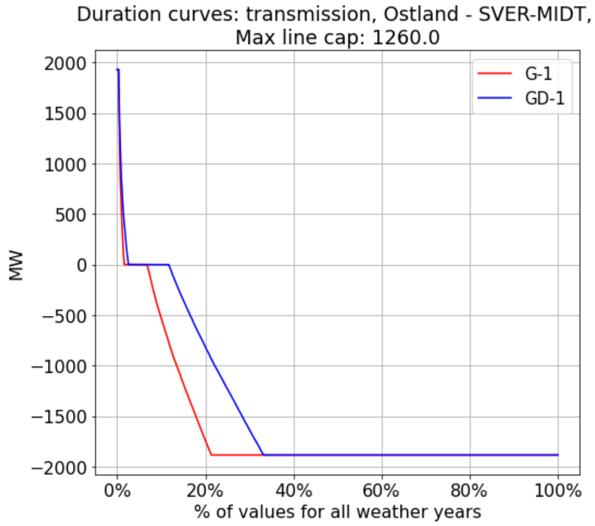

Figure 131: Flow on the line from Ostland to SVER-MIDT for G and GD

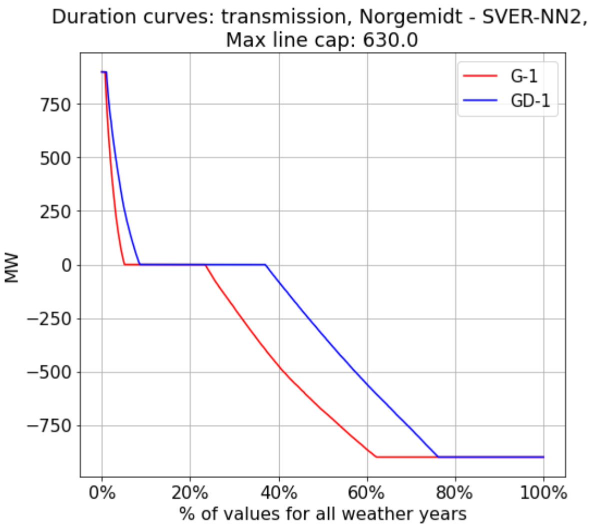

Figure 132: Flow on the line from Norgemidt to SVER-NN2 for G and GD

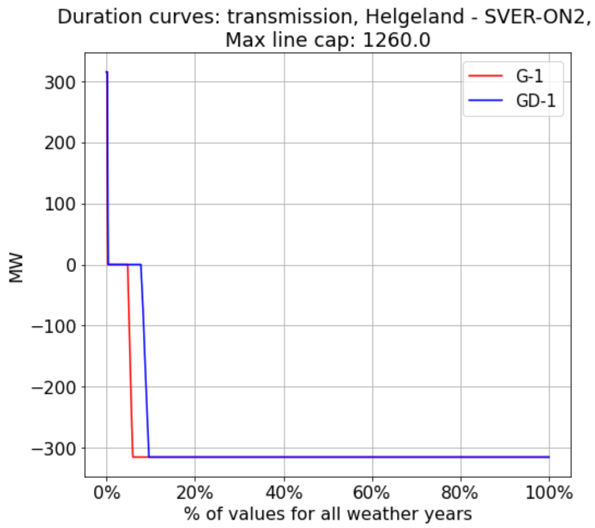

Figure 133: Flow on the line from Helgeland to SVER-ON2 for G and GD

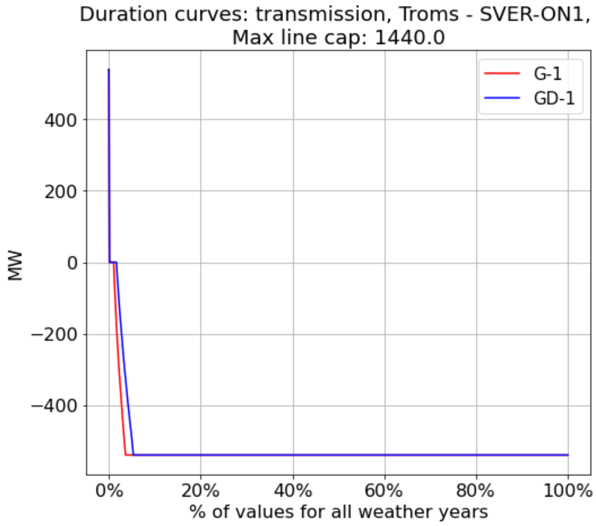

Figure 134: Flow on the line from Troms to SVER-ON1 for G and GD

This part shows a map presenting the state of the areas for cases F-1, G-1, and H-1. These are found in figure 119 for case F-1, in figure 120 for G-1 and in 121 for H-1.

One can observe that the areas Norgemidt, Vestsyd, Troms, and Finnmark go from being in surplus to deficit from F-1 to G-1. For the areas which remain green, one can observe that the surplus decreases with an amount ranging from 4-6 TWh. When increasing the amount of wind- and solar production in H-1, Finnmark, Norgemidt, and Vestsyd change to surplus areas. Norgemidt experiences a drastic increase in average production surplus with a 30 TWh increase from G-1 to H-1. In addition, one can see increased average production in the areas of scarcity.

When Norway is in a scarcity situation, where multiple areas cannot cover their demand, the need for imports will increase. This can be observed in the duration curves presented in the figures 122 to 125. For G-1, one can observe that the amount exported decreases relative to F-1 while the amount imported increases. This supports the claim that subsea cables are crucial for Norway in the future if a scarcity situation occurs. For H-1, the export will again increase compared to G-1, giving similar levels as in F-1.

In dataset G, when Norway is in a scarcity situation, the change in import and export between G-1 and GD-1 on the subsea cables can be seen in the figures 126-130. From the figures 129-130, it is clear that the amount of power imported from Great Britain experiences a significant increase when the capacity on these cables is increased. Looking at the other connections, the amount of export from Norway increases, and imports decrease. This shows how export from Great Britain is preferable and how the flow on lines is displaced to fulfill the energy balances better. The transmission on the cables between Norway and Sweden can be observed in the figures 131-134. The duration curves are presented for the base case G-1 and the scenario GD-1, where the capacity between Norway and Great Britain is increased. One can observe how the number of imports decreases in GD-1 compared to G-1 on all transmission lines between Norway and Sweden. The displacement of power shows how increasing the capacity to Great Britain contributes to relieving the connections between Norway and Sweden.

10.4 Parametrization

This part of the thesis presents differences between the parametrizations for the cases of Norway in scarcity and surplus. One looks at social welfare, area prices, and reservoir levels in this section. In part 8, five and six different parametrizations were run on the different scenarios. Based on the results, a conclusion was that an increase from 4 to 10 scenarios gives a better simulation and that 10 scenarios may often be enough. Based on this conclusion, it was decided to use the -1 and -2 parametrizations in this part to investigate further if these results will be validated.

The different results will be presented first, before they are discussed in part 10.4.5.

10.4.1 Social welfare

The tables 11-14 present the average social welfare for the three different datasets, F, G, and H, for the base, when removing the subsea cables, increasing the capacity to Great Britain and for a high rationing price. All with both the parametrizations -1 and -2. The first column in each table presents the -1 parametrization, while the second presents the -2 parametrization. For the -2 parametrization, both the result and the difference relative to -1 are presented.

Table 11: Average social welfare for F, G and H

Social welfare [Mkr]	
F-1	**F-2**
64617533,45	64617755,36 + **221,91**
G-1	**G-2**
66193144,84	66193466,26 +**321,42**
H-1	**H-2**
66213627,00	66213822,24 +**195,24**

Table 12: Average social welfare for FC, GC and HC

Social welfare [Mkr]	
FC-1	**FC-2**
64609980,60	64610223,95 +**243,35**
GC-1	**GC-2**
66176510,82	66178433,09 +**1922,27**
HC-1	**HC-2**
66206137,90	66206193,30 +**55,4**

Table 13: Average social welfare for FD, GD and HD

Social welfare [Mkr]	
FD-1	**FD-2**
64620567,11	64620743,66 **+176,55**
GD-1	**GD-2**
66197442,75	66197775,17 **+333,42**
HD-1	**HD-2**
66216449,52	66216645,73 **+196,21**

Table 14: Average social welfare for FE, GE and HE

Social welfare [Mkr]	
FE-1	**FE-2**
111038257,56	111038474,30 **+216,74**
GE-1	**GE-2**
114104890,54	114105148,57 **+258,03**
HE-1	**HE-2**
114125291,93	114125487,24 **+195,31**

10.4.2 Area prices

This part presents the average hourly area prices, and the differences between the two parametrizations for the different datasets and scenarios.

Dataset G

Table 15: Mean hourly area prices for the parametrizations G-1 and G-2

Cases/ Areas	G-1	G-2
Sorland	463,28	462,46 **-0,82**
Sorost	502,61	499,72 **-2,89**
Vestmidt	493,19	490,19 **-3,00**
Norgemidt	497,81	494,76 **-3,05**
Finnmark	603,64	568,23 **-35,41**

Table 16: Mean hourly area prices for the parametrizations GC-1 and GC-2

Cases/ Areas	GC-1	GC-2
Sorland	1708,44	1615,64 **-92,8**
Sorost	1752,14	1657,62 **-94,52**
Vestmidt	1704,21	1611,86 **-92,35**
Norgemidt	1615,88	1543,38 **-72,5**
Finnmark	1676,43	1576,88 **-99,55**

Table 17: Mean hourly area prices for the parametrizations GD-1 and GD-2

Cases/ Areas	GD-1	GD-2
Sorland	399,99	398,24 **-1,75**
Sorost	426,51	431,84 **-5,33**
Vestmidt	413,78	419,02 **-5,24**
Norgemidt	422,14	427,16 **-5,02**
Finnmark	548,54	506,72 **-41,82**

Table 18: Mean hourly area prices for the parametrizations GE-1 and GE-2

Cases/ Areas	GE-1	GE-2
Sorland	463,61	462,53 **-1,08**
Sorost	501,77	500,41 **-1,36**
Vestmidt	492,43	490,88 **-1,55**
Norgemidt	497,56	495,42 **-2,14**
Finnmark	593,44	567,09 **-26,35**

Dataset H

Table 19: Mean hourly area prices for the parametrizations H-1 and H-2

Cases/ Areas	H-1	H-2
Sorland	240,91	239,01 **-1,9**
Sorost	246,79	245,03 **-1,76**
Vestmidt	239,55	237,82 **-1,73**
Norgemidt	174,27	172,77 **-1,5**
Finnmark	175,73	171,64 **-4,09**

Table 20: Mean hourly area prices for the parametrizations HC-1 and HC-2

Cases/ Areas	HC-1	HC-2
Sorland	184,52	184,99 **+0,47**
Sorost	196,12	196,82 **+0,7**
Vestmidt	189,04	189,44 **+0,4**
Norgemidt	139,19	138,18 **-1,01**
Finnmark	143,64	139,70 **-3,94**

Table 21: Mean hourly area prices for the parametrizations HD-1 and HD-2

Cases/ Areas	HD-1	HD-2
Sorland	248,65	247,14 **-1,51**
Sorost	253,86	252,19 **-1,67**
Vestmidt	243,55	241,91 **-1,64**
Norgemidt	175,82	174,20 **-1,62**
Finnmark	177,15	172,47 **-4,68**

Table 22: Mean hourly area prices for the parametrizations HE-1 and HE-2

Cases/ Areas	HE-1	HE-2
Sorland	241,30	239,09 **-2,27**
Sorost	247,06	244,94 **-2,12**
Vestmidt	239,82	237,94 **-1,88**
Norgemidt	174,56	172,70 **-1,86**
Finnmark	176,37	171,12 **-5,25**

10.4.3 Reservoir level

The 0-, 20-, 50-, 80- and 100-percentile for the reservoir level between the different parametrizations are in this part presented for the different scenarios run on dataset G and H.

Dataset G

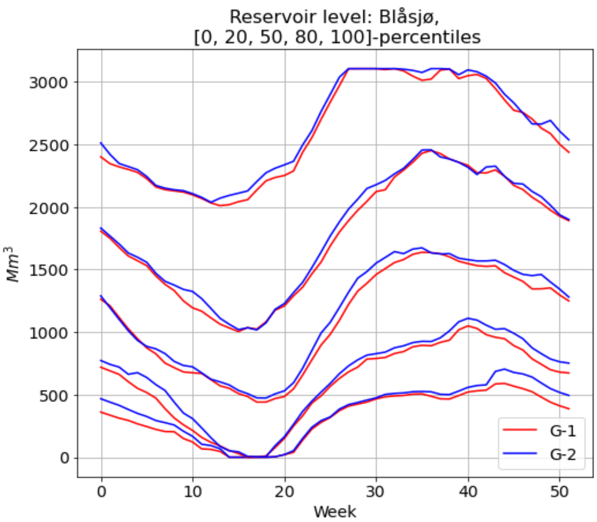

Figure 135: Percentiles for the reservoir level for Blåsjø for G-1 and G-2

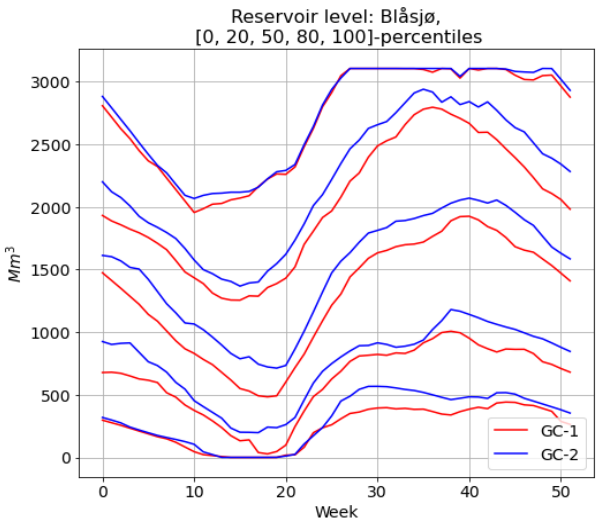

Figure 136: Percentiles for the reservoir level for Blåsjø for GC-1 and GC-2

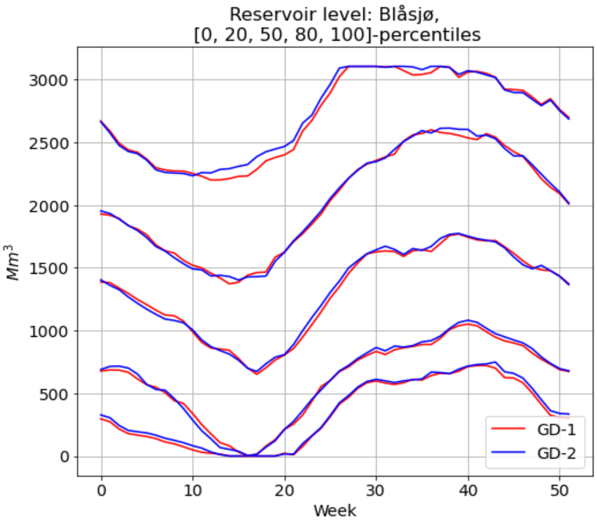

Figure 137: Percentiles for the reservoir level for Blåsjø for GD-1 and GD-2

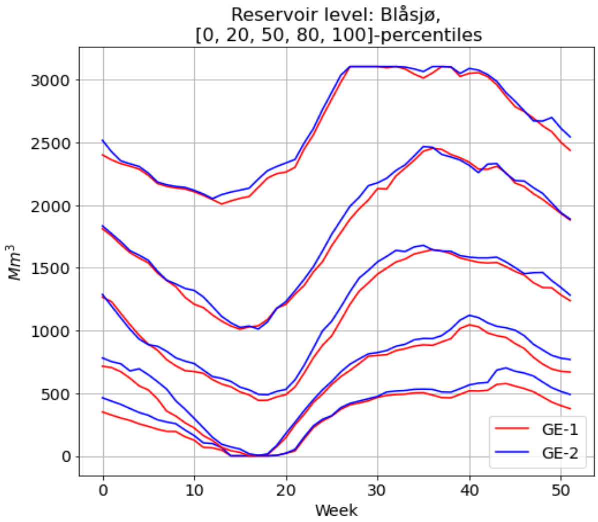

Figure 138: Percentiles for the reservoir level for Blåsjø for GE-1 and GE-2

Dataset H

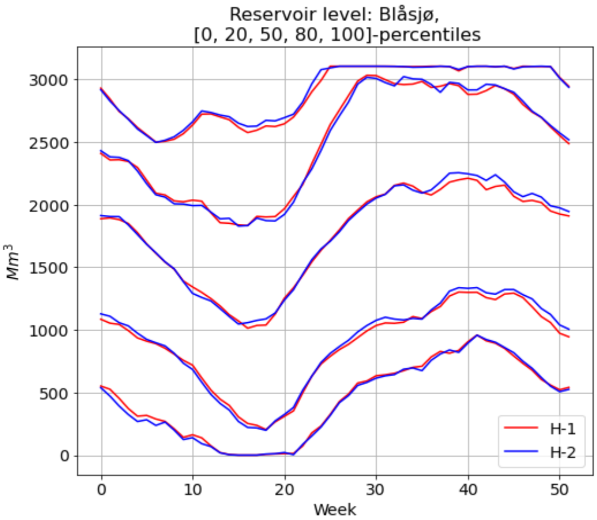

Figure 139: Reservoir level for Blåsjø for H-1 and H-2

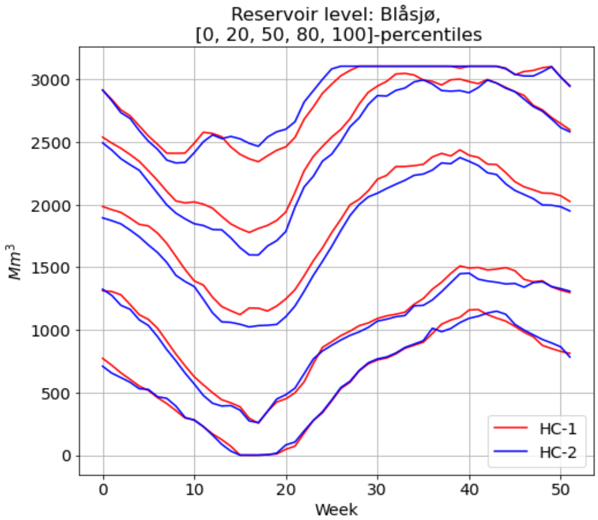

Figure 140: Percentiles for the reservoir level for Blåsjø for HC-1 and HC-2

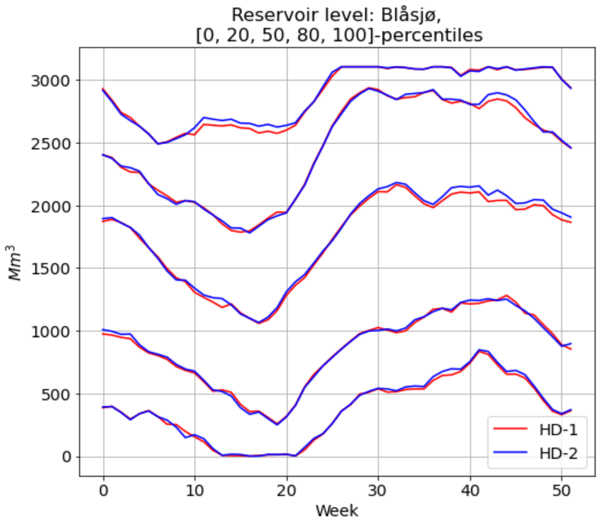

Figure 141: Percentiles for the reservoir level for Blåsjø for HD-1 and HD-2

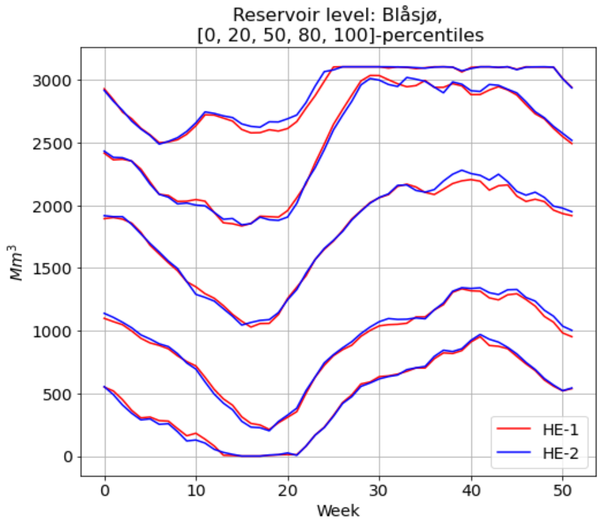

Figure 142: Percentiles for the reservoir level for Blåsjø for HE-1 and HE-2

10.4.4 Model run time

The model run time for the datasets and scenarios run for this part of the thesis is presented in table 23. For more detailed information, see Appendix M, 13.13.

Table 23: Model run time for Norway in different situations

Model run time			
F-1	**FC-1**	**FD-1**	**FE-1**
40h, 19min	57h, 18min	40h, 47min	47h, 58min
F-2	**FC-2**	**FD-2**	**FE-2**
47h, 51min	69h, 8min	51h, 6min	46h, 52min
G-1	**GC-1**	**GD-1**	**GE-1**
42h, 17min	41h, 43min	37h, 7min	40h, 6min
G-2	**GC-2**	**GD-2**	**GE-2**
42h, 47min	53h, 3min	46h, 14min	49h,30min
H-1	**HC-1**	**HD-1**	**HE-1**
40h, 27min	41h, 58min	37h, 45min	41h, 28min
H-2	**HC-2**	**HD-2**	**HE-2**
50h, 7min	52h, 1min	44h, 50min	48h, 57min

10.4.5 Discussion

Social welfare

From the tables presenting social welfare in part 10.4.1, one can observe that the -2 parametrizations with 10 scenarios in the scenario fan, for all datasets and scenarios, give a better result than the -1 parametrizations with 4 scenarios. As discussed in part 8, the number of scenarios in the scenario fan is important and gives a better representation of uncertainty to the model.

From table 12, one can observe that GC-2 gives a drastically better social welfare than GC-1, compared to the difference between the parametrizations for the other scenarios. In dataset G, Norway is in a scarcity situation. For scenario C, all the subsea cables out of Norway are removed. As discussed in part 10.1, this leads to a drastic increase in the Norwegian area prices. Generally, there is a higher increase in social welfare between the -1 and -2 parametrizations for dataset G compared to the rest. This shows the more significant effect of this parametrization on Norway in scarcity than Norway in surplus. The social welfare here shows how more information and less uncertainty in the simulation are even more important when the system is in a pressured situation.

One can conclude that more scenarios in the scenario fan will always give a better simulation. This seems even more important in datasets and scenarios where the system is in a critical situation, leading to high area prices. The difference between the social welfare for GC-1 and GC-2 in addition to case B in part 8 supports this argument.

Area prices

In part 10.4.2, the area prices and how they differ between parametrization -1 and -2 are presented. For all instances except for some of the areas for scenario HC, one can observe a decrease in the area prices for parametrization -2 compared to -1.

In table 16, one can observe bigger differences between the area prices between GC-1 and GC-2 than for the other scenarios. An interesting observation is the high reduction in price for Finnmark relative to the other areas for all scenarios for dataset G. One can also see a higher decrease in Finnmark in dataset H in the tables 19-22, showing how this area has a higher gain from an increase in scenarios compared to the other. Especially in a scarcity situation.

As concluded in 10.4.1, an increase in the number of scenarios will lead to a better simulation and, in this instance, lower area prices.

Reservoir level

The reservoir level curves, presented with the differences between the parametrizations, can be found in part 10.4.3. One can observe how the 20-percentile, together with the 0-percentile, for GD and GE goes down to the 0-level. The 20-percentile can be observed to go quite low for GC as well. The blue line for the -2 parametrizations lies in these curves higher than the red for the base parametrization. When the 20-percentile goes pretty low, which is not ideal, the higher level for -2 is better than the level for -1, showing a better utilization of water with more scenarios in the scenarios fan.

For H, the reservoir curves seem to show the same amount of rationing and flooding for the two parametrizations. Looking at HC-1 and HC-2, one can observe that for the 80-, 50-, and 20- percentile, the line for HC-2 seems to lie a little lower than the line for HC-1. This shows more utilization of water for -2 than -1.

Model run time
The run times for the datasets and scenarios can be found in table 23. Overall, one can observe that the run time for the -2 optimizations does not differentiate much from the -1 parametrizations. The shortest run time for the -2 parametrization, showing the possible computation time without interference, is around 45 hours. The shortest run time for the -1 parametrizations is around 37 hours. The -2 parametrizations utilize more of the capacity of the CPU as it utilizes more processors than -1. Given the results, where the -2 parametrizations give exclusively better social welfare and mostly lower area prices, one can conclude that using 10 scenarios compared to 4 should be prioritized. In addition, as run time is not drastically increased and the results obtained are better, the -2 parametrization is preferable.

10.5 Main points

This section aims to examine how Norway, in different energy situations, both in scarcity and in large surplus with high shares of variable renewable energy, would be affected by different scenarios. The scenarios investigated are removing the subsea cables from Norway, increasing the capacity to Great Britain, and increasing the rationing price. A question is if the impact of these scenarios will vary when Norway is in different energy situations.

The main points which can be taken from the results and discussion are:

- A general observation of the different power situations is that Norway in scarcity experiences significantly higher area prices than in a surplus situation. In the scarcity dataset, the areas Finnmark, Troms, Vestsyd, and Norgemidt go from having surplus production to being deficit areas, resulting in a decrease in export through the subsea cables and more significant imports. For both the surplus situations, the area prices are similar. Norgemidt has a significant increase in production surplus from the scarcity situation to the case with increased wind- and solar production. This leads to low prices in this area. When Norway is in a large surplus of wind- and solar power, there is a clear distinction in area prices between Norway's Northern and Southern areas.

- The importance of the subsea cables becomes infinitely large when Norway is in a scarcity situation. Removing the subsea cables in a surplus situation leads to lower area prices in Norway, while an extreme increase is observed when

Norway is in scarcity. High peak values for Norway in scarcity and a large surplus can be observed, showing the effect of disconnecting the cables in a critical situation. However, the peak for the scarcity situation is much higher than for the large surplus.

- Increasing the capacity to Great Britain leads to a slight increase in area prices when Norway is in surplus, while a slight decrease is observed for the opposite. When in scarcity, export from Great Britain is preferable compared to the other areas. Larger import from Great Britain is obtained in this situation, while import from the other subsea cables is reduced. The imports on the connections between Norway and Sweden when Norway is in scarcity are reduced with the increased capacity to Britain. This shows how scaling up the capacity of North Sea Link and NorthConnect relieves the connections between Norway and Sweden. When in a surplus with increased capacity to Great Britain, the peak values are affected by this connection.

- Doubling the rationing price has little effect on the different power situations. The observation is that area prices are higher in critical periods, which primarily affects the peak values of the duration curves.

- In part 7 it was found that the average area prices in Finnmark were lower than for areas in the mid-and south of Norway. When Finnmark is in a production deficit in the scarcity dataset, this area experiences the highest average area prices for most of the different years and seasons. In the dataset with a large surplus, with an increase in wind and solar production, Finnmark has lower average area prices compared to the rest.

- From the curves for the reservoir level, it can be observed that the percentiles for the scarcity dataset lie lower than for the surplus datasets. This coincides with the claim that Norway will need to utilize more of its reservoir capacity when in scarcity, which leads to less spillage. However, there is a much higher probability of rationing in this situation. It can also be observed that the reservoir curves lie lower for the dataset in a large surplus than for the base dataset. This shows how an increase in wind and solar production gives the possibility to exploit water more flexibly and favorably.

- The two parametrizations run for these datasets and scenarios further prove how more scenarios in the scenario fan will give a better simulation, resulting in higher social welfare and lower area prices. A challenge when running FanSi is compromising run time and resource use with the quality of the results. For all the datasets and scenarios, run time does not drastically increase when the number of scenarios increases. This assessment validates that more scenarios should be prioritized when choosing a parametrization for running FanSi.

What the energy situation will be in the future is difficult to say, but as technology is evolving, both production and consumption will increase. This section of the master's thesis analyzed if different scenarios would have different effects on Norway in a surplus, larger surplus, or scarcity situation. It is clear that the subsea cables are important for Norway as a security of supply if a scarcity situation should occur in the future. When being in a scarcity situation, the results show that it is detrimental to the Norwegian area prices to disconnect the subsea cables. At the same time, an increase to Great Britain will lower the area prices. The results and discussion conducted in this part show how subsea cables can be essential in fulfilling future energy requirements.

11 Conclusion

In this thesis, two different aspects of FanSi are assessed. A feature investigated is the technical model and how to optimize different datasets through parameters used when running FanSi. An assessment of two parameters is done: the number of scenarios and the number of weeks in the scenario fan. The second aspect assessed is using FanSi as an analysis tool to understand the consequences of different changes to the North-European power system. The cases analyzed are high fuel prices, a high rationing price, removing the subsea cables from Norway, and increasing the capacity from Norway to Great Britain. In addition, FanSi is utilized to elaborate on future energy situations in Norway, running the cases presented above on Norway in scarcity and Norway in surplus situations.

From the results and discussion in this thesis, the following are concluded. All results conducted are measured against a base case.

- Changing the parametrization will mainly affect areas with a significant amount of hydropower like Norway. Increasing the number of scenarios in the scenario fan results in higher social welfare and lower Norwegian area prices for all cases run on the different datasets. The case using 20 scenarios gives a better simulation than 10 but has a longer computational time. It is therefore concluded that 10 scenarios in most cases will be sufficient to achieve adequate results.

- The expectation is that an increase in scenario length will improve social welfare and decrease area prices. A weakness was discovered when simulating results for social welfare when increasing the scenario length. Therefore, a conclusion cannot be drawn about its effect on social welfare. However, an increase in scenario length lowers Norwegian area prices, corresponding to a better simulation. In addition, in a case where both the number of scenarios and the time horizon were increased, the social welfare increased, indicating how a combination is valuable for obtaining better results. An increase in scenario length will benefit the simulation result and should be taken into account when choosing parametrization.

- The model run time increases both with an increase in scenarios and scenario length. The increase is more significant for an increase in scenario length, while the differences between using respectively 10 and 20 scenarios are pretty low. The shortest run times for 10 and 20 scenarios are 42 and 52 hours. For a long time horizon of 104 and 156 weeks, the shortest run times are 107 and 185 hours. This substantiates the claim that an increase in scenarios should be prioritized.

- Higher fuel prices and removing the subsea cables led to lower social welfare for Northern Europe, reflected in higher area prices in Germany and Great Britain. For Norway, higher fuel prices lead to higher area prices. The increased area prices in Northern Europe give producers a higher income while consumer surplus decreases. Removing the subsea cables leads to lower area prices in Norway when in a surplus situation. Here, Norwegian producers lose as export possibilities disappear, while Norwegian consumers gain at lower prices. Increasing the capacity from Norway to Great Britain increases the social welfare due to price equalization. The Norwegian producers benefit as a cause of a new export possibility. The European area prices decrease, while Norway experiences slightly higher prices. A slight decrease in Norwegian area prices is observed for a dry year. This substantiates the importance of subsea cables in the European power system.

- From comparing datasets C-UV and C-MV, it was found that recalculating the end water values will give a better simulation. With the recalculation, the social welfare increases, the area prices decrease, and water utilization is better simulated. Even though the end water values are not calibrated to reflect the real world, the results show improvement when recalculating the values when changes are done to a dataset.

- In a scarcity situation, Norway has increased area prices compared to a surplus situation. It is found that removing the subsea cables will have a much more significant effect on Norway in scarcity compared to a surplus situation, resulting in extreme power prices. The decrease in area prices when increasing the capacity to Great Britain when in scarcity substantiates how these cables are essential security of supply for Norway and the power situation going forward.

- Constructing and running a dataset where Norway has a larger surplus than the base case, where both the consumption and production were increased, did not show large differences in the results. However, there is a clear distinction between area prices in the Northern and Southern parts of Norway for the situation with a larger surplus. With high shares of wind- and solar production, percentiles for reservoir level show how the increase of variable energy sources gives a possibility to exploit water in the reservoirs more flexibly and favorably. When removing the subsea cables from Norway, the high peak values in the larger surplus situation further substantiates how these connections are important and can give fewer price spikes when Norway is in a critical situation.

From the analysis of the different parametrizations, increasing the number of scenarios proved to be superior for all datasets. Augmenting fuel prices has the highest significance for the North-European power market, leading to extremely high prices. Scaling up the capacity from Norway to Britain benefits Northern Europe due to relieving the system of bottlenecks, resulting in higher social welfare. When Norway is in scarcity, the area prices experience an increase. In this situation, removing the subsea cables will be detrimental, which is the opposite of the observations for Norway in surplus. It is clear from the results that the subsea cables have a fundamental role in the European system, lowering area prices and working as a security of supply for the Norwegian power system in critical times.

12 Further work

This thesis finds that more scenarios in the scenario fan, which give less uncertainty to the model, results in a better simulation in all cases investigated. The historical weather data used ranges from the years 1981 to 2010. In further studies, it would be interesting to use more recent data, as the weather today is more uncertain and less stable than before. The weather data also represents quite normal years. Some are drier, some have more precipitation than others, but none are very dry or wet. In the future, more extreme weather is expected. It would therefore also be interesting to include more extreme weather years.

From investigating the parametrization in FanSi, only two different parameters were looked at, the number of scenarios and weeks in the scenario fan. There were run six different parametrization combinations. A base case with 4 scenarios and 52 weeks, two where the number of scenarios was changed to 10 and 20 scenarios, two where the number of weeks was changed to 104 and 156, and one where both the number of scenarios and weeks were changed, 20 scenarios and 104 weeks. In further studies, it would be interesting to look at other parameters as well. It would also be interesting to see if the value of increasing the number of scenarios at one point is saturated. For both 10 and 20 scenarios, the simulations got better, but would there be a large difference between 15 and 20 or 20 and 25?

In Dataset H in the thesis, the production in Norway was adjusted up to 245 TWh by scaling up wind- and solar production. The Norwegian demand in the dataset was set to 200 TWh, giving a surplus of 45 TWh. In the base dataset, the Norwegian surplus is equal to 35 TWh. In the results, the simulations for these two datasets were quite similar, and the different scenarios had a similar effect. Even though there was a larger surplus in H and more wind- and solar production, it could be interesting to have an even larger surplus to see if it would give other results. When increasing the demand in dataset G and wind- and solar production in dataset H, there was an equal distribution in all areas. This was to simplify the changes done to the datasets. Future wind- and solar projects have not been considered when distributing the production, nor have the demand been distributed to fit the expected future increase. It would be interesting to increase demand and production relative to the expectations of the areas.

FanSi is a model that is used mainly for research purposes on a project basis. Norway is modeled in detail, while other countries may not be as well represented. Other datasets should be tested to confirm the validity of the statement from this thesis.

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13 Appendix

13.1 Appendix A: Control file


```xml
<?xml version="1.0"?>
<SOVNCNTR>
<ControlData>
    <Variable> <NAME>        NWEEKSCEN </NAME> <VALUE>               52 </VALUE> <COMMENT>              Number of weeks in the scenario - fan </COMMENT> </Variable>
    <Variable> <NAME>            NSCEN </NAME> <VALUE>                4 </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>                0 </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>   0.10000000D-03 </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>                T </VALUE> <COMMENT> Experimental: Use smoothing of end value setting (T) or (F) </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>               78 </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>   0.50000000D+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>   0.50000000D+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>                T </VALUE> <COMMENT>         Save cut for each iteration, week, year </COMMENT> </Variable>
    <Variable> <NAME>  SAVEWATERVALUES </NAME> <VALUE>                F </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>                F </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>
</WaterValue>
<DEBUG>
    <Variable> <NAME>   SAVEDEBUGGINFO </NAME> <VALUE>                0 </VALUE> <COMMENT>        Save info for each process >0 (0 not use) </COMMENT> </Variable>
    <Variable> <NAME>      LASTWeekSIM </NAME> <VALUE>               52 </VALUE> <COMMENT>   Last week to simulate (0 use values from STFIL) </COMMENT> </Variable>
    <Variable> <NAME>         FYEARSIM </NAME> <VALUE>                1 </VALUE> <COMMENT>                        First year to simulate </COMMENT> </Variable>
    <Variable> <NAME>         NYEARSIM </NAME> <VALUE>               30 </VALUE> <COMMENT>                   Number of years to simulate </COMMENT> </Variable>
    <Variable> <NAME>       LSTARTMAG </NAME> <VALUE>                F </VALUE> <COMMENT>    Start reservoir from resultat/detsimres.h5 [T/F] </COMMENT> </Variable>
    <Variable> <NAME>  LWRITEENERGYFAN </NAME> <VALUE>                T </VALUE> <COMMENT>  Write energy fan after reduction and autoreg [T/F] </COMMENT> </Variable>
    <Variable> <NAME>  LWRITELPPROBLEM </NAME> <VALUE>                F </VALUE> <COMMENT>              Write LPmodel first week [T/F] </COMMENT> </Variable>
    <Variable> <NAME>     LWriteSNOCorr </NAME> <VALUE>                F </VALUE> <COMMENT> Write correlation factor snow/inflow, program will stop </COMMENT> </Variable>
    <Variable> <NAME>    LNEWLPPROBLEM </NAME> <VALUE>                F </VALUE> <COMMENT>        Start with no LP model (cold start) [T/F] </COMMENT> </Variable>
</DEBUG>
<RISK>
    <Variable> <NAME>        SCALHIGH </NAME> <VALUE>   0.00000000D+00 </VALUE> <COMMENT>        Scale a high inflow scenario, >0 to activate </COMMENT> </Variable>
    <Variable> <NAME>         SCALLOW </NAME> <VALUE>   0.00000000D+00 </VALUE> <COMMENT>        Scale a high inflow scenario, >0 to activate </COMMENT> </Variable>
</RISK>
</SOVNCNTR>
```


Figure 143: Control file

13.2 Appendix B: 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'
```

Figure 144: Section of the list of steps

13.3 Appendix C: Output from Samoverskudd

Utskrift av resultat fra Samkjøringsmodellen med Samoverskudd

Middelverdier Simuleringsperiode fra uke 1 til uke 52 Utskriftperiode fra uke 1 til uke 52

Delområde	Produksjon GWh	Konsum GWh	Omraadetap GWh	Snittap GWh	Produsent-overskudd Mkr	Konsument-overskudd Mkr	Flaskehals-inntekt Mkr	TSO overskudd Mkr	Omraadetaps-kostnad Mkr	Snittaps-kostnad Mkr	Magasin-endring Mkr	Samfunnsøkonom-overskudd Mkr
OSTLAND	16815.5	43063.99	0.0	391.1	3864.65	512298.57	259.06	170.03	0.00	89.03	-3.65	516329.60
SOROST	675.7	10311.48	0.0	121.9	150.20	122472.66	42.37	13.26	0.00	29.11	-0.36	122635.76
HALLINGDAL	14355.8	1333.62	0.0	164.8	3355.73	12673.97	40.17	1.67	0.00	38.50	1.33	16032.69
TELEMARK	15477.9	4254.07	0.0	117.7	3656.72	92970.83	35.51	7.68	0.00	27.84	-1.15	96634.08
SORLAND	22832.7	10241.19	0.0	591.6	5558.67	186102.15	2298.15	2172.83	0.00	125.32	-23.15	193810.50
VESTSYD	18202.2	18688.84	0.0	422.3	4336.38	311749.16	854.80	765.82	0.00	88.98	-25.48	316825.89
VESTMIDT	23968.6	19722.24	0.0	146.5	5521.99	354990.94	52.53	19.50	0.00	33.04	-26.57	360505.86
NORGEMIDT	32006.1	30466.77	0.0	230.4	7280.97	614402.74	125.56	72.75	0.00	52.81	-15.68	621740.78
HELGELAND	13455.0	8138.83	0.0	135.6	3058.76	134207.55	96.49	66.10	0.00	30.39	-20.97	137311.43
TROMS	10109.6	10610.77	0.0	83.5	2274.13	219394.53	95.25	78.44	0.00	16.81	-7.93	221739.17
FINNMARK	4450.9	1556.12	0.0	34.7	960.16	17744.95	24.29	16.98	0.00	7.31	0.73	18722.82
SVER-ON1	29667.9	12785.83	0.0	214.6	5335.10	227081.90	373.23	333.09	0.00	40.13	-0.71	232749.38
SVER-ON2	30883.8	1384.91	0.0	343.8	5233.37	0.00	525.90	463.00	0.00	62.90	2.58	5698.95
SVER-NN1	13434.0	0.64	0.0	861.8	3029.37	0.00	961.68	786.55	0.00	175.13	-2.31	3813.61
SVER-NN2	12428.4	21772.73	0.0	143.7	2954.37	389313.46	158.82	129.07	0.00	29.74	-5.65	392391.26
SVER-MIDT	81963.3	96226.76	0.0	1024.4	12827.14	1668474.24	1042.80	821.43	0.00	221.37	4.90	1682127.71
SVER-SYD	16322.8	25948.75	0.0	598.4	3249.74	483953.95	2400.76	2264.97	0.00	135.79	0.14	489468.81
FINLAND	92602.8	93377.33	0.0	288.3	14274.88	1872752.25	873.64	818.21	0.00	55.43	4.98	1887850.33
DANM-OST	9000.8	16449.35	0.0	259.0	1886.17	488734.36	1137.73	1081.95	0.00	55.78	0.00	491702.48
DANM-VEST	19527.4	23719.35	0.0	571.0	4331.02	703748.08	2531.76	2398.98	0.00	132.78	0.00	710478.08
TYSK-OST	135804.5	87138.47	0.0	473.4	34882.58	2253422.80	5102.54	4954.19	0.00	148.35	0.00	2293259.57
TYSK-NORD	65385.0	56315.68	0.0	1219.9	17867.79	1513488.08	5226.64	4855.02	0.00	371.63	0.00	1536210.88
TYSK-MIDT	49295.5	66193.32	0.0	518.1	14526.19	1777730.15	1611.29	1447.87	0.00	163.43	0.00	1793704.21
TYSK-SYD	86706.4	74191.60	0.0	286.1	25334.68	1987785.98	1248.46	1156.15	0.00	92.31	0.00	2014276.82
TYSK-SVEST	44937.3	105564.73	0.0	449.3	13131.12	2836309.97	1925.68	1744.70	0.00	180.99	0.00	2851185.78
TYSK-VEST	122542.1	229846.33	0.0	656.8	32802.58	6174603.27	4103.88	3894.99	0.00	208.89	0.00	6211300.83
TYSK-IVEST	3479.4	0.00	0.0	17.4	1026.84	0.00	8.57	0.03	0.00	8.53	0.00	1026.88
NEDERLAND	86365.5	123306.04	0.0	729.1	17691.95	3657434.57	2547.21	2352.62	0.00	194.59	0.00	3677479.14
BELGIA	54904.0	88412.14	0.0	432.5	11967.39	2622764.03	2655.67	2551.68	0.00	103.99	0.00	2637283.09
GB-SOUTH	93804.9	180996.78	0.0	1031.1	21978.84	5368807.77	2201.70	1930.20	0.00	271.50	0.62	5392717.43
GB-MID	86748.1	151705.82	0.0	985.3	20543.05	4500396.73	6226.20	6023.02	0.00	203.18	0.88	4526963.67
GB-NORTH	63475.8	35044.46	0.0	455.1	7606.78	997604.27	5302.90	5241.59	0.00	61.31	-3.98	1010448.67
NORGEM-OWP	759.3	8.28	0.0	3.8	169.99	0.00	0.86	0.01	0.00	0.85	0.00	169.99
VESTMI-OWP	90.4	1.24	0.0	0.4	21.00	0.00	0.11	0.00	0.00	0.10	0.00	21.00
VESTSY-OWP	82.7	0.46	0.0	0.4	19.16	0.00	0.10	0.00	0.00	0.10	0.00	19.16
SORLAN-OWP	104.3	0.50	0.0	0.5	24.09	0.00	0.12	0.00	0.00	0.12	0.00	24.09
AEGIR-OWP	0.0	0.00	0.0	0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SVER-N-OWP	2047.8	620.17	0.0	7.1	261.26	0.00	1.32	0.01	0.00	1.30	0.00	261.27
SVER-M-OWP	1401.4	0.00	0.0	7.0	299.14	0.00	1.51	0.01	0.00	1.50	0.00	299.16
SVER-S-OWP	157.4	0.00	0.0	0.8	34.38	0.00	0.17	0.00	0.00	0.17	0.00	34.38
FI-OWP	859.0	0.68	0.0	4.3	159.42	0.00	0.81	0.01	0.00	0.80	0.00	159.43
DANM-O-OWP	13198.0	892.08	0.0	61.5	2072.60	0.00	10.48	0.12	0.00	10.36	0.00	2072.73
DANM-V-OWP	16824.5	809.23	0.0	80.1	3554.58	0.00	17.93	0.16	0.00	17.77	0.00	3554.74
TYSK-O-OWP	2446.9	605.06	0.0	9.2	567.17	0.00	2.85	0.02	0.00	2.83	0.00	567.19
TYSK-V-OWP	49452.9	1174.12	0.0	241.4	14711.23	0.00	74.03	0.48	0.00	73.55	0.00	14711.72
NEDERL-OWP	67608.0	1933.50	0.0	571.8	14629.66	0.00	148.31	14.44	0.00	133.86	0.00	14644.11
BELGIA-OWP	17274.5	213.23	0.0	85.3	3431.47	0.00	17.33	0.17	0.00	17.16	0.00	3431.64
DOGGERBANK	11650.0	394.28	0.0	56.3	2629.99	0.00	13.26	0.11	0.00	13.15	0.00	2630.10
GB-N-OWP	70563.6	39248.17	0.0	156.6	4913.95	0.00	52.53	28.16	0.00	24.37	0.00	4942.11
GB-M-OWP	35228.7	580.97	0.0	173.2	6856.50	0.00	34.63	0.35	0.00	34.28	0.00	6856.85
GB-S-OWP	42013.7	163.39	0.0	209.3	8015.03	0.00	40.49	0.42	0.00	40.07	0.00	8015.45
FRANKRIKE	572356.0	524152.41	0.0	381.7	100870.46	15590163.98	6333.21	6249.34	0.00	83.86	-68.63	15697215.15
SVEITS	-12775.0	0.21	0.0	68.6	-6238.02	0.00	32.78	0.14	0.00	32.64	0.00	-6237.88
OSTERRIKE	757.3	212.03	0.0	30.0	-316.83	0.00	12.44	0.06	0.00	12.38	0.00	-316.77
TSJEKKIA	7637.6	904.75	0.0	35.4	221.03	0.00	787.17	773.32	0.00	13.85	0.00	994.35
POLEN	158486.7	185425.33	0.0	225.1	30572.58	5480136.01	2752.89	2685.92	0.00	66.97	49.56	5513444.07
BALTIC	22549.0	29650.45	0.0	176.0	5958.40	878523.01	1160.50	1113.98	0.00	46.51	-2.15	885593.24
Sum	2452404.4	2435759.46	0.0	16585.0	505937.58	64052236.91	63587.05	59501.60	0.00	4085.45	-142.64	64617533.45

Figure 145: Output from Samoverskudd

13.4 Appendix D: A part of the net configuration

```
 1,'MASKENETT', 56,
1,'OSTLAND',2,'SOROST',
2,0,0,
0,2300,2300
1,
0, 1, 52, -230.0, -230.0
1,'OSTLAND',3,'HALLINGDAL',
2,0,0,
0,4800,4800
1,
0, 1, 52, -480.0, -480.0
1,'OSTLAND',4,'TELEMARK',
2,0,0,
0,2000,2000
1,
0, 1, 52, -200.0, -200.0
1,'OSTLAND',8,'NORGEMIDT',
2,0,0,
0,1100,1100
1,
0, 1, 52, -110.0, -110.0
1,'OSTLAND',16,'SVER-MIDT',
2,0,0,
0,2145,2095
1,
0, 1, 52, -214.5, -209.5
2,'SOROST',4,'TELEMARK',
2,0,0,
0,500,500
1,
0, 1, 52, -50.0, -50.0
```

Figure 146: A part of the net configuration for the system

13.5 Appendix E: Detailed information about the dataset

To make the data easier to present, Norway and Sweden are aggregated into the areas Norway South, Norway Mid, Norway North, Sweden North, and Sweden South. Norway South consists of the areas: Ostland, Sorost, Hallingdal, Telemark, Sorland, Vest-Syd and Vest-Midt. Norge-Midt and Helgeland make up Norge Mid, and Troms and Finnmark represent Norway North. Sweden South consists of SVER-ON-1, SVER-ON-2, SVER-NN1, SVER-NN2, SVER-MIDT, and SVER-SYD, while Sweden South only consist of SVER-SYD. All the areas in Denmark, Germany and Great Britain are aggregated to respectively represent each country.

Maximum nuclear, thermal and bio production

Table 24: Maximum production capacity of nuclear, thermal and bio production in **MW**

Country	**Nuclear [MW]**	**Thermal [MW]**	**Bio [MW]**
Norway_S	0,00	152,74	0,00
Norway_M	0,00	10,00	0,00
Norway_N	0,00	0,00	0,00
Sweden_N	160,26	1674,37	1189,42
Sweden_S	0,00	994,63	392,51
Finland	0,00	3803,51	2524,54
Denmark	0,00	2572,31	1240,74
Germany	3246,45	57967,22	7433,85
Netherlands	0,00	12138,85	1784,13
Belgium	0,00	11679,17	892,06
Great Britain	0,00	34342,24	3952,00
France	457,88	9747,05	3853,00
Switzerland	0,00	0,00	0,00
Austria	0,00	0,00	0,00
Czech republic	0,00	0,00	0,00
Poland	343,41	26224,91	2358,00
Baltic	171,70	4220,22	280,00

Renewable production capacity

Table 25: Mean yearly wind power production (WPP) and solar power production (SPP) for countries and areas with offshore wind power (OWP) in **TWh**

Country	**WPP [TWh]**	**SPP [TWh]**
Norway_S	8,28	1,87
Norway_M	9,51	0,20
Norway_N	2,65	0,00
Sweden_N	54,09	2,26
Sweden_S	6,88	0,68
Finland	23,50	1,00
Denmark	13,45	5,16
Germany	152,24	111,79
Netherlands	16,80	27,22
Belgium	11,01	17,55
Great Britain	69,37	30,62
France	124,34	49,61
Switzerland	0,00	0,00
Austria	0,00	0,00
Czech republic	0,00	0,00
Poland	42,11	1,32
Baltic	6,31	0,08

OWP	**WPP [TWh]**
NORGEM-OWP	0,71
VESTMI-OWP	0,09
VESTSY-OWP	0,08
SORLAN-OWP	0,10
AEGIR-OWP	0,00
SVER-N-OWP	1,92
SVER-M-OWP	1,32
SVER-S-OWP	0,15
FI-OWP	0,80
DANM-O-OWP	13,36
DANM-V-OWP	15,70
TYSK-O-OWP	2,33
TYSK-V-OWP	45,94
NEDERL-OWP	62,49
BELGIA-OWP	15,76
DOGGER-BANK	11,25
GB-N-OWP	67,10
GB-M-OWP	33,70
GB-S-OWP	38,32

Details of hydro-based areas

Table 26: Details of the areas with hydro production

Country	Number of reservoirs	Aggregated reservoir capacity [GWh]	Max hydro production capacity [MW]
Norway_S	709	58202,58	23782,45
Norway_M	434	21046,47	7601,78
Norway_N	148	8636,72	2427,46
Sweden_N	201	31762,76	14435,90
Sweden_S	37	1912,16	1766,50
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

Yearly inflow

Denmark, Switzerland, Germany, the Netherlands, Belgium, Austria, and the Czech Republic does not have hydro production and is therefore not in the table.

Table 27: Mean yearly inflow in **TWh** for the hydro production areas

Country	Regulated inflow [TWh]	Unregulated inflow [TWh]	Total inflow [TWh]
Norway_S	112,16	4,83	116,99
Norway_M	38,03	3,43	41,46
Norway_N	13,13	0,64	13,78
Sweden_N	60,64	3,99	64,63
Sweden_S	6,68	0,00	6,68
Finland	15,95	0,00	15,95
Great Britain	5,55	0,00	5,55
France	19,87	49,18	69,05
Poland	0,41	0,27	0,68
Baltic	2,51	0,00	2,51

One reservoir hydro production

For some areas with less detailed input, hydro production is added as production from one reservoir. The capacities for these areas are shown below in table 28.

Table 28: Production of the areas with hydro production represented as one reservoir.

Country	Hydro [MW]
Norway_S	0,00
Norway_M	0,00
Norway_N	0,00
Sweden_N	0,00
Sweden_S	0,00
Finland	0,00
Denmark	0,00
Germany	3246,45
Netherlands	0,00
Belgium	0,00
Great Britain	0,00
France	457,88
Switzerland	0,00
Austria	0,00
Czech republic	0,00
Poland	343,41
Baltic	171,70

13.6 Appendix F: 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 147: Load periods for the system

13.7 Appendix G: List of 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       ,30.00,0.0,30.0,# 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       ,67.5,0.0,30.0,# 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       ,67.5,0.0,30.0,# 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       ,19,0.0,30.0,# 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       ,55.0,0.0,30.0,# Sluttuke, Pris brensel EUR/mmbbl, Avgift brensel EUR/mmbbl, Avgift CO2 i EUR/tCO2
```

Figure 148: List of fuel prices

13.8 Appendix H: Area prices for the different scenarios

Sorost

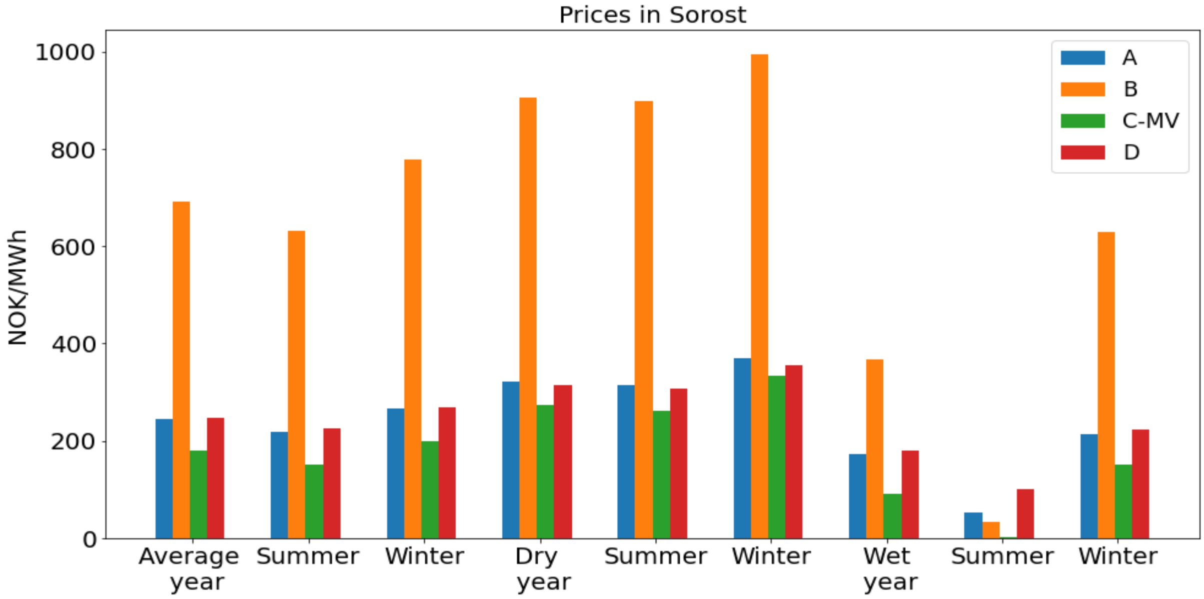

Figure 149: Bar chart for the average hourly area prices in Sorost for average-, dry- and wet year with seasonal differences

Vestmidt

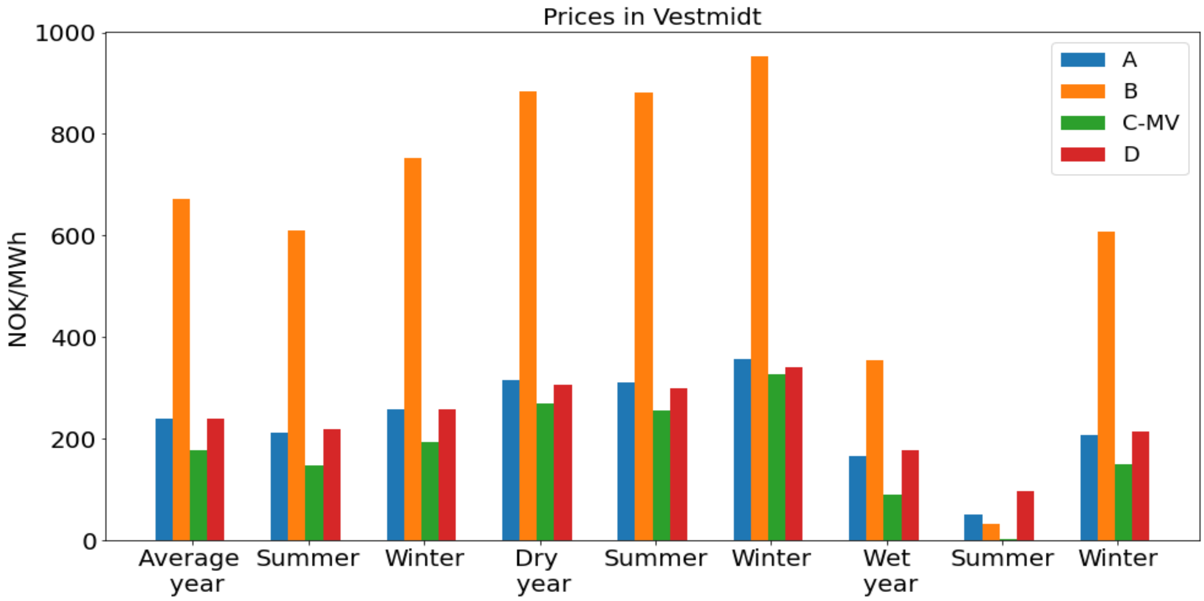

Figure 150: Bar chart for the average hourly area prices in Vestmidt for average-, dry- and wet year with seasonal differences

Norgemidt

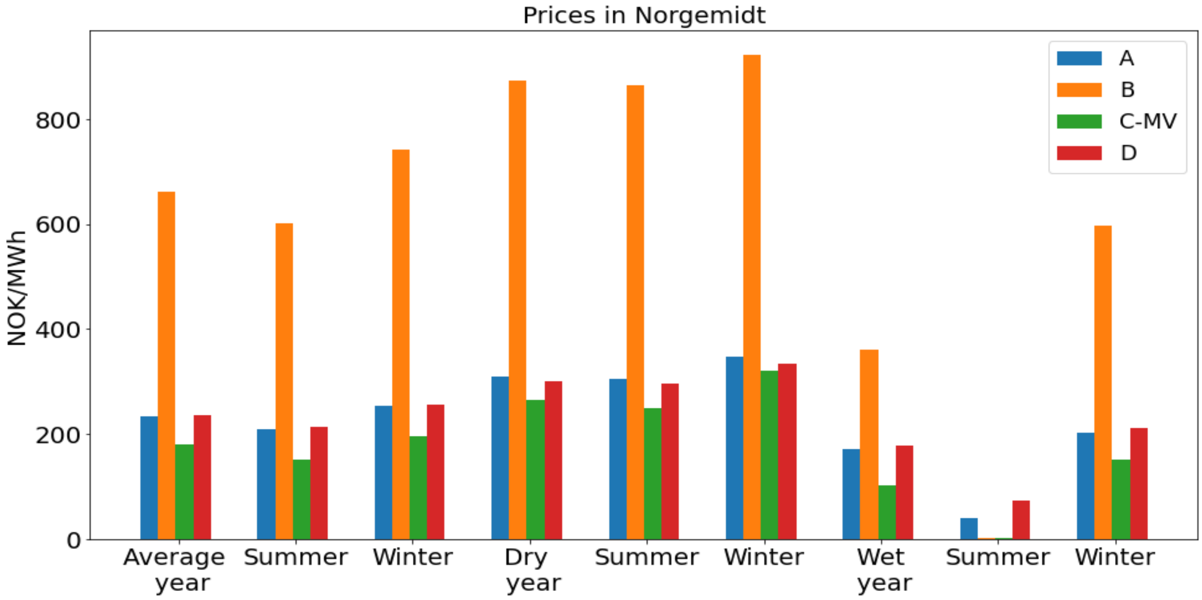

Figure 151: Bar chart for the average hourly area prices in Norgemidt for average-, dry- and wet year with seasonal differences

Finnmark

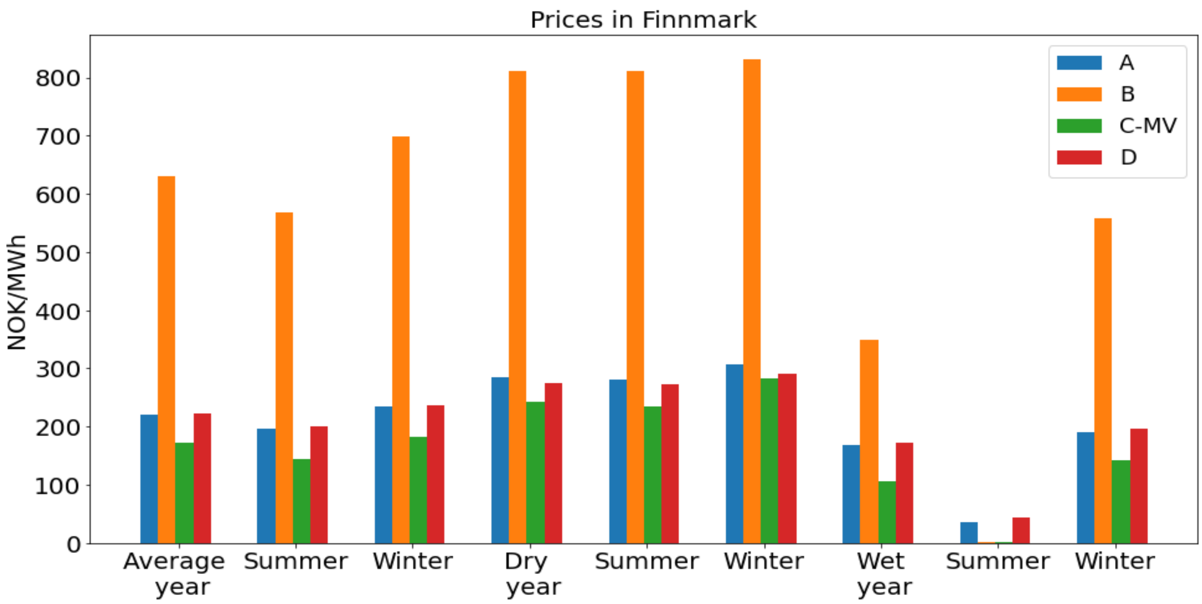

Figure 152: Bar chart for the average hourly area prices in Finnmark for average-, dry- and wet year with seasonal differences

13.9 Appendix I: Plots for area prices for the different datasets

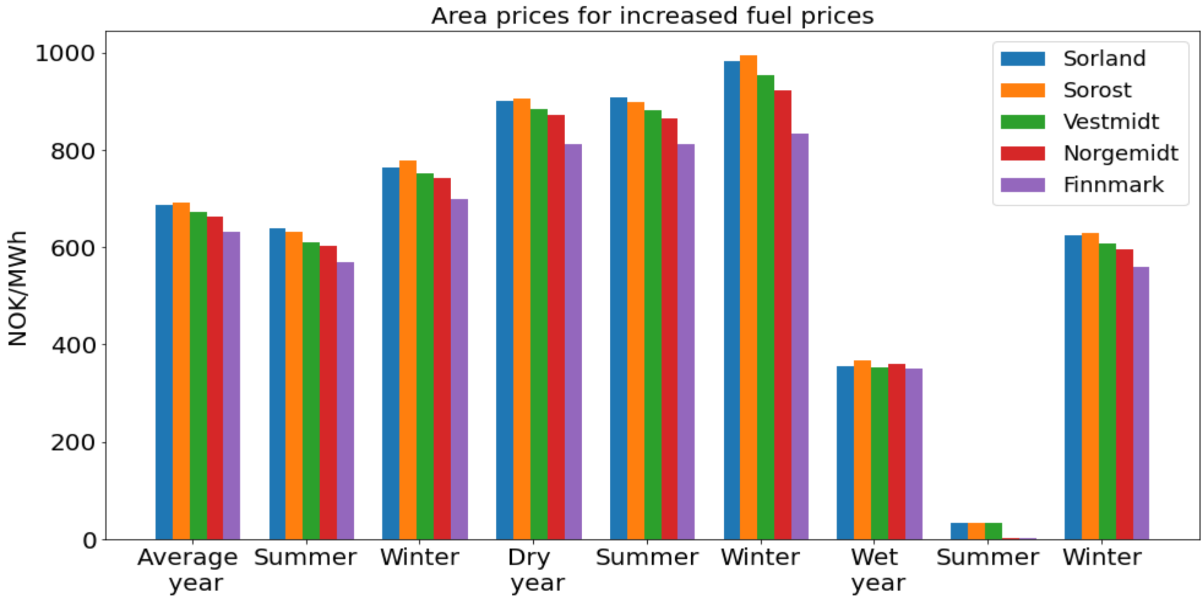

Figure 153: Bar chart for B-1 for the average hourly area prices in the areas for average-, dry- and wet year with seasonal differences

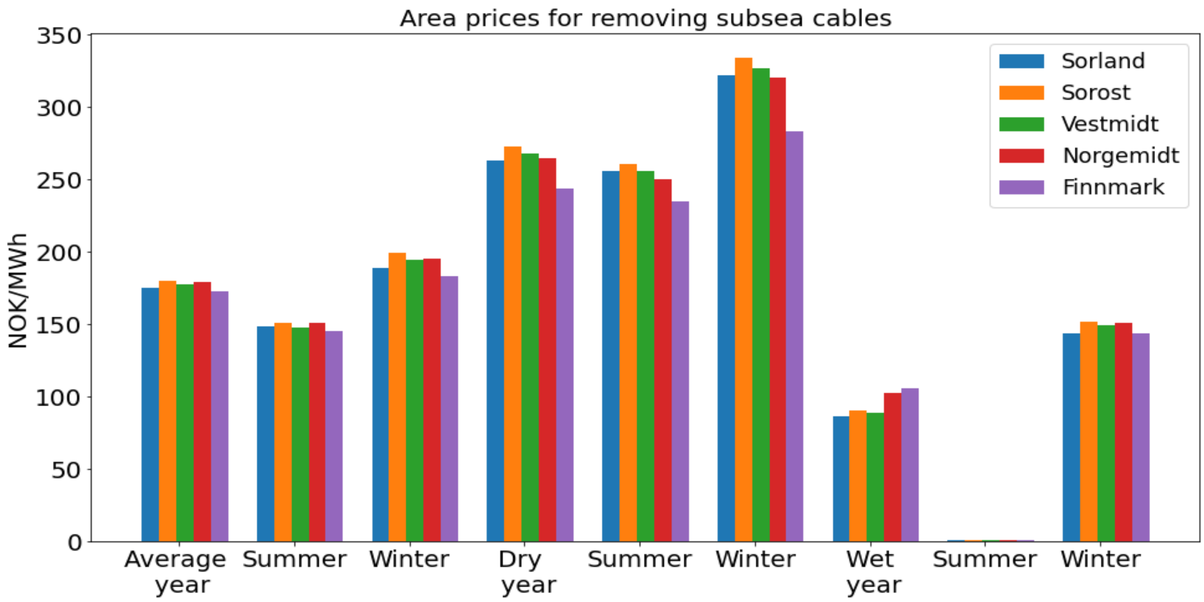

Figure 154: Bar chart for C-MV-1 for the average hourly area prices in the areas for average-, dry- and wet year with seasonal differences

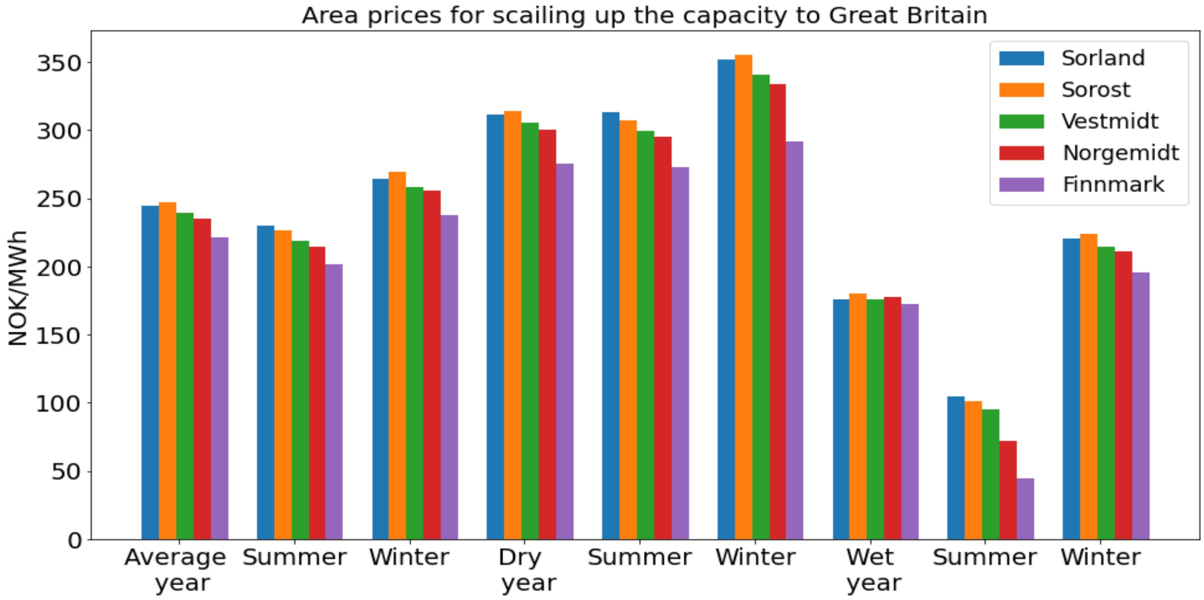

Figure 155: Bar chart for D-1 for the average hourly area prices in the areas for average-, dry- and wet year with seasonal differences

13.10 Appendix J: Reservoir levels for Nore 1 and Vrenga for the different scenarios

Scenarios A and C-MV

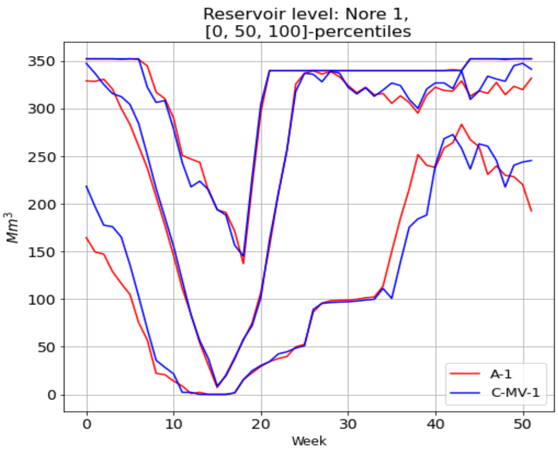

Figure 156: 0-, 50-, 100-percentiles for the reservoir level for Nore 1 for scenarios A and C-MV

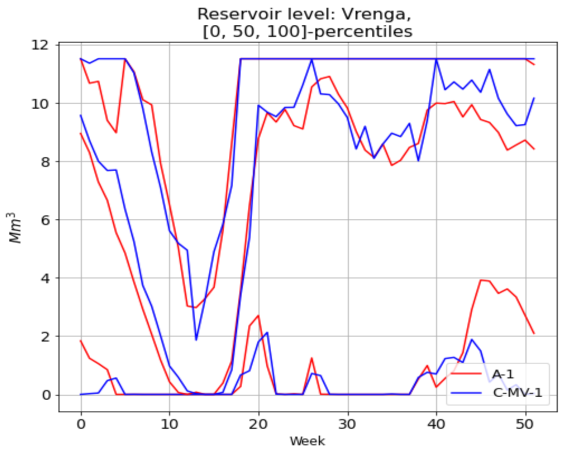

Figure 157: 0-, 50-, 100-percentiles for the reservoir level for Vrenga for scenarios A and C-MV

Scenarios C-MV and D

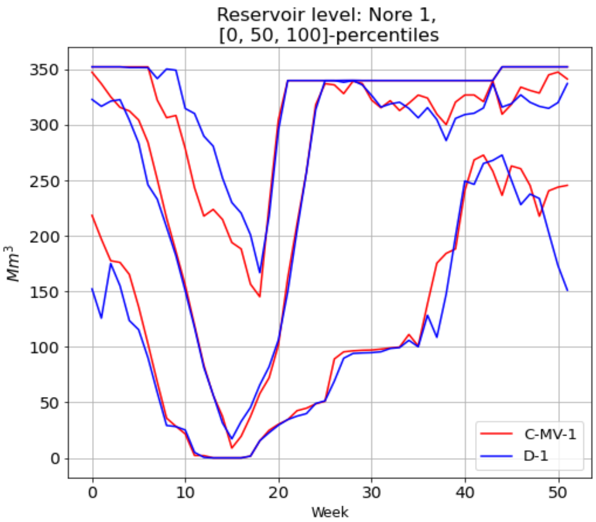

Figure 158: 0-, 50-, 100-percentiles for the reservoir level for Nore 1 for scenarios C-MV and D

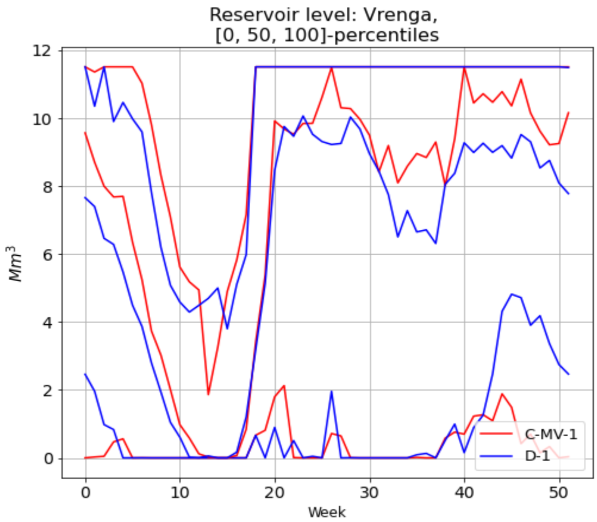

Figure 159: 0-, 50-, 100-percentiles for the reservoir level for Vrenga for scenarios C-MV and D

13.11 Appendix K: Area prices for the different parametrizations

13.11.1 Increased number of scenarios

Scenario A, base

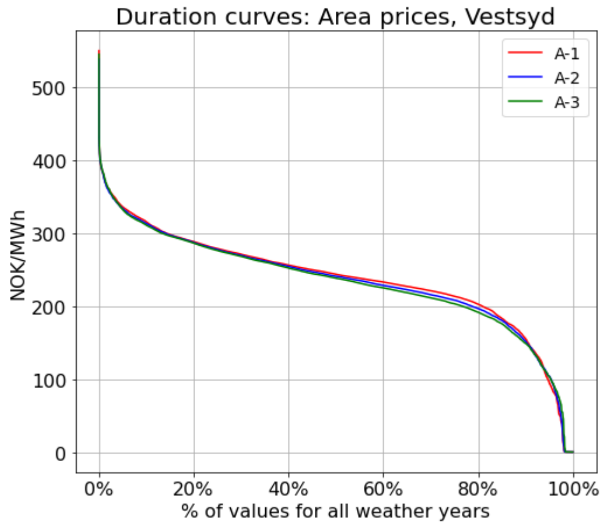

Figure 160: Duration curves for the area prices for Vestsyd when increasing the number of scenarios for A

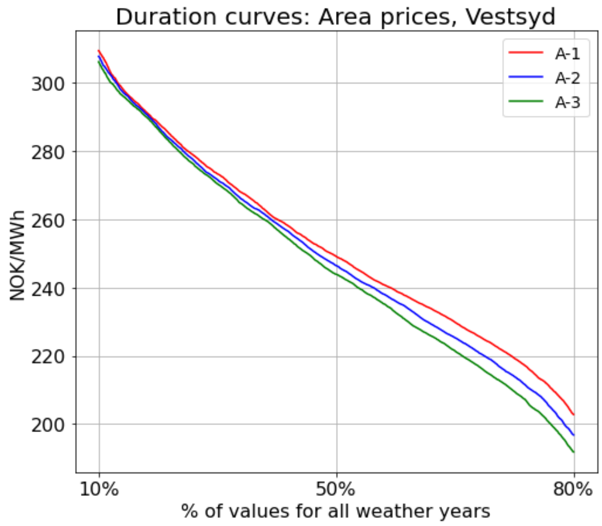

Figure 161: Detailed duration curves for the area prices for Vestsyd when increasing the number of scenarios for A

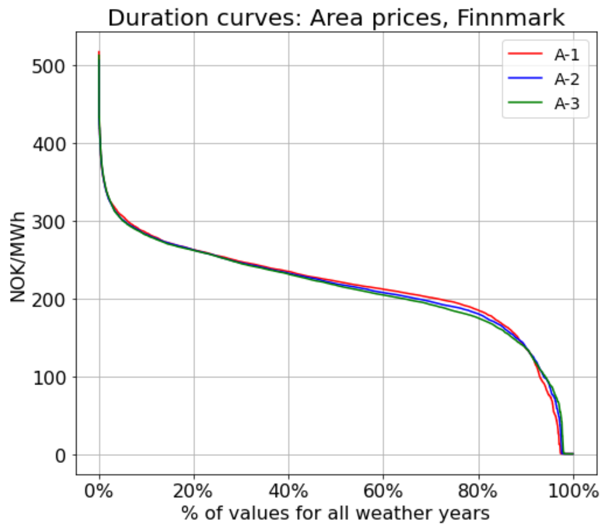

Figure 162: Duration curves for the area prices for Finnmark when increasing the number of scenarios for A

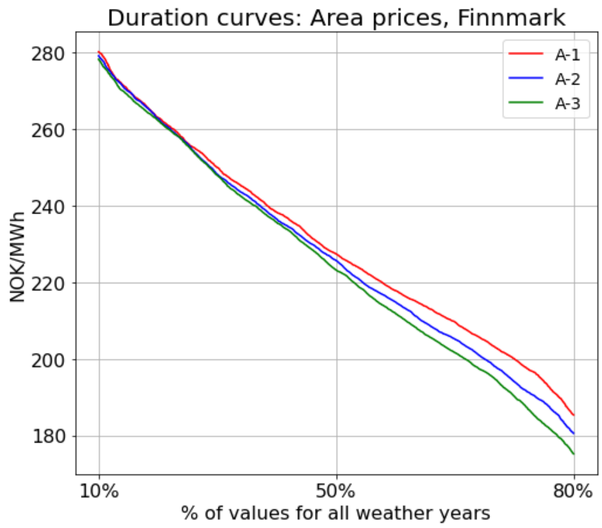

Figure 163: Detailed duration curves for the area prices for Finnmark when increasing the number of scenarios for A

Scenario B, high fuel prices

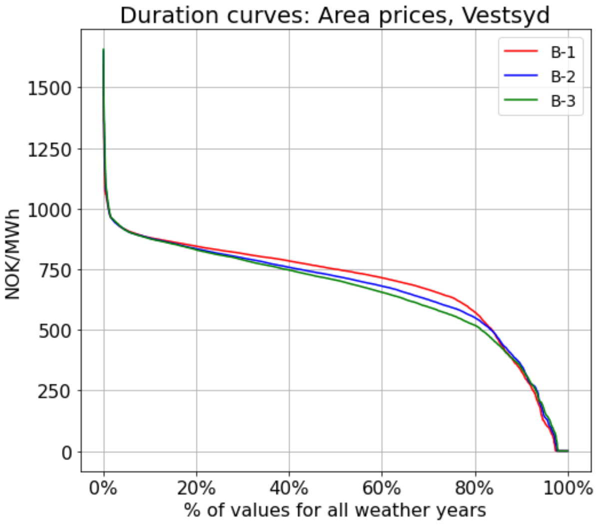

Figure 164: Duration curves for the area prices for Vestsyd when increasing the number of scenarios for B

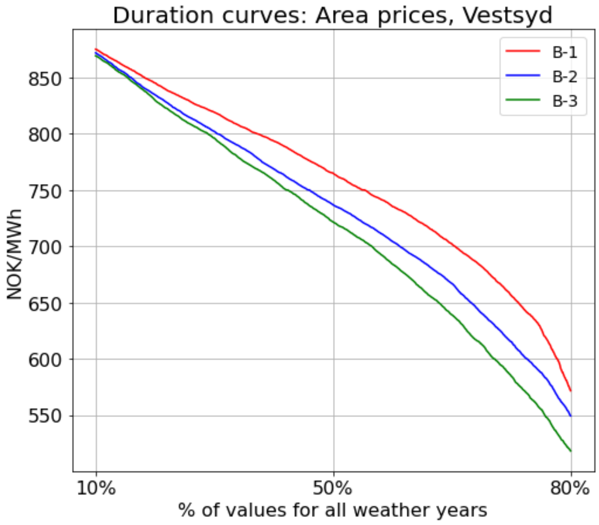

Figure 165: Detailed duration curves for the area prices for Vestsyd when increasing the number of scenarios for B

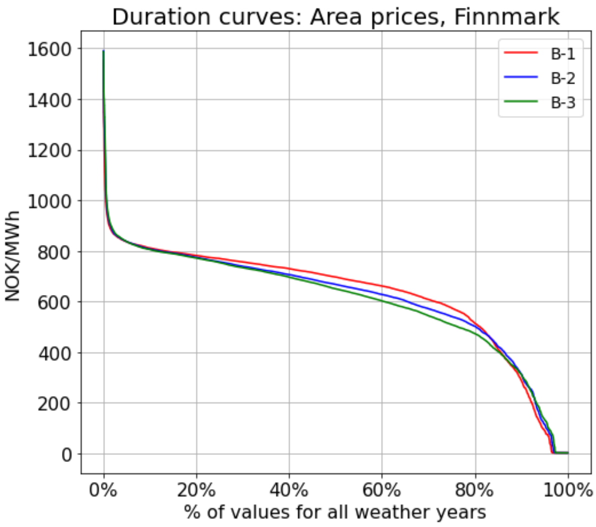

Figure 166: Duration curves for the area prices for Finnmark when increasing the number of scenarios for B

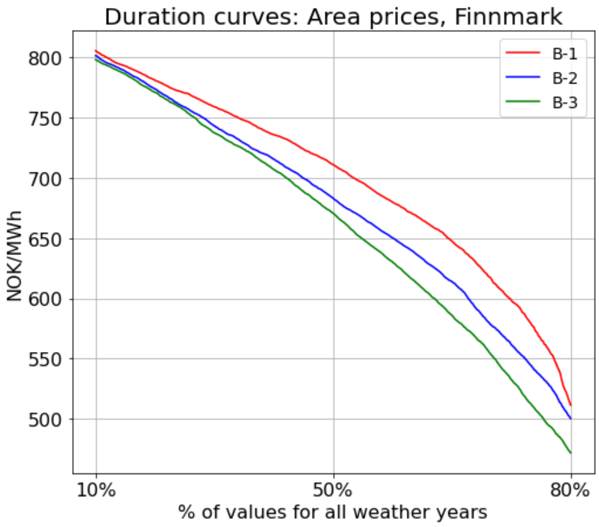

Figure 167: Detailed duration curves for the area prices for Finnmark when increasing the number of scenarios for B

Scenario C-MV, removing subsea cables

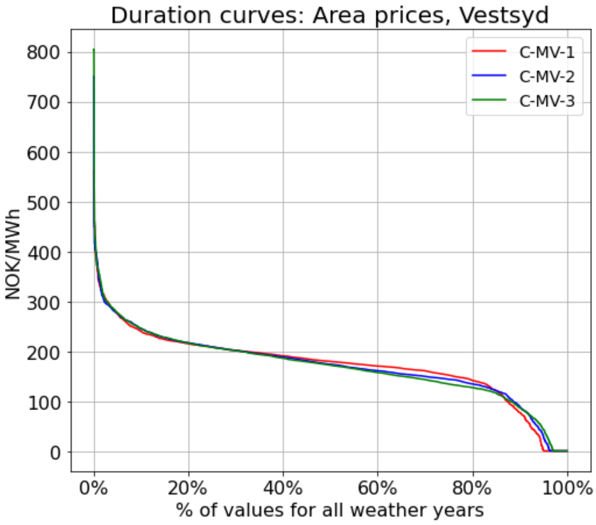

Figure 168: Duration curves for the area prices for Vestsyd when increasing the number of scenarios for C-MV

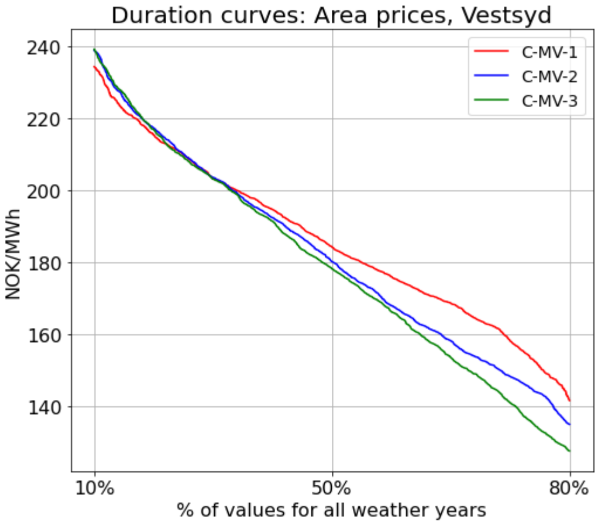

Figure 169: Detailed duration curves for the area prices for Vestsyd when increasing the number of scenarios for C-MV

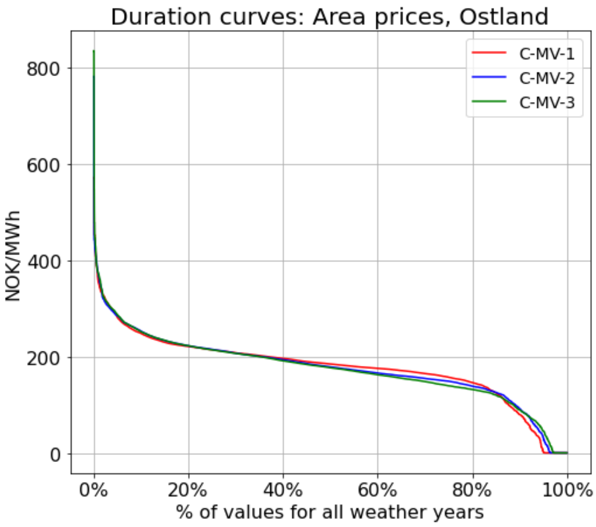

Figure 170: Duration curves for the area prices for Ostland when increasing the number of scenarios for C-MV

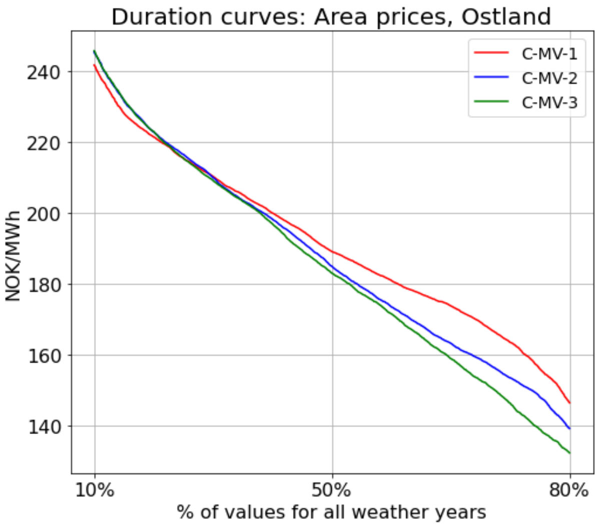

Figure 171: Detailed duration curves for the area prices for Ostland when increasing the number of scenarios for C-MV

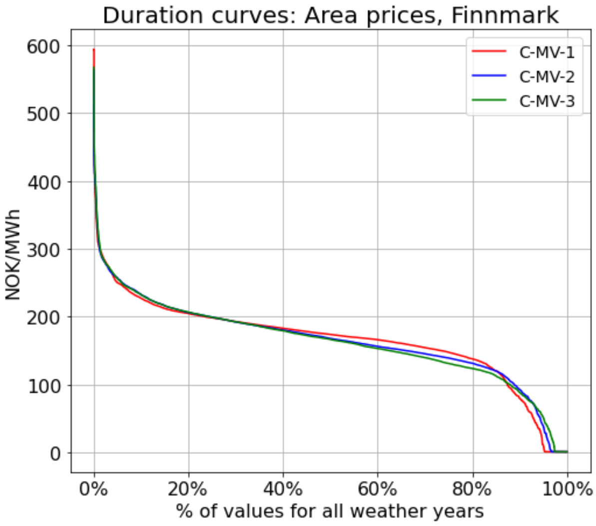

Figure 172: Duration curves for the area prices for Finnmark when increasing the number of scenarios for C-MV

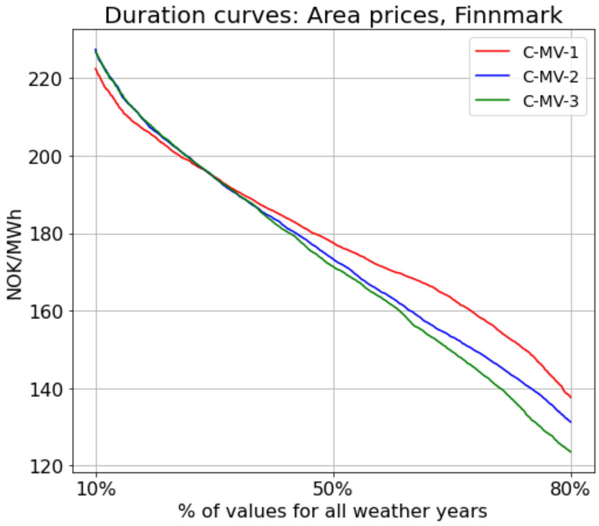

Figure 173: Detailed duration curves for the area prices for Finnmark when increasing the number of scenarios for C-MV

Scenario D, increasing capacity to Great Britain

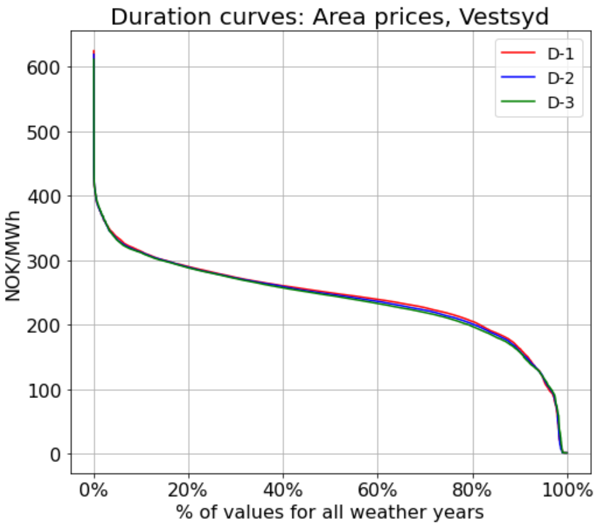

Figure 174: Duration curves for the area prices for Vestsyd when increasing the number of scenarios for D

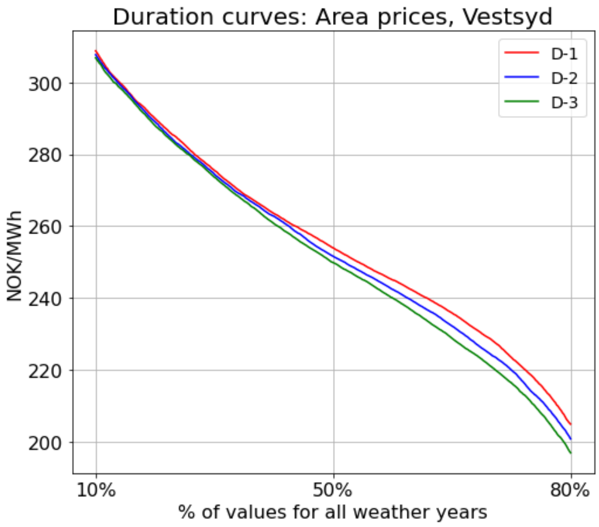

Figure 175: Detailed duration curves for the area prices for Vestsyd when increasing the number of scenarios for D

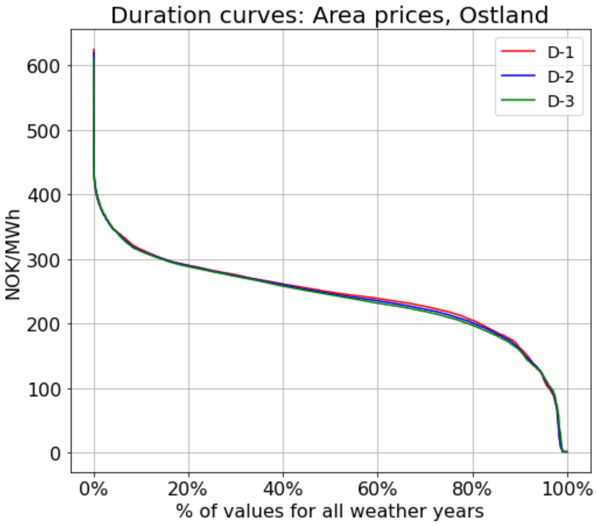

Figure 176: Duration curves for the area prices for Ostland when increasing the number of scenarios for D

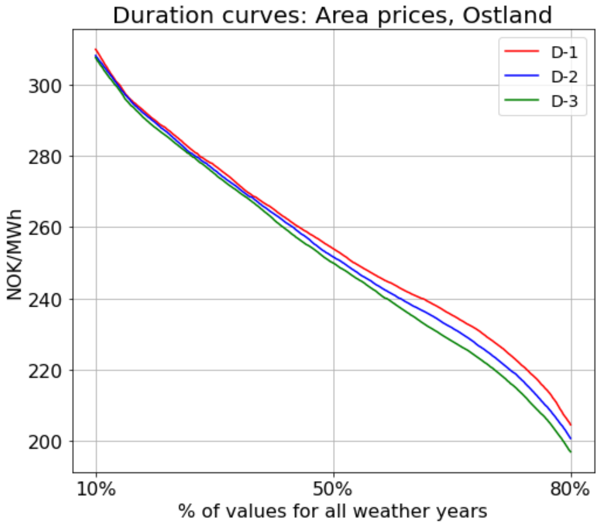

Figure 177: Detailed duration curves for the area prices for Ostland when increasing the number of scenarios for D

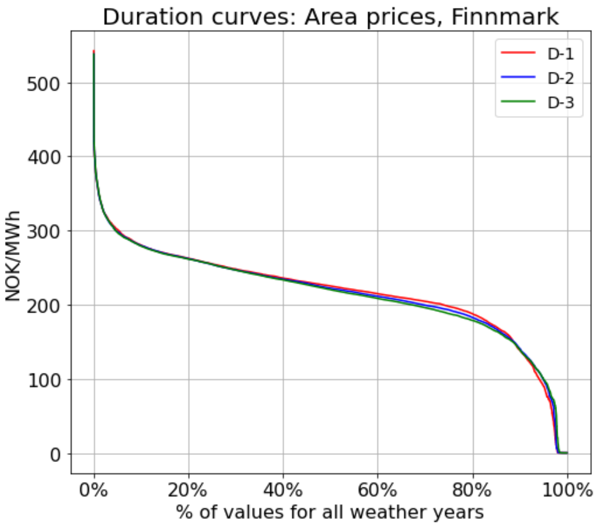

Figure 178: Duration curves for the area prices for Finnmark when increasing the number of scenarios for D

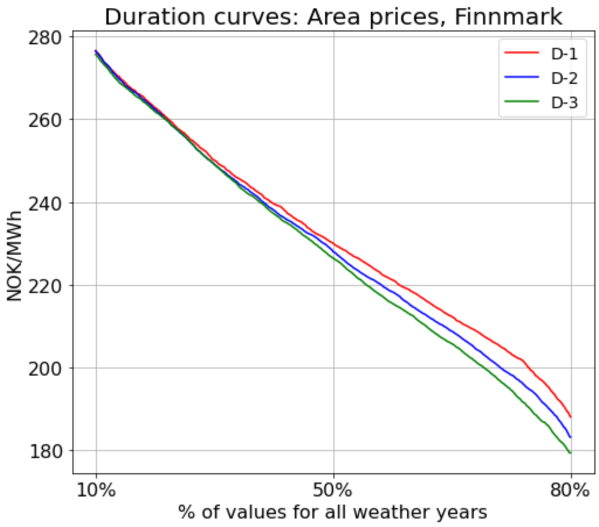

Figure 179: Detailed duration curves for the area prices for Finnmark when increasing the number of scenarios for D

13.11.2 Increased scenario-length

Scenario A, base

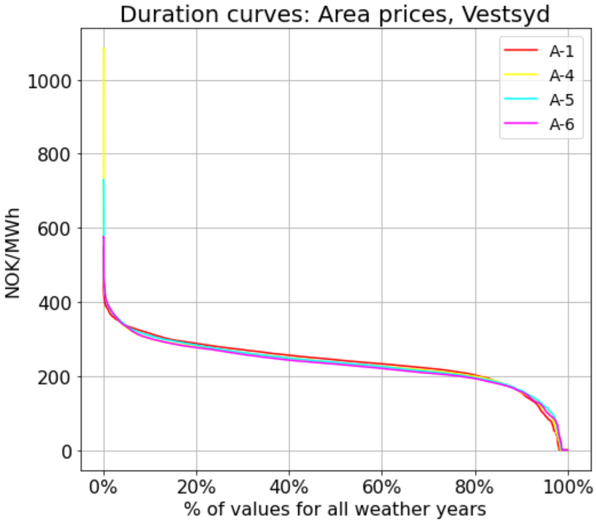

Figure 180: Duration curves for the area prices for Vestsyd when increasing the time horizon for A

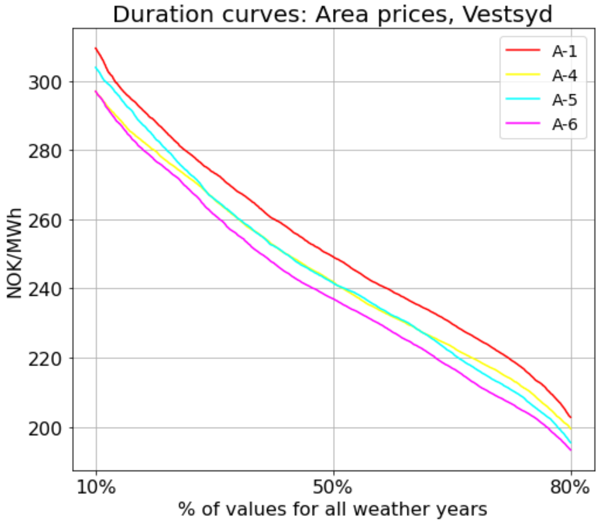

Figure 181: Detailed duration curves for the area prices for Vestsyd when increasing the time horizon for A

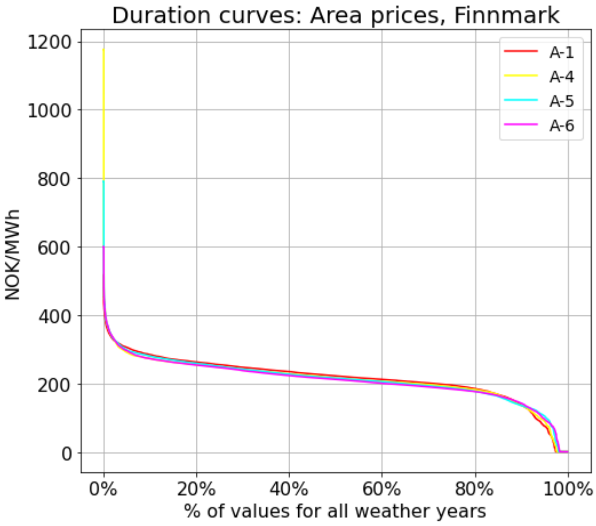

Figure 182: Duration curves for the area prices for Finnmark when increasing the time horizon for A

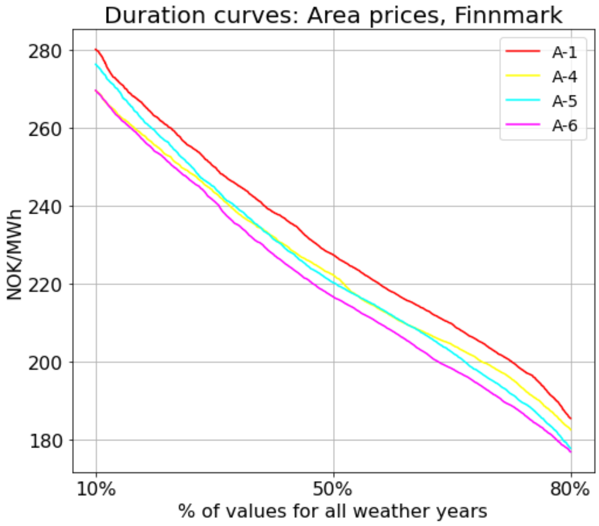

Figure 183: Detailed duration curves for the area prices for Finnmark when increasing the time horizon for A

Scenario B, high fuel prices

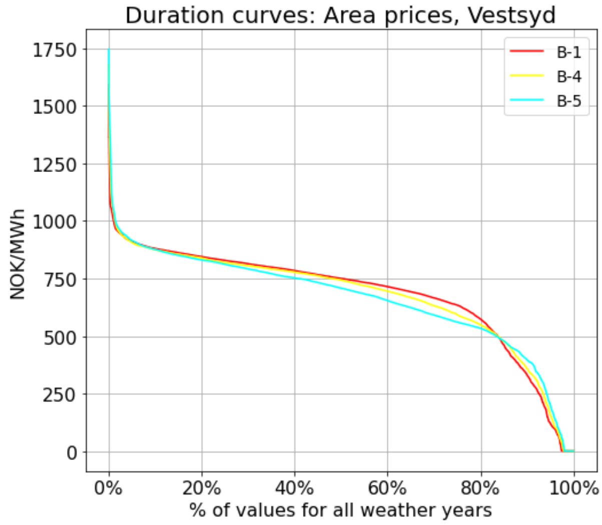

Figure 184: Duration curves for the area prices for Vestsyd when increasing the time horizon for B

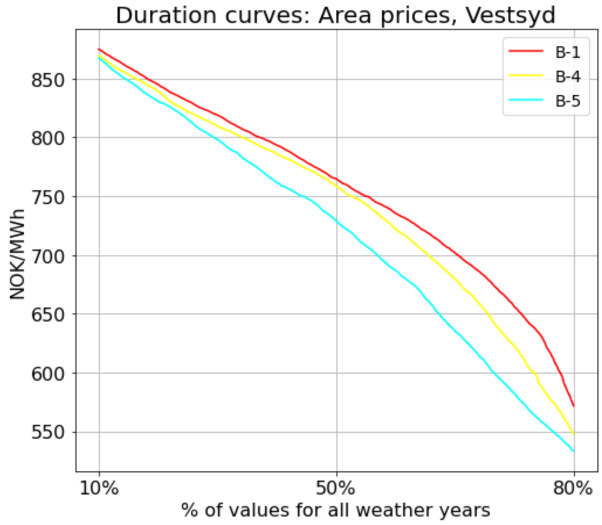

Figure 185: Detailed duration curves for the area prices for Vestsyd when increasing the time horizon for B

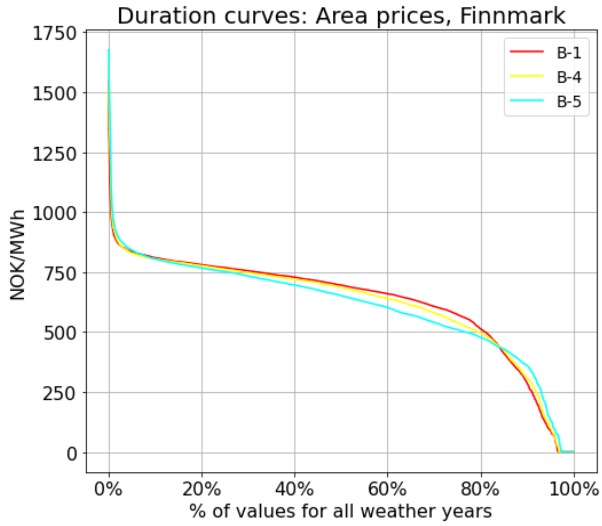

Figure 186: Duration curves for the area prices for Finnmark when increasing the time horizon for B

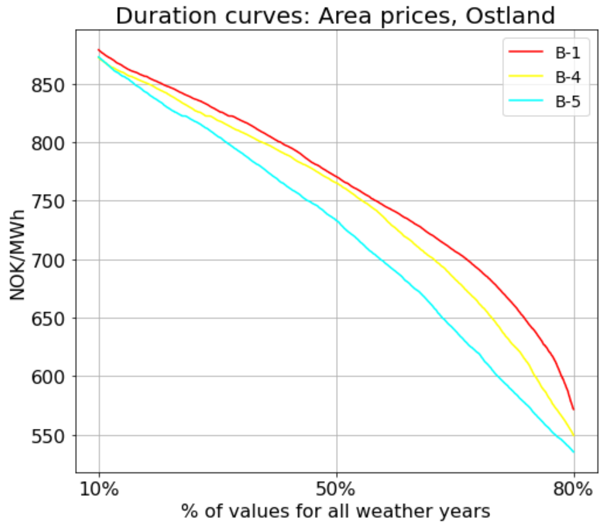

Figure 187: Detailed duration curves for the area prices for Finnmark when increasing the time horizon for B

Scenario C-MV, removing subsea cables

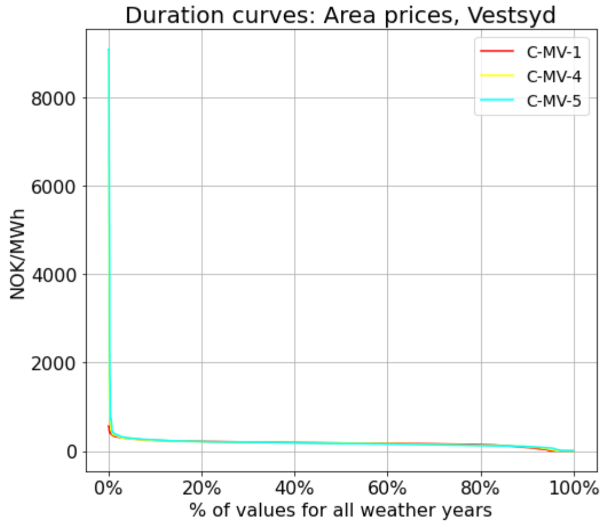

Figure 188: Duration curves for the area prices for Vestsyd when increasing the time horizon for C-MV

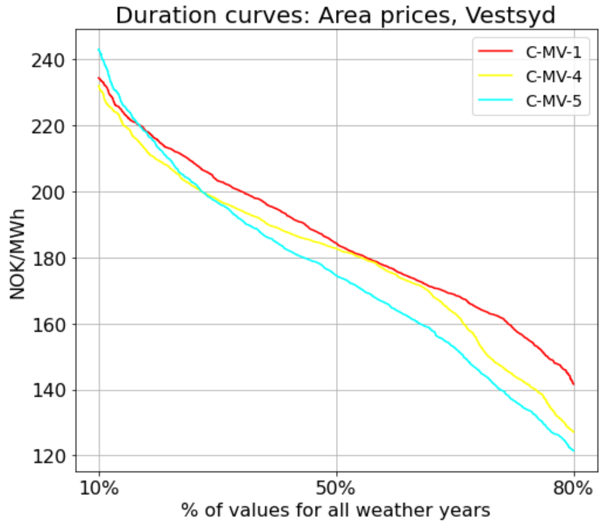

Figure 189: Detailed duration curves for the area prices for Vestsyd when increasing the time horizon for C-MV

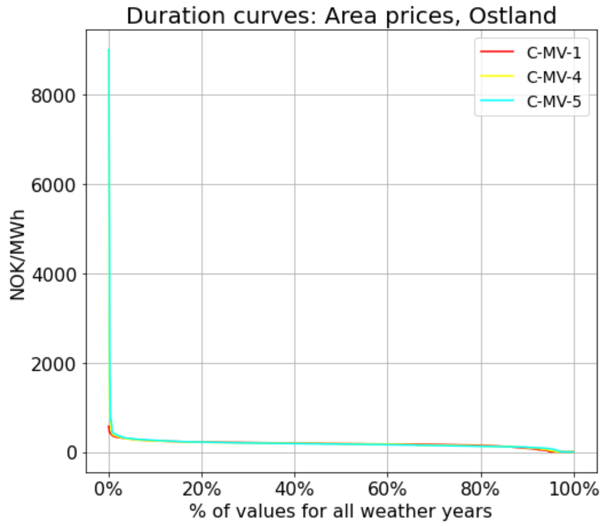

Figure 190: Duration curves for the area prices for Ostland when increasing the time horizon for C-MV

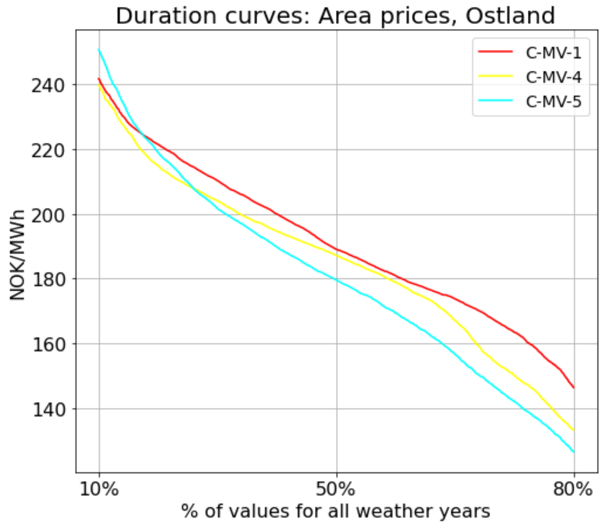

Figure 191: Detailed duration curves for the area prices for Ostland when increasing the time horizon for C-MV

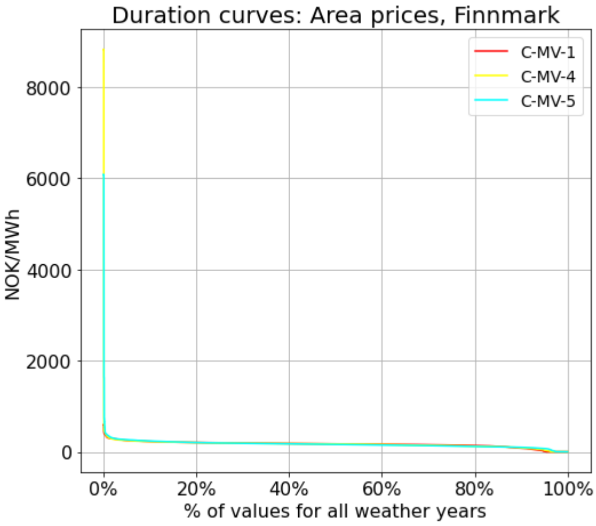

Figure 192: Duration curves for the area prices for Finnmark when increasing the time horizon for C-MV

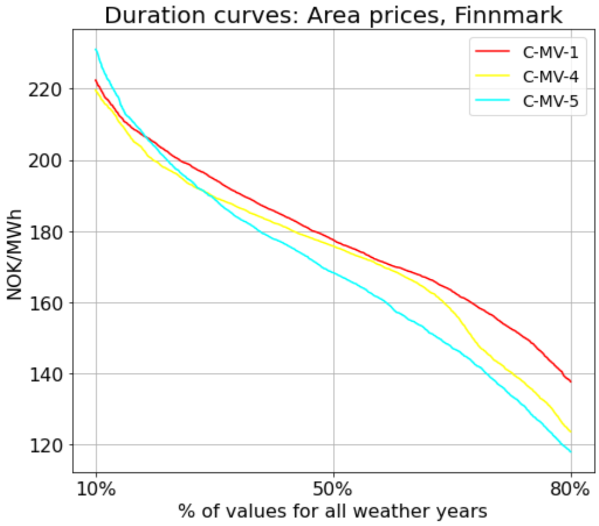

Figure 193: Detailed duration curves for the area prices for Finnmark when increasing the time horizon for C-MV

Scenario D, increasing capacity to Great Britain

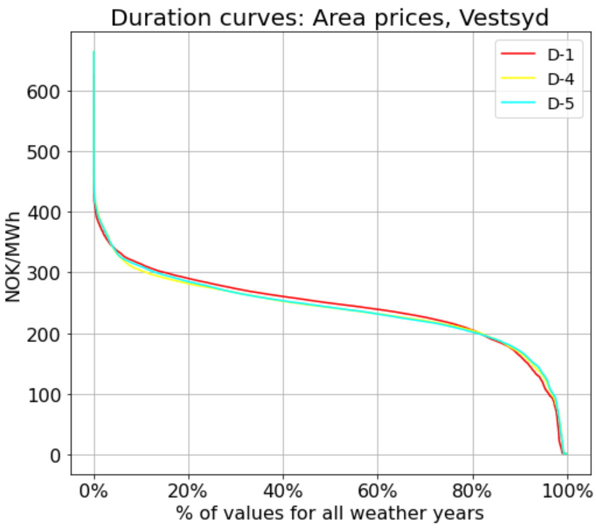

Figure 194: Duration curves for the area prices for Vestsyd when increasing the time horizon for D

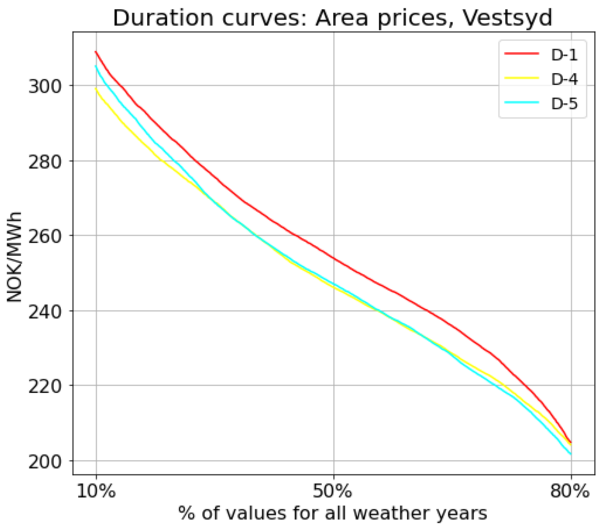

Figure 195: Detailed duration curves for the area prices for Vestsyd when increasing the time horizon for D

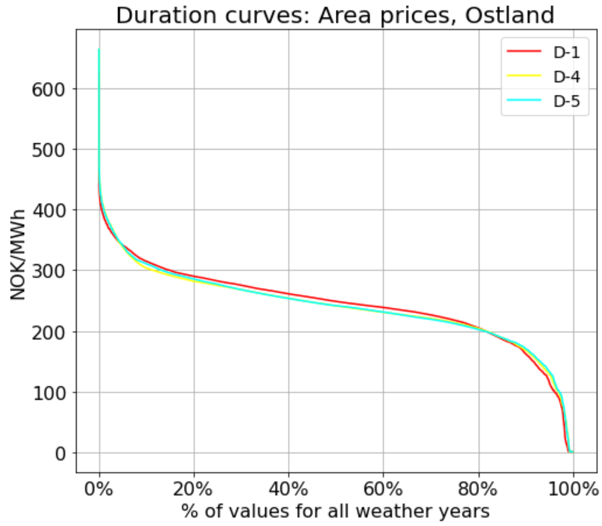

Figure 196: Duration curves for the area prices for Ostland when increasing the time horizon for D

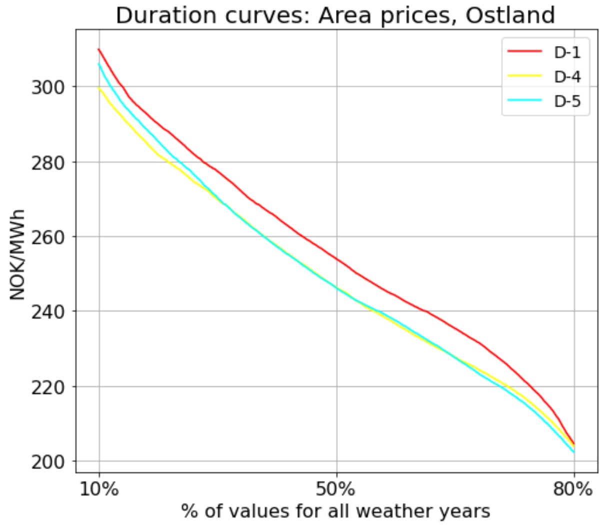

Figure 197: Detailed duration curves for the area prices for Ostland when increasing the time horizon for D

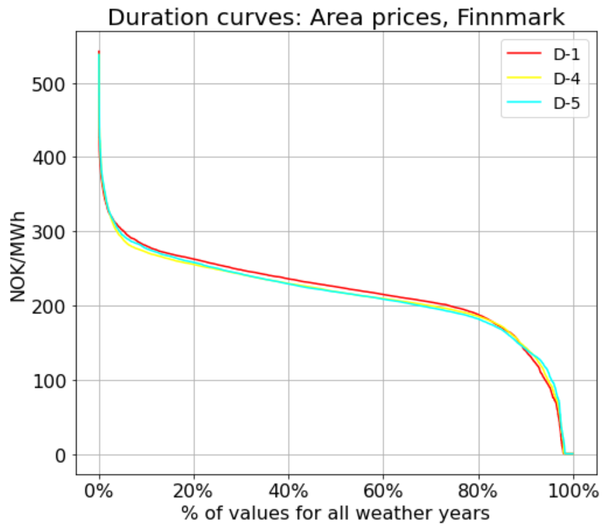

Figure 198: Duration curves for the area prices for Finnmark when increasing the time horizon for D

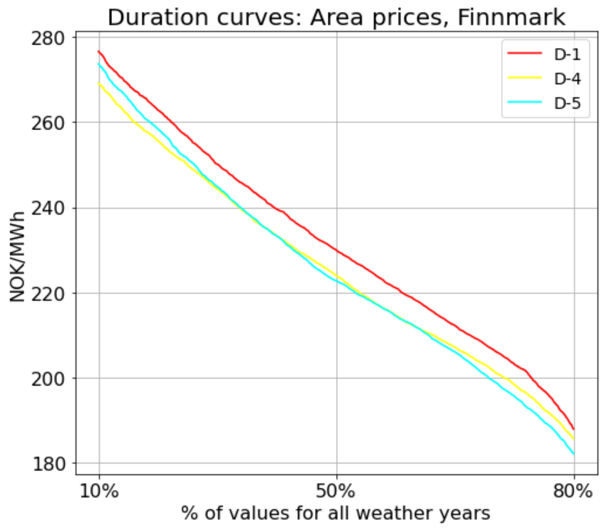

Figure 199: Detailed duration curves for the area prices for Finnmark when increasing the time horizon for D

13.12 Appendix L: Reservoir levels for the different parametrizations

13.12.1 Nore 1

Increased number of scenarios

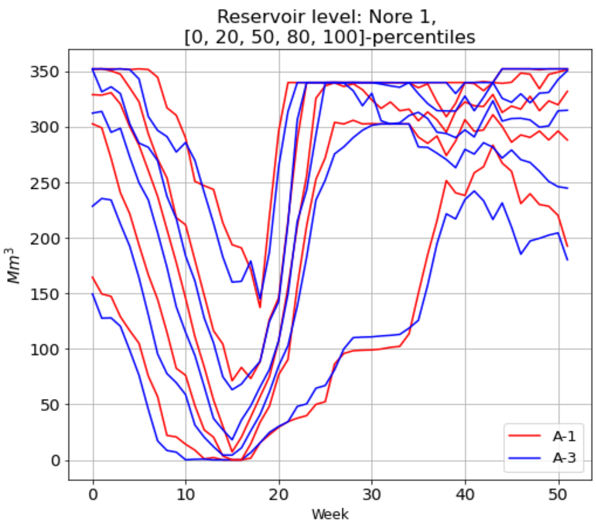

Figure 200: Percentiles for the reservoir level for Nore 1 when increasing the number of scenarios for A

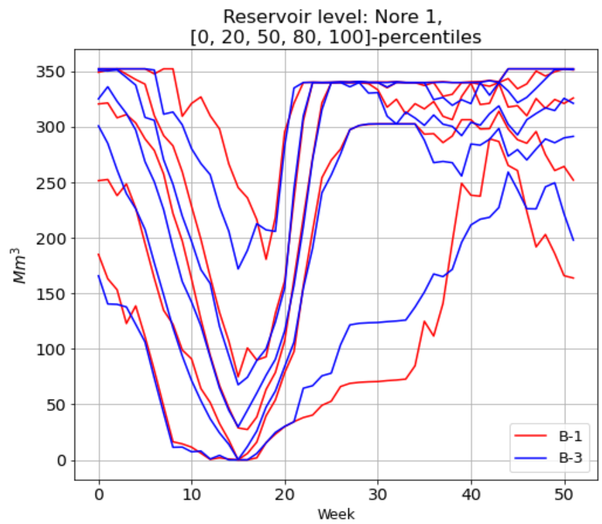

Figure 201: Percentiles for the reservoir level for Nore 1 when increasing the number of scenarios for B

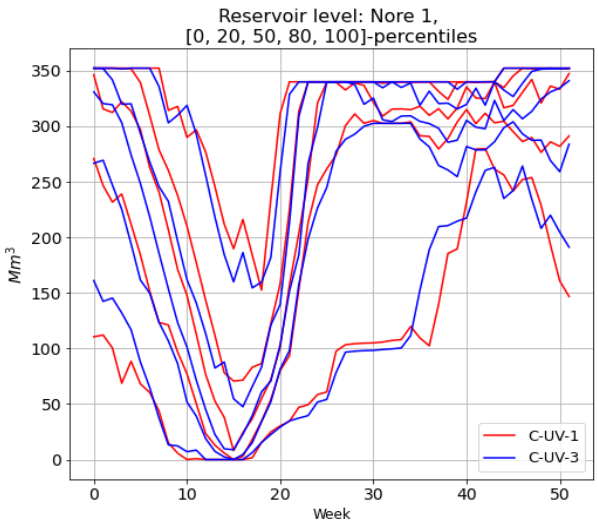

Figure 202: Percentiles for the reservoir level for Nore 1 when increasing the number of scenarios for C-UV

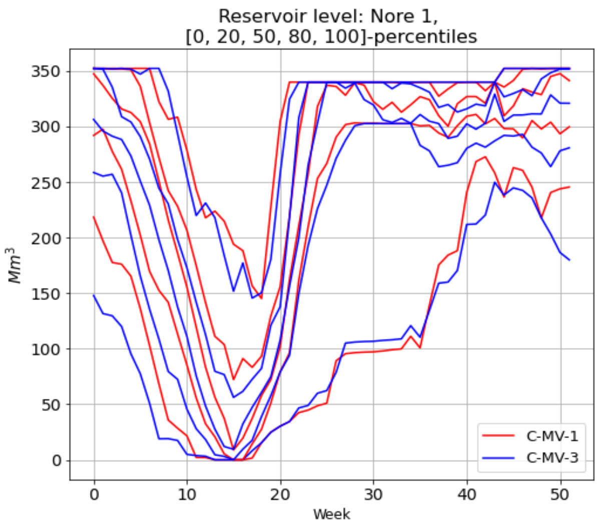

Figure 203: Percentiles for the reservoir level for Nore 1 when increasing the number of scenarios for C-MV

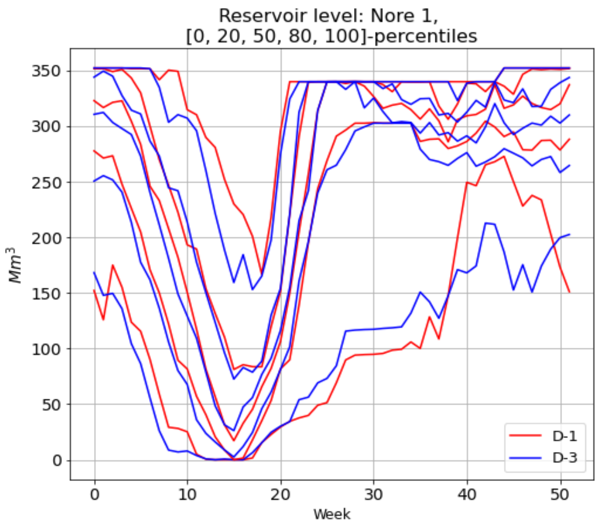

Figure 204: Percentiles for the reservoir level for Nore 1 when increasing the number of scenarios for D

Increased scenario-length

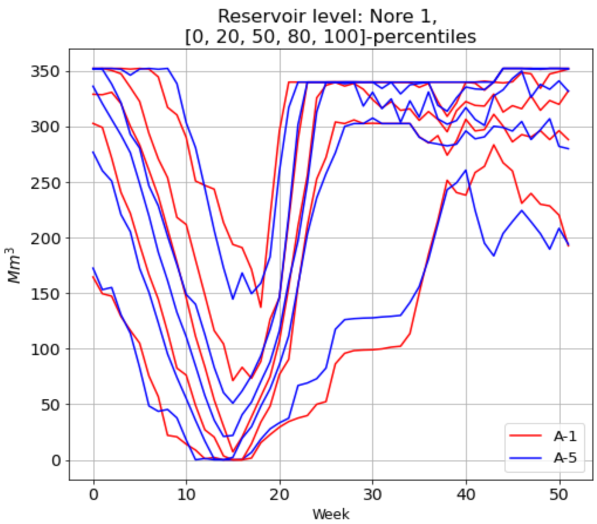

Figure 205: Percentiles for the reservoir level for Nore 1 when increasing the time horizon for A

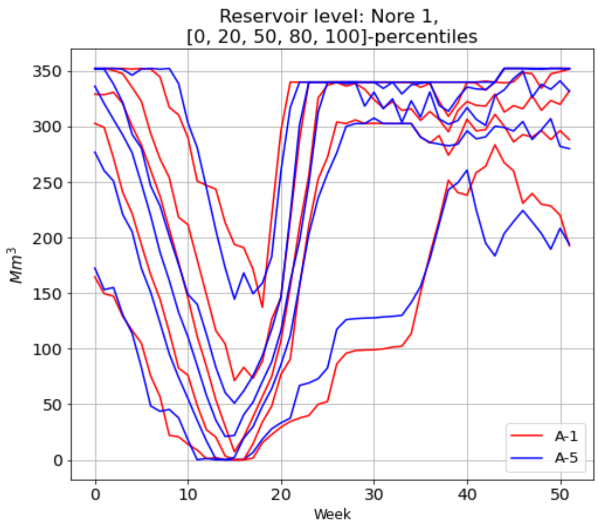

Figure 206: Percentiles for the reservoir level for Nore 1 when increasing the time horizon for B

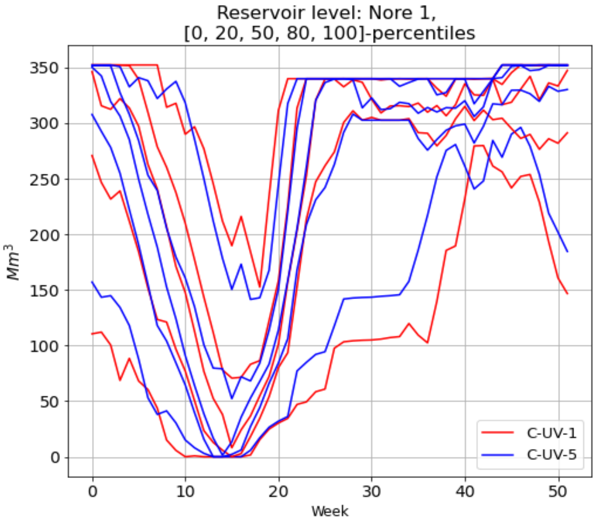

Figure 207: Percentiles for the reservoir level for Nore 1 when increasing the time horizon for C-UV

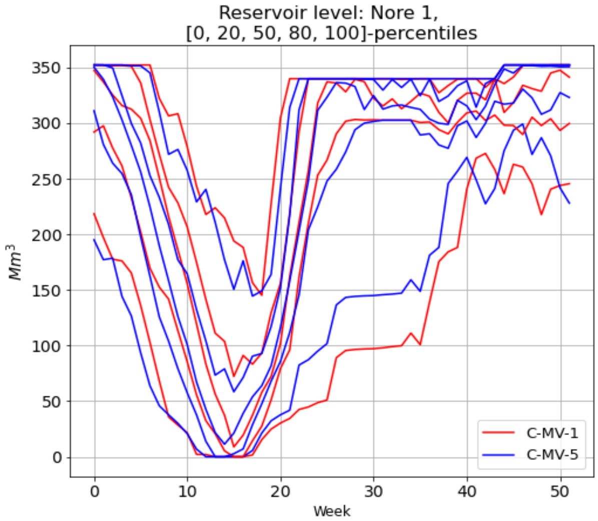

Figure 208: Percentiles for the reservoir level for Nore 1 when increasing the time horizon for C-MV

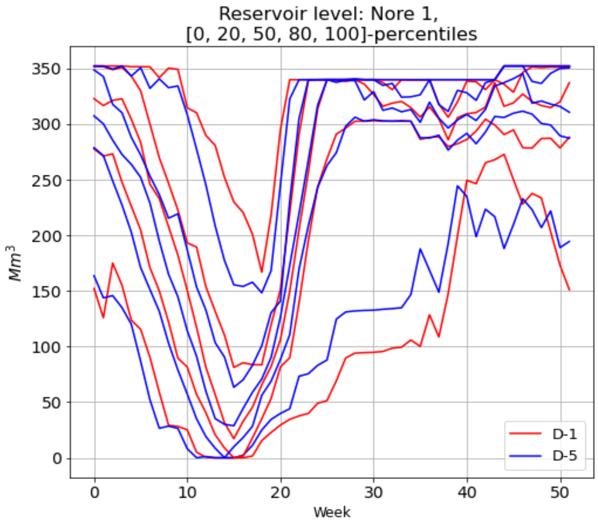

Figure 209: Percentiles for the reservoir level for Nore 1 when increasing the time horizon for D

13.12.2 Vrenga

Increased number of scenarios

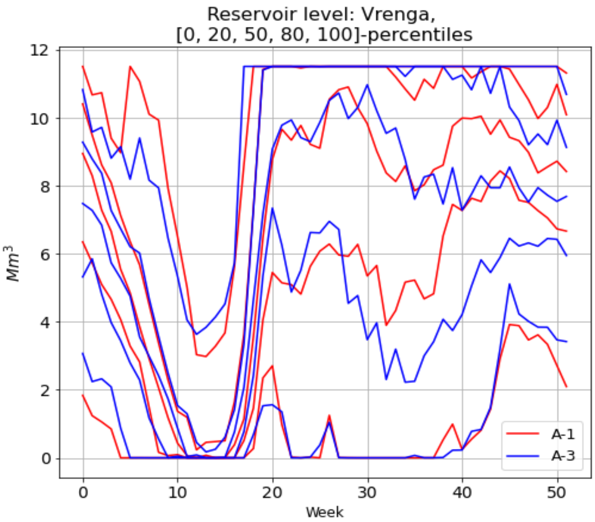

Figure 210: Percentiles for the reservoir level for Vrenga when increasing the number of scenarios for A

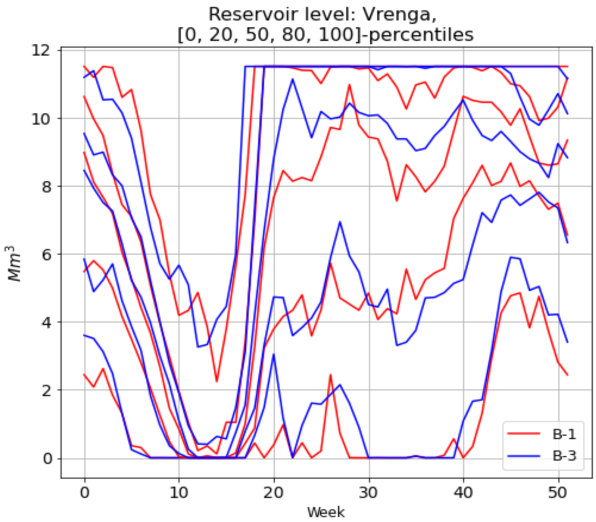

Figure 211: Percentiles for the reservoir level for Vrenga when increasing the number of scenarios for B

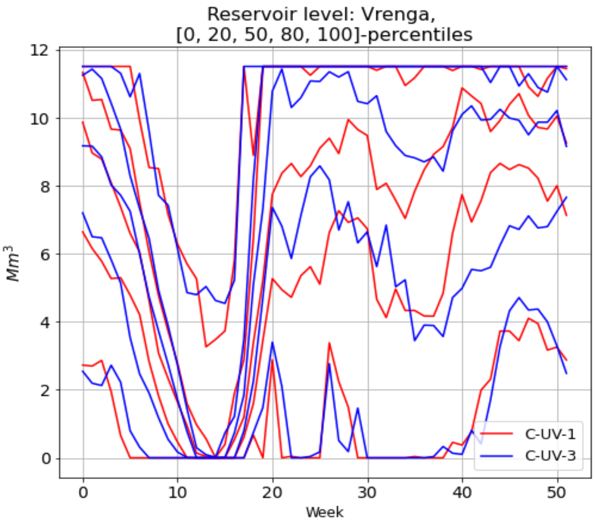

Figure 212: Percentiles for the reservoir level for Vrenga when increasing the number of scenarios for C-UV

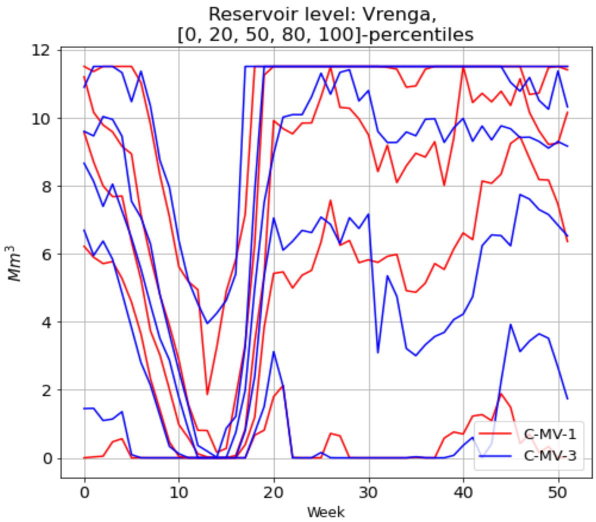

Figure 213: Percentiles for the reservoir level for Vrenga when increasing the number of scenarios for C-MV

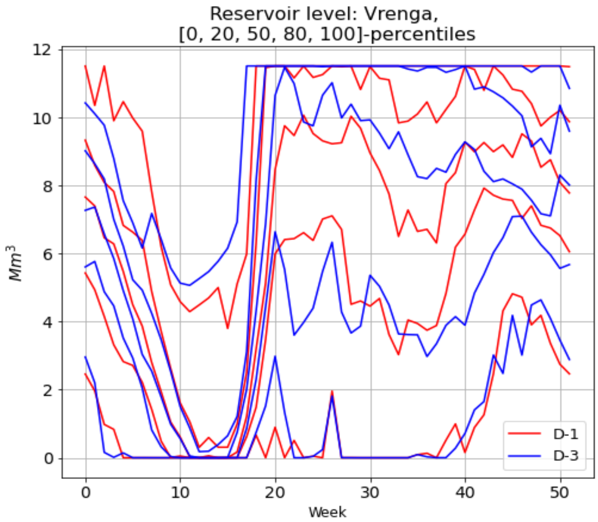

Figure 214: Percentiles for the reservoir level for Vrenga when increasing the number of scenarios for D

Increased scenario-length

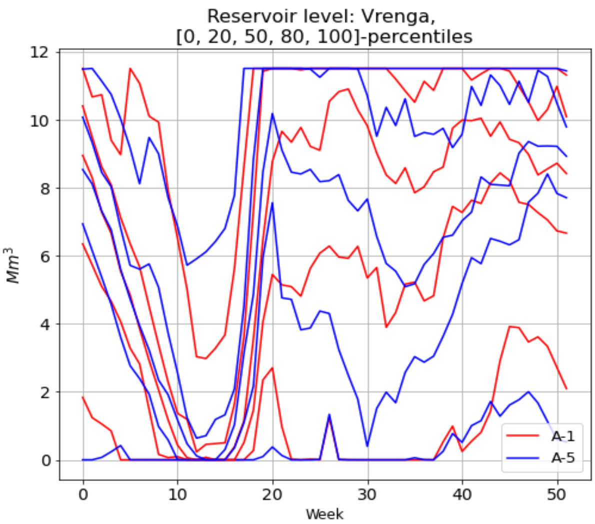

Figure 215: Percentiles for the reservoir level for Vrenga when increasing the time horizon for A

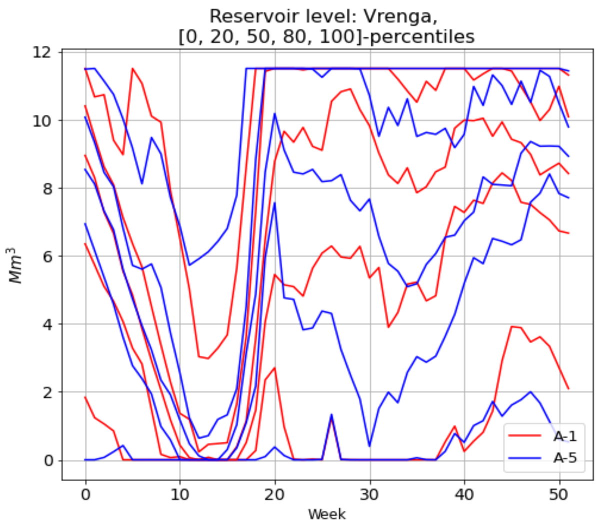

Figure 216: Percentiles for the reservoir level for Vrenga when increasing the time horizon for B

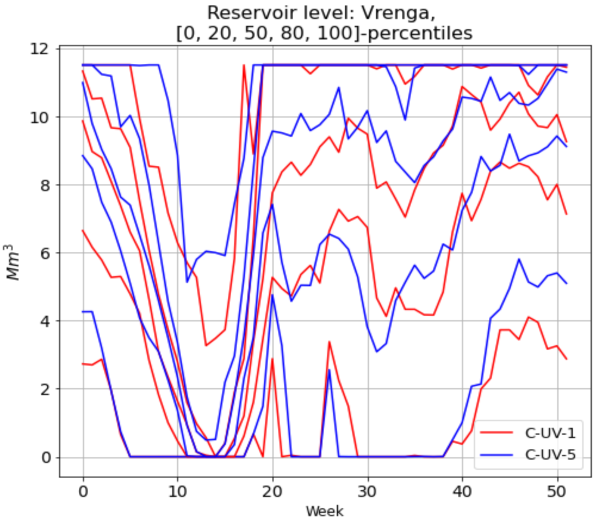

Figure 217: Percentiles for the reservoir level for Vrenga when increasing the time horizon for C-UV

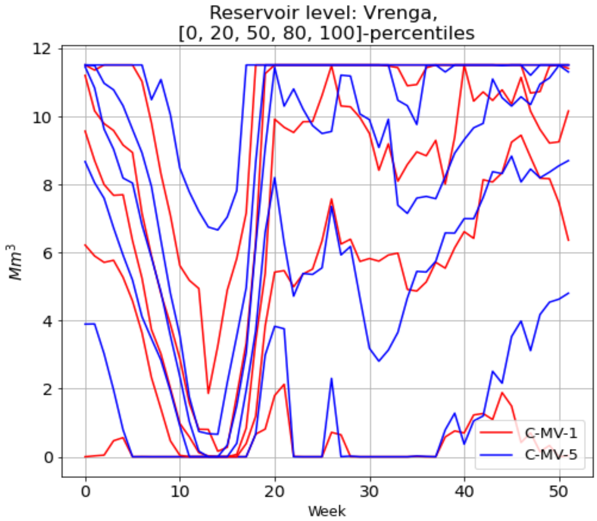

Figure 218: Percentiles for the reservoir level for Vrenga when increasing the time horizon for C-MV

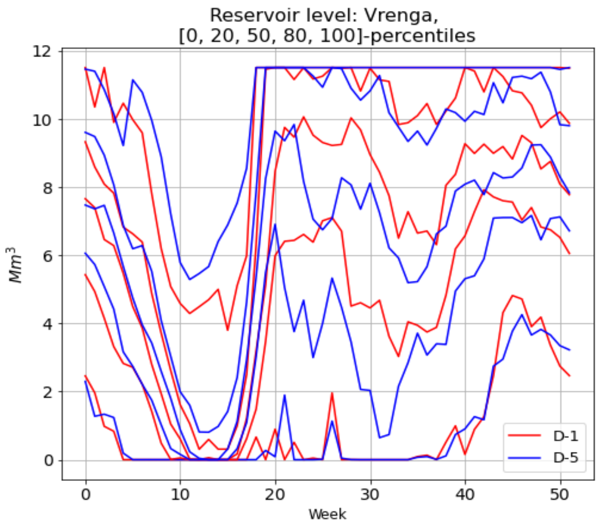

Figure 219: Percentiles for the reservoir level for Vrenga when increasing the time horizon for D

13.13 Appendix M: Model run times

Dataset A: Base

A-1: start at 11:55, 24.01.22, stop at 04.14, 26.01.22. **Total: 40h 19min**
A-2: start at 14:05, 03.02.22, stop at 13.56, 05.02.22. **Total: 47h 51 min**
A-3: start at 15:33, 05.02.22, stop at 00:58, 08.02.22. **Total: 57h 25min**
A-4: start at 08.29, 08.02.22, stop at 20:00, 12.02.22. **Total: 107h 31min**
A-5: start at 15:51, 18.02.22, stop at 09:31, 26.02.22. **Total: 185h 40 min**
A-6: start at 09.46, 26.02.22, stop at 22.23, 04.03.22. **Total: 156h 37min**

Scenario B: High fuel prices

B-1: start at 08:59, 08.03.22, stop at 04:31, 10.03.22. **Total: 43h 32min**
B-2: start at 11:11, 11.03.22 , stop at 17:06, 13.03.22. **Total: 53h 55min**
B-3: start at 17:10, 13.03.22, stop at 17:11, 16.03.22. **Total: 72h 1min**
B-4: start at 08:32, 23.03.22, stop at 17:28, 28.03,22. **Total: 128h 56 min**
B-5: start at 20:10, 16.03.22, stop at 11:34, 26.03.22. **Total: 231h 24min**

Scenario C: Cutting all subsea cables
C-UV:

C-UV-1: start at 14.41, 18.02.22, stop at 07:41, 20.02.22. **Total 41h**
C-UV-2: start at 14.47, 20.02.22, stop at 16.17, 22.02.22. **Total 49h 30min**
C-UV-3: start at 15:07, 18.03.22, stop at 13:46, 21.03.22. **Total 70h 39min**
C-UV-4: start at 09:40, 21.04.22, stop at 07:33, 26.04.22. **Total 117t 53min**
C-UV-5: start at 13:37, 09.04.22, stop at 04:21, 18.04.22. **Total 206h 44min**

C-MV:

C-MV-1: start at 08.39, 26.02.22, stop at 17.57, 28.02.22. **Total 57h 18min**
C-MV-2: start at 15.17, 13.03.22, stop at 12:25, 16.03.22. **Total 69h 8min**
C-MV-3: start at 09:41, 21.04.22, stop at 20:41, 23.04.22. **Total 59h**
C-MV-4: start at 13:12, 09.04.22, stop at 07:02, 14.04.22. **Total 113h 50min**
C-MV-5: start at 16:33, 28.03.22, stop at 02:30, 07.04.22. **Total 225h 57min**

Scenario D: Increasing capacity to Great Britain

D-1: start at 09:07, 08.03.22, stop at 01:54, 10.03.22. **Total 40h 47min**
D-2: start at 11:11, 11.03.22, stop at 14:17, 13.03.22. **Total 51h 6min**
D-3: start at 08:33, 07.04.22, stop at 13:06, 09.04.22. **Total 52h 33min**
D-4: start at 10:54, 29.03.22, stop at 14:18, 03.03.22. **Total 123h 24min**
D-5: start at 13:09, 09.04.22, stop at 21:21, 17.04.22. **Total 200h 12min**

Scenario E: High rationing price

E-1: start at 16:30, 26.03.22, stop at 16:28, 28.03.22. **Total 47h 58min**
E-2: start at 08:07, 18.04.22, stop at 06:59, 20.04.22. **Total 46h 52min**

Dataset G: Norway in a scarcity situation
G -1: start at 14:12, 21.03.22, stop at 08:29, 23.03.22. **Total 42h 17min**
GC-1: start at 20:13, 16.03.22, stop at 13:56, 18.03.22. **Total 41h 43min**
GD-1: start at 01:00, 05.04.22, stop at 14:07, 06.04.22. **Total 37h 7min**
GE-1: start at 14:12, 06.04.22, stop at 06:18, 08.04.22. **Total 40h 6min**

G -2: start at 21:42, 23.04.22, stop at 16:29, 25.04.22. **Total 42h 47min**
GC-2: start at 08:34, 28.04.22, stop at 13:37, 30.04.33. **Total 53h 3min**
GD-2: start at 08:34, 28.04.22, stop at 06:58, 30.04.22. **Total 46h 14min**
GE-2: start at 12:49, 06.05.22, stop at 14:19, 08.05.22. **Total 49h 30min**

Dataset H: Norway in a large surplus situation
H -1: start at 07:04, 30.04.22, stop at 23:31, 01.05.22. **Total 40h 27min**
HC-1: start at 13:41, 30.04.22, stop at 07:39, 02.05.22. **Total 41h 58min**
HD-1: start at 19:31, 01.05.22, stop at 08:58, 03.05.22. **Total 37h 45min**
HE-1: start at 07:30, 02.05.22, stop at 00:58, 04.05.22. **Total 41h 28min**

H -2: start at 08:35, 04.05.22, stop at 10:42, 06.05.22. **Total 50h 7min**
HC-2: start at 14:22, 08.05.22, stop at 18:23, 10.05.22. **Total 52h 1min**
HD-2: start at 07:41, 09.05.22, stop at 04:31, 11.05.22. **Total 44t 50min**
HE-2: start at 18:29, 10.05.22, stop at 19:26, 12.05.22. **Total 48h 57min**

13.14 Appendix N: Area prices for base case for surplus and scarcity situation

13.14.1 Base cases

Sorland

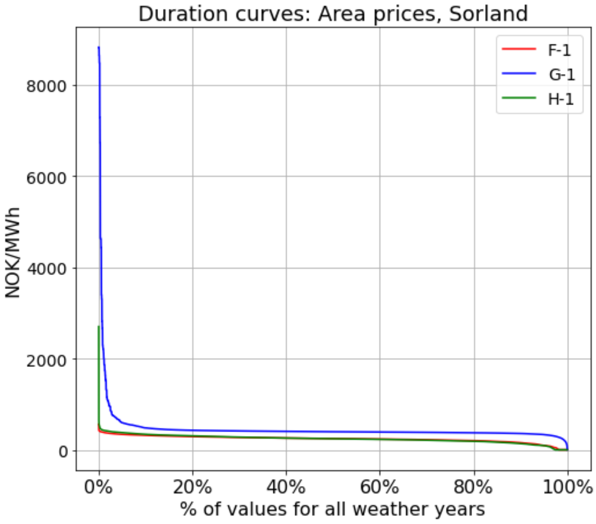

Figure 220: Duration curves for the area prices for Sorland for the base cases

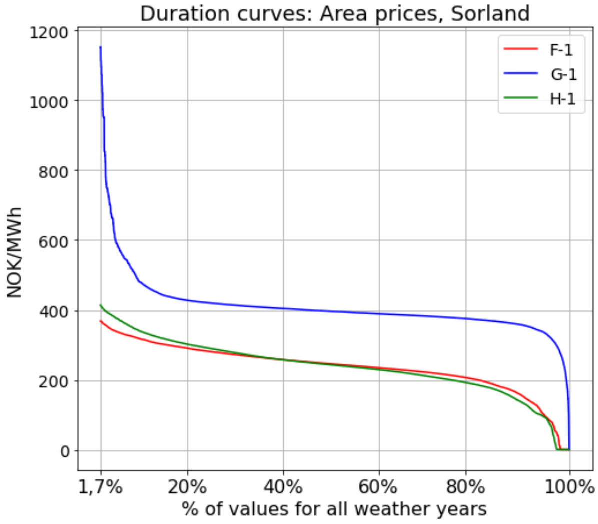

Figure 221: Duration curves for the detailed area prices for Sorland for the base cases

Sorost

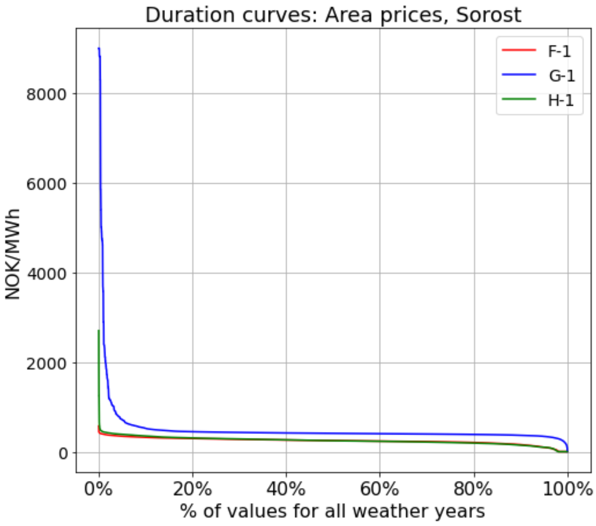

Figure 222: Duration curves for the area prices for Sorost for the base cases

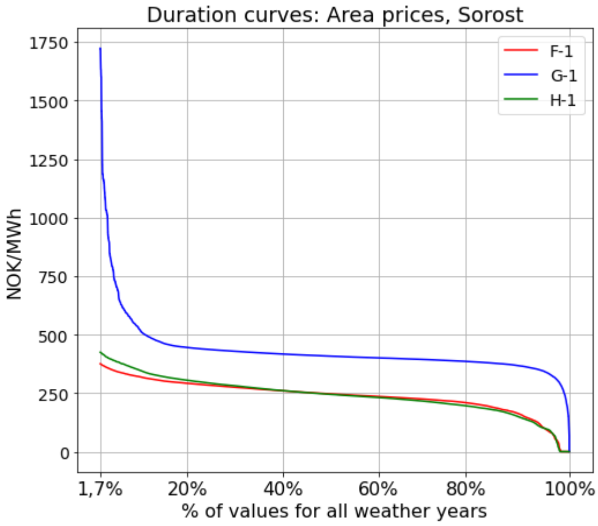

Figure 223: Duration curves for the detailed area prices for Sorost for the base cases

Finnmark

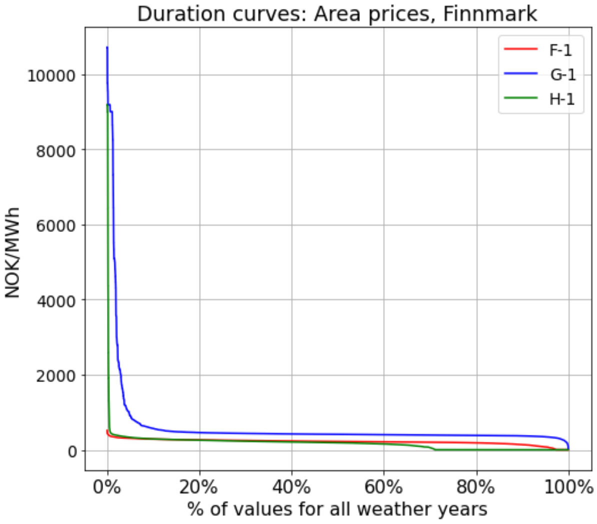

Figure 224: Duration curves for the area prices for Finnmark for the base cases

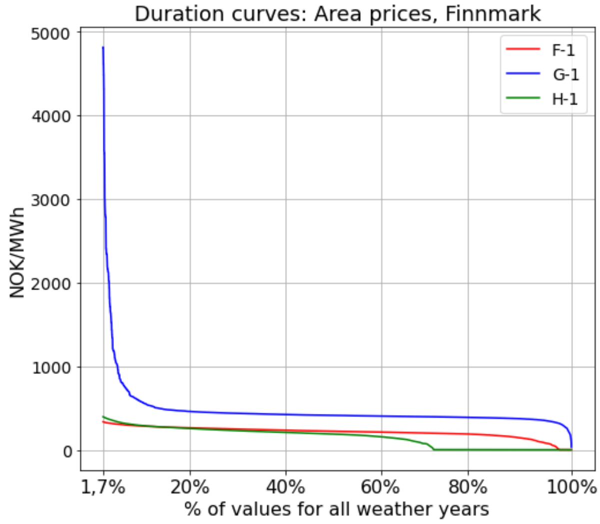

Figure 225: Duration curves for the detailed area prices for Finnmark for the base cases

13.14.2 Dataset F

Sorland

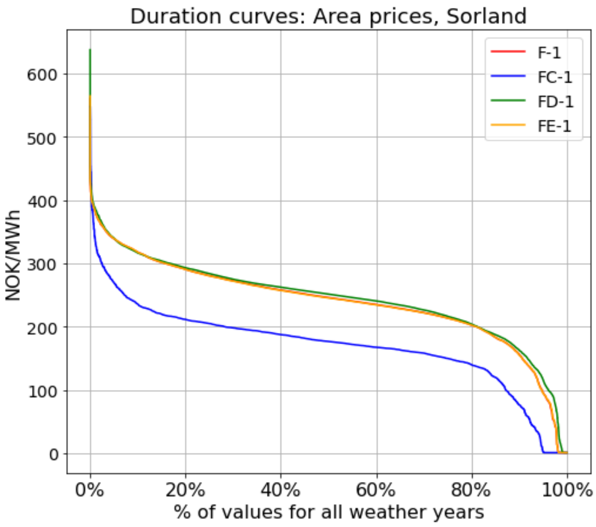

Figure 226: Duration curves for the area prices for Sorland for dataset F

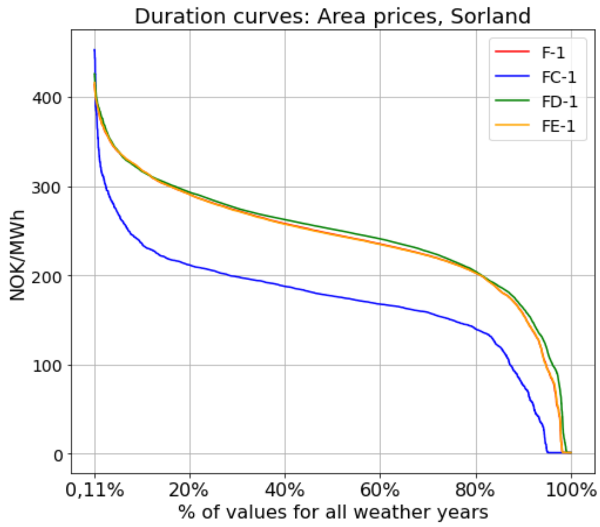

Figure 227: Duration curves for the detailed area prices for Sorland for dataset F

Sorost

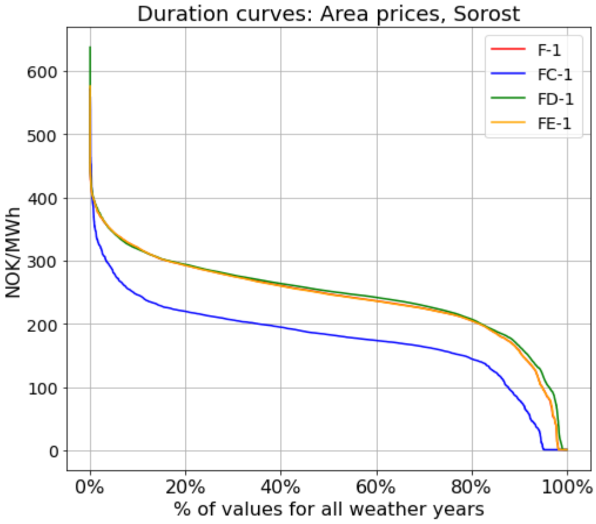

Figure 228: Duration curves for the area prices for Sorost for dataset F

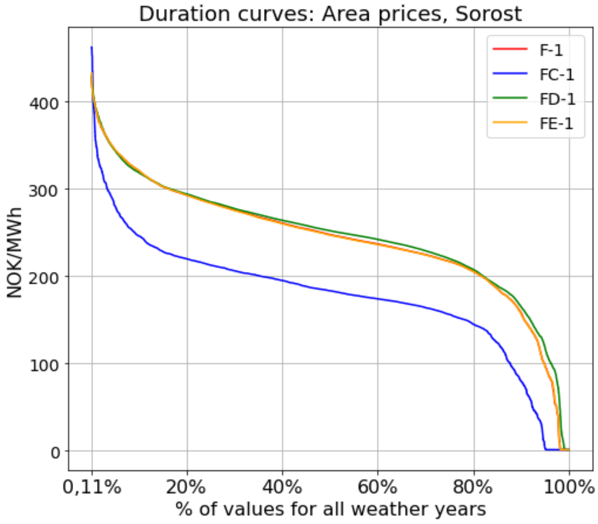

Figure 229: Duration curves for the detailed area prices for Sorost for dataset F

Norgemidt

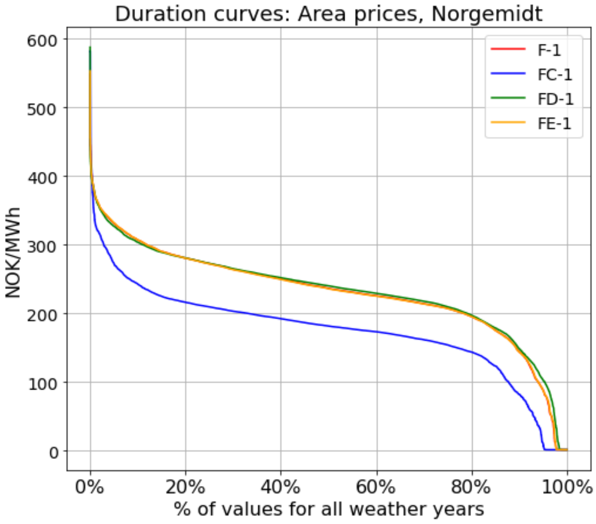

Figure 230: Duration curves for the area prices for Norgemidt for dataset F

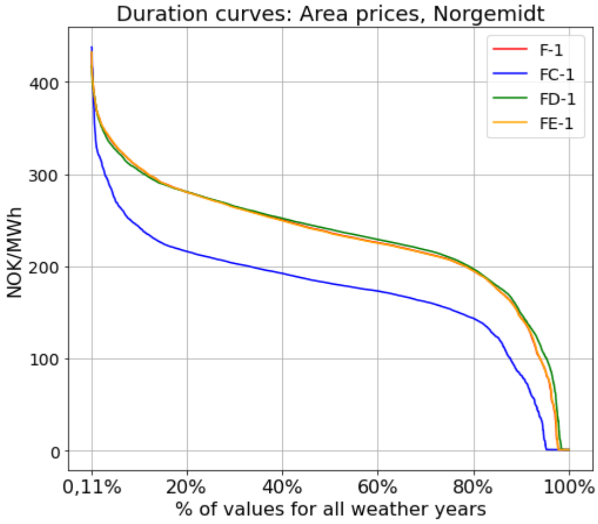

Figure 231: Duration curves for the detailed area prices for Norgemidt for dataset F

Finnmark

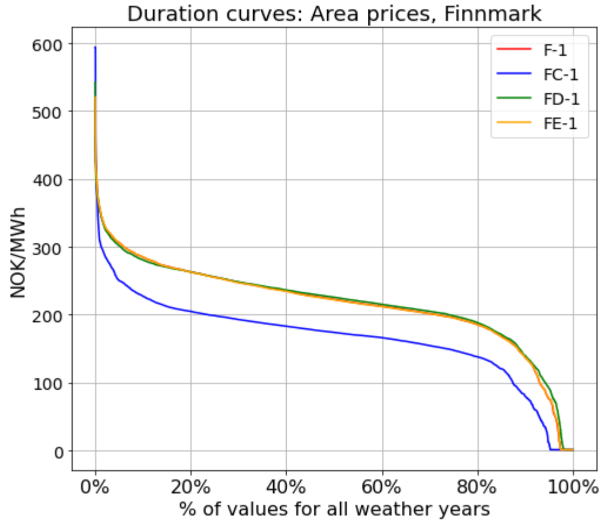

Figure 232: Duration curves for the area prices for Finnmark for dataset F

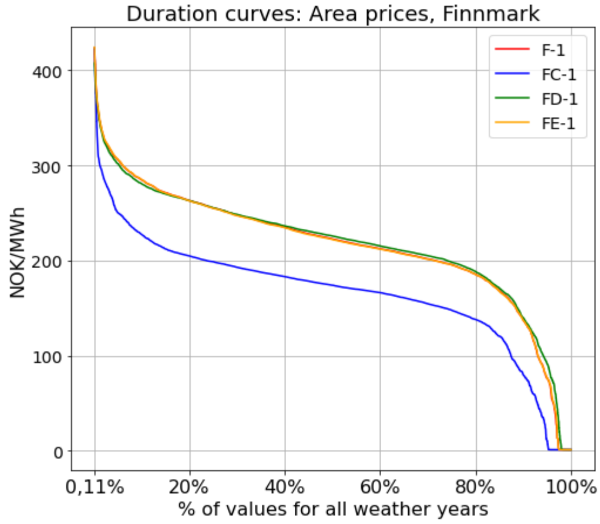

Figure 233: Duration curves for the detailed area prices for Finnmark for dataset F

13.14.3 Dataset G

Sorland

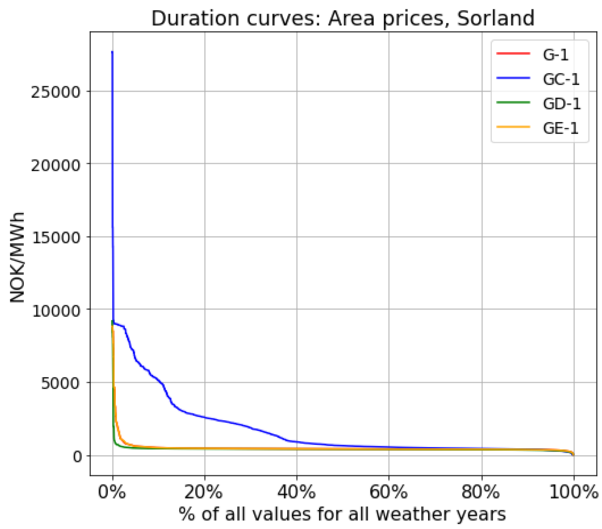

Figure 234: Duration curves for the area prices for Sorland for dataset G

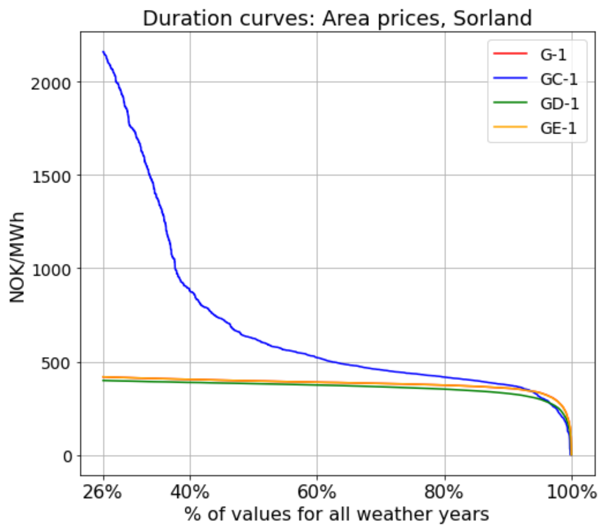

Figure 235: Duration curves for the detailed area prices for Sorland for dataset G

Sorost

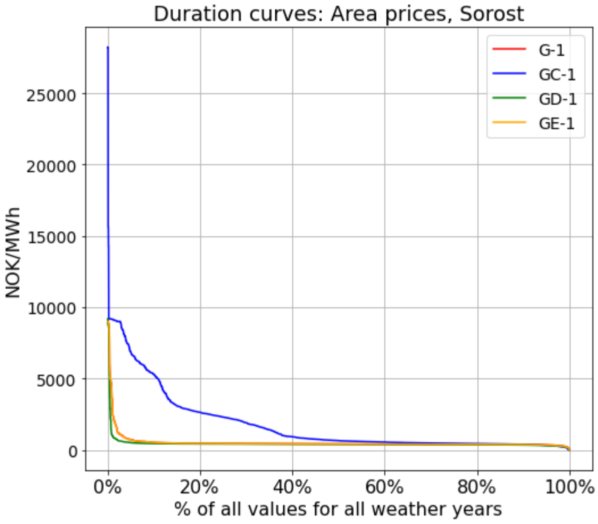

Figure 236: Duration curves for the area prices for Sorost for dataset G

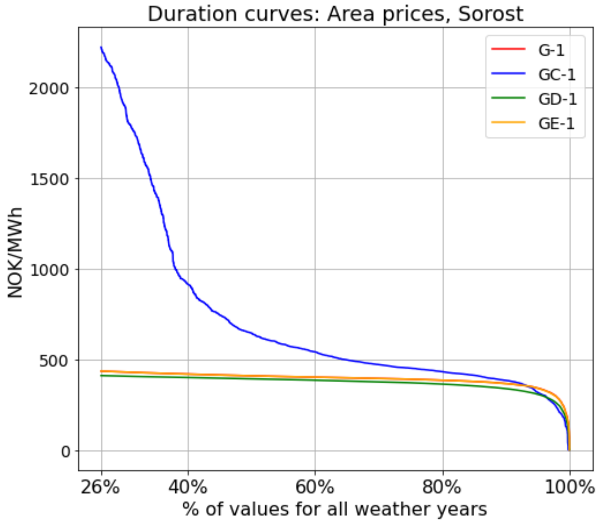

Figure 237: Duration curves for the detailed area prices for Sorost for dataset G

Norgemidt

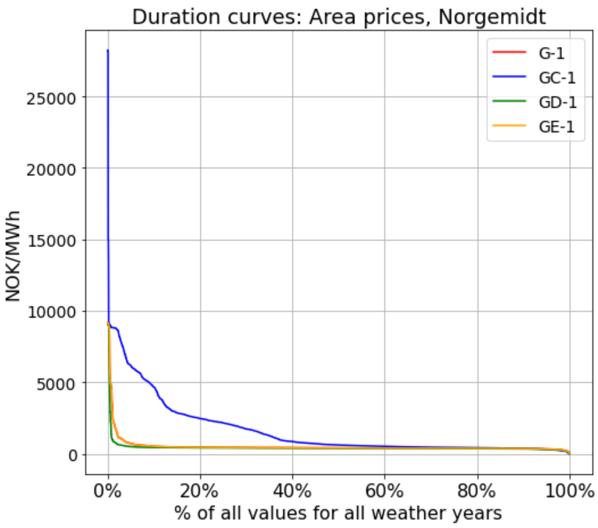

Figure 238: Duration curves for the area prices for Norgemidt for dataset G

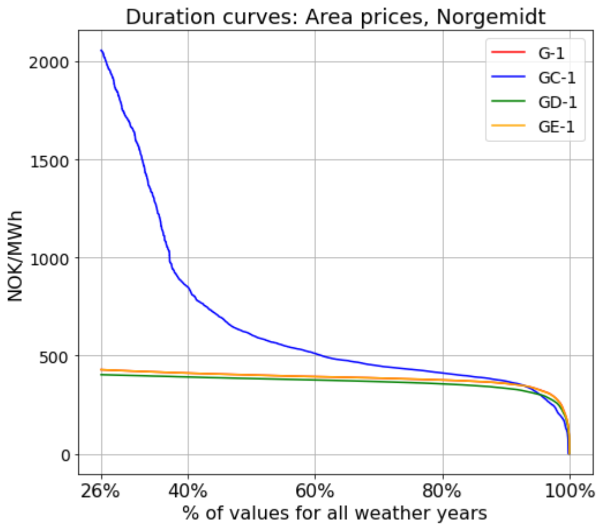

Figure 239: Duration curves for the detailed area prices for Norgemidt for dataset G

Finnmark

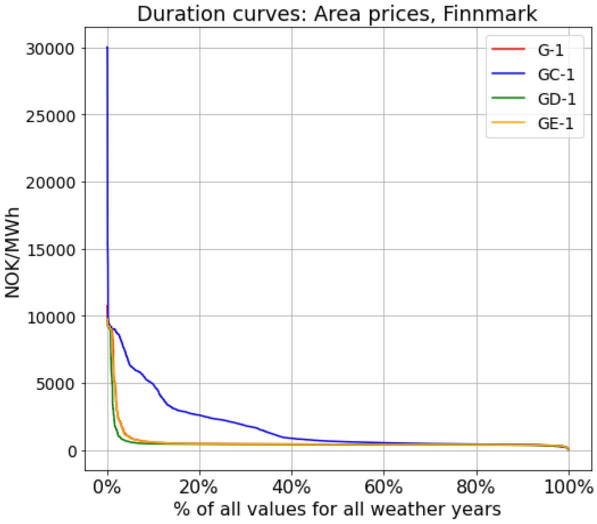

Figure 240: Duration curves for the area prices for Finnmark for dataset G

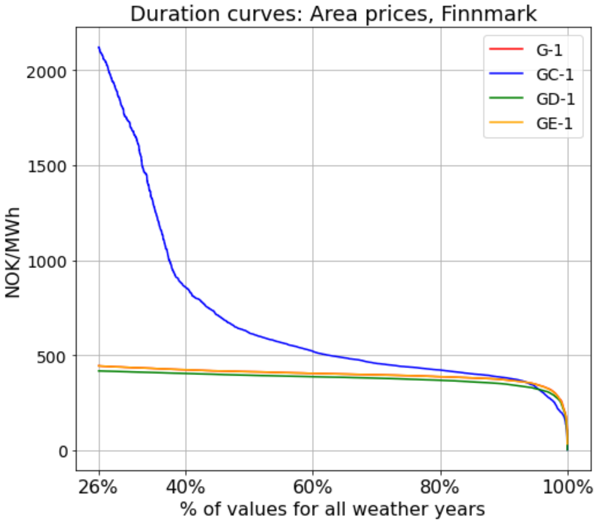

Figure 241: Duration curves for the detailed area prices for Finnmark for dataset G

13.14.4 Dataset H

Sorland

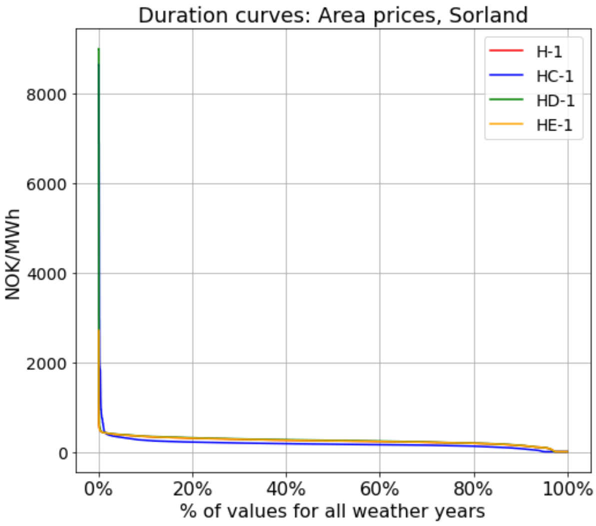

Figure 242: Duration curves for the area prices for Sorland for dataset H

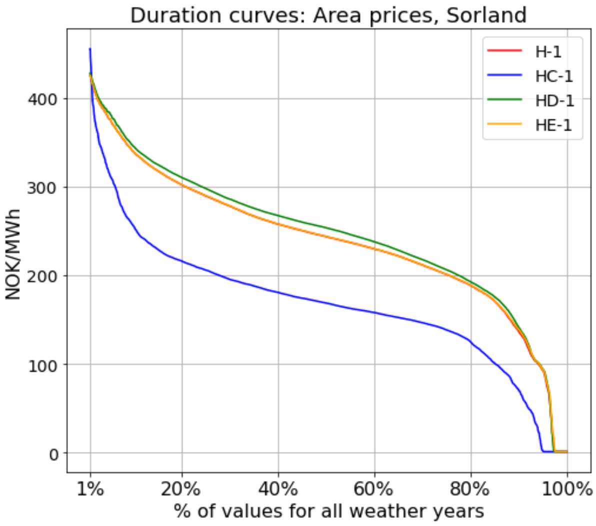

Figure 243: Duration curves for the detailed area prices for Sorland for dataset H

Sorost

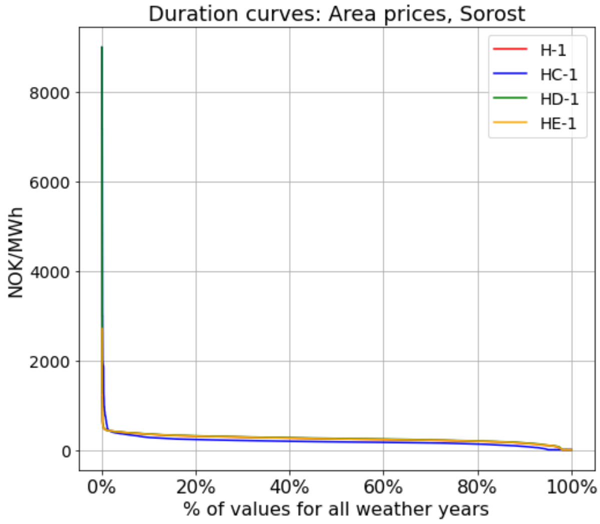

Figure 244: Duration curves for the area prices for Sorost for dataset H

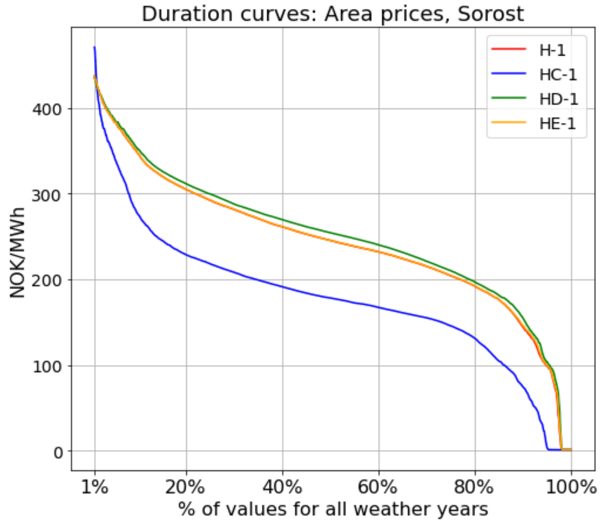

Figure 245: Duration curves for the detailed area prices for Sorost for dataset H

Norgemidt

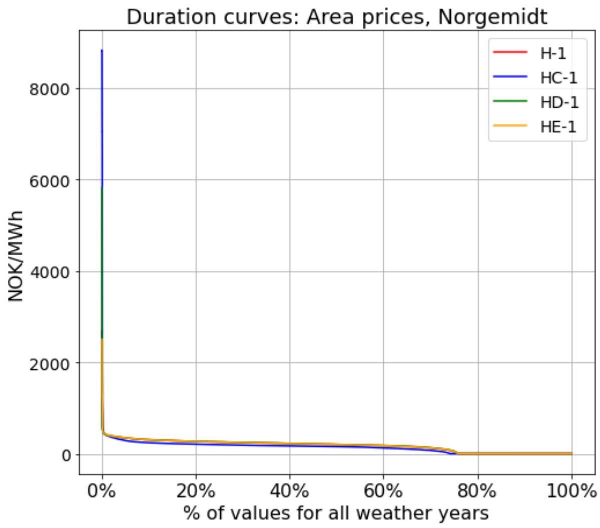

Figure 246: Duration curves for the area prices for Norgemidt for dataset H

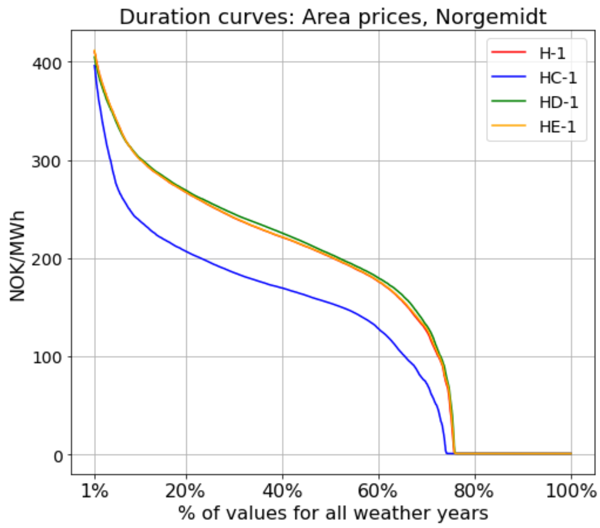

Figure 247: Duration curves for the detailed area prices for Norgemidt for dataset H

Finnmark

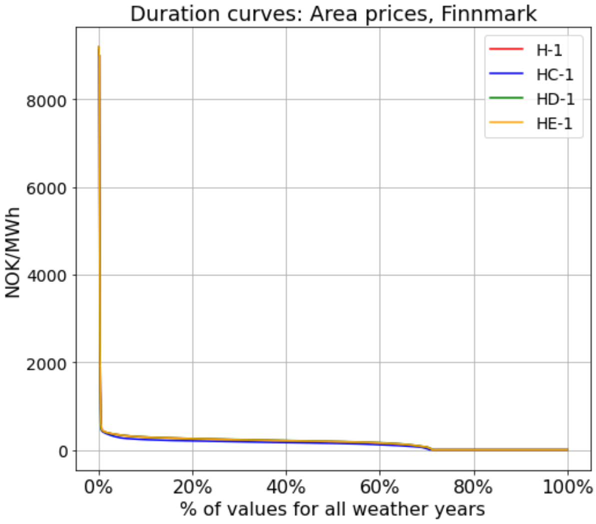

Figure 248: Duration curves for the area prices for Finnmark for dataset H

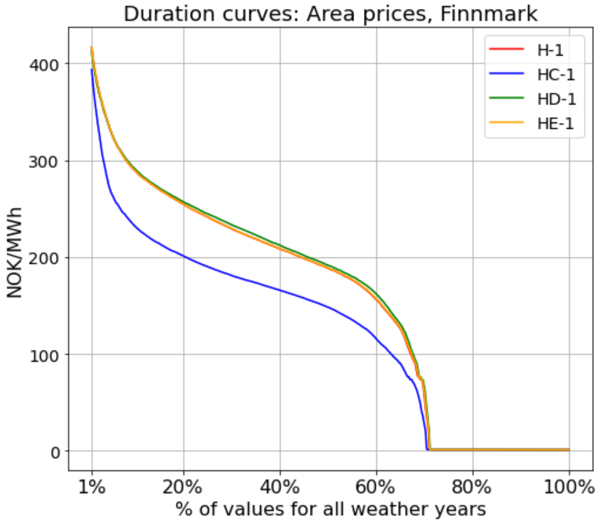

Figure 249: Duration curves for the detailed area prices for Finnmark for dataset H

13.15 Appendix O: Reservoir levels for surplus and scarcity situations

Base case

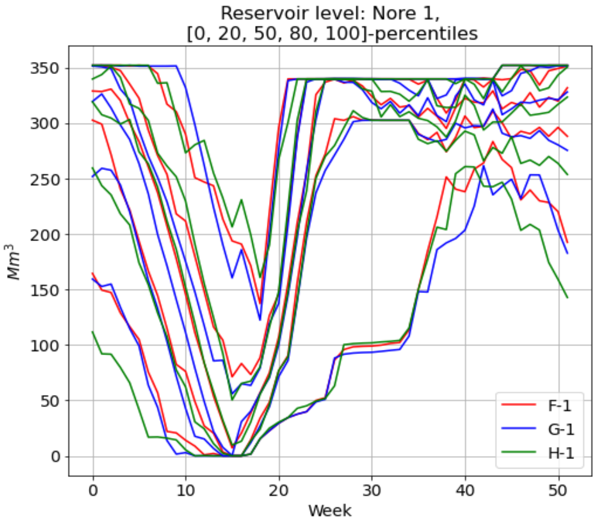

Figure 250: Percentiles for reservoir level for Nore 1 for the base cases

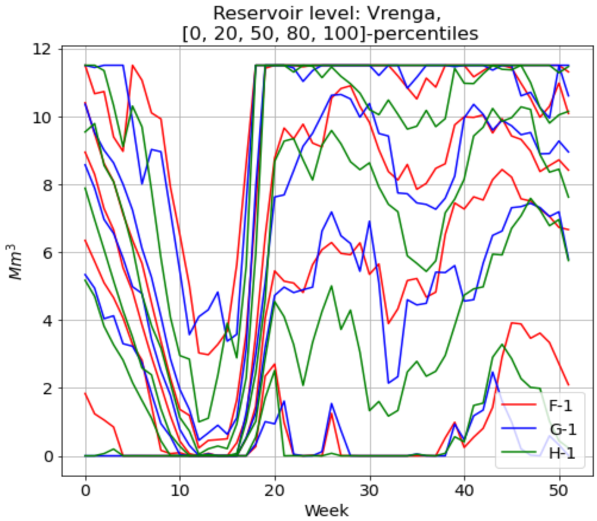

Figure 251: Percentiles for reservoir level for Vrenga for the base cases

Removing cables

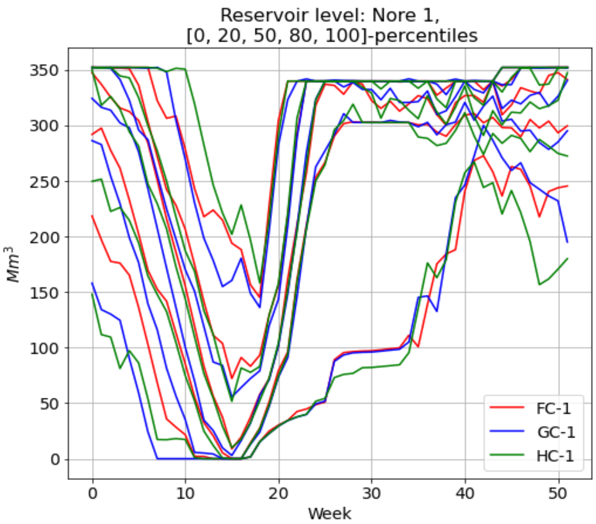

Figure 252: Percentiles for reservoir level for Nore 1 for FC, GC and HC

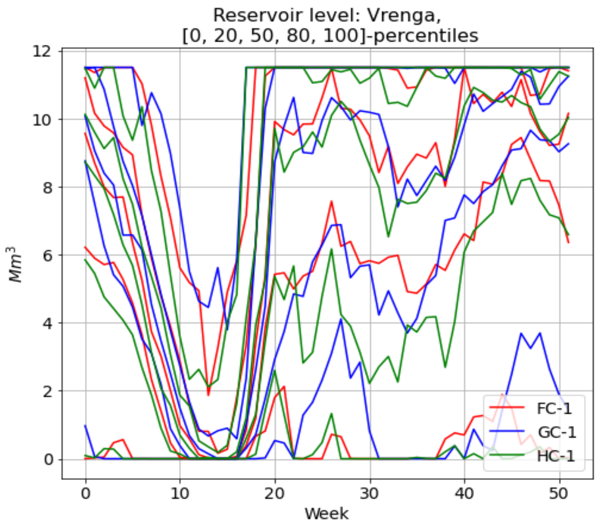

Figure 253: Percentiles for reservoir level for Vrenga for FC, GC and HC

Scailing up the capacity to GB

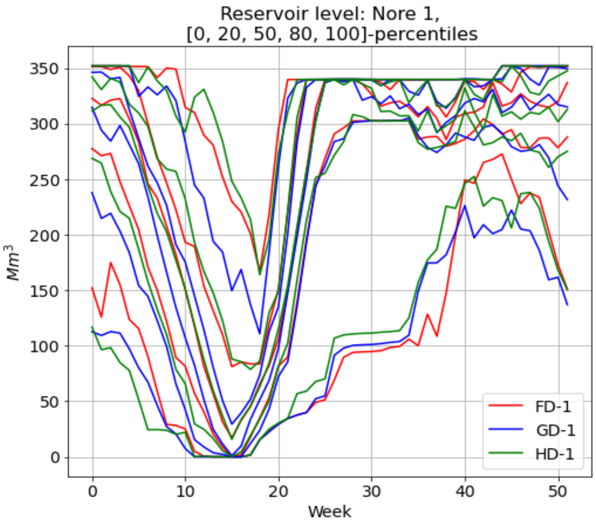

Figure 254: Percentiles for reservoir level for Nore 1 for FD, GD and HD

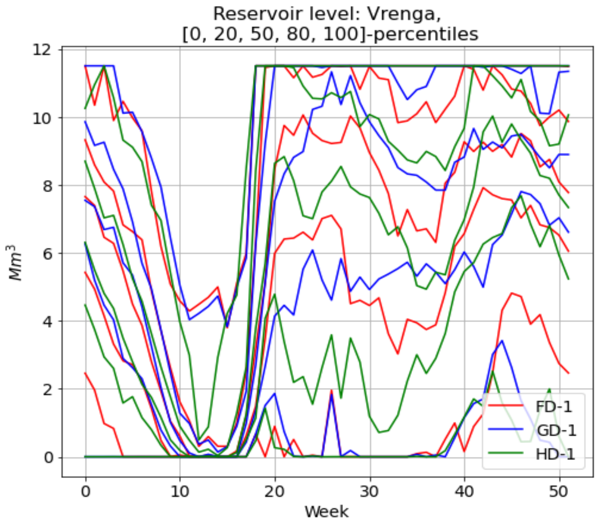

Figure 255: Percentiles for reservoir level for Vrenga for FD, GD and HD

High rationing price

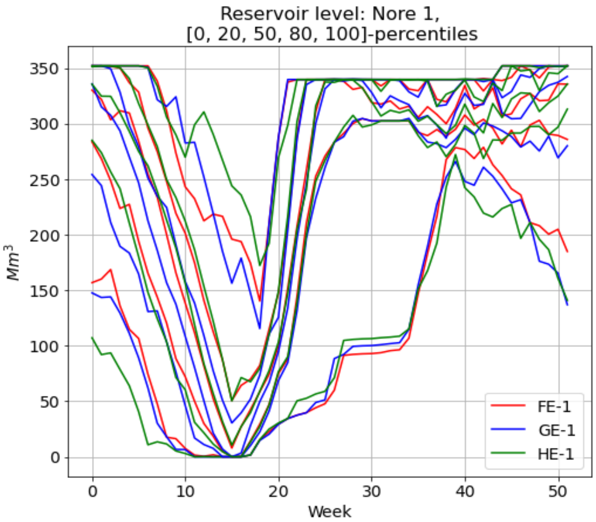

Figure 256: Percentiles for reservoir level for Nore 1 for FE, GE and HE

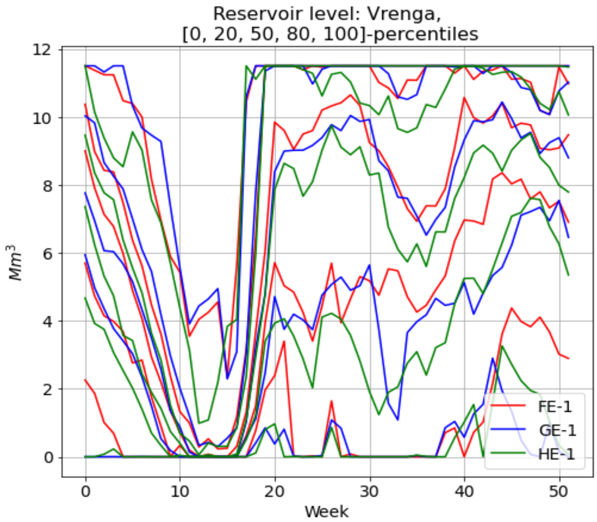

Figure 257: Percentiles for reservoir level for Vrenga for FE, GE and HE

Amaleen Jeyaseelarajah, Mathilde K. Ljøkjel

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