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Norwegian Hydropower Producers' Response to the 2021 Energy Price Shock: An Analysis of the Development in the Water Values

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Abstract

Norwegian electricity prices surged during the last half of 2021. A significant increase in the European gas prices and the prices of carbon allowances, low inflow to the reservoirs in southern Norway, and increased demand due to the post-pandemic rebound of economic activity were central drivers for the increase in the electricity price. Soaring prices in thermal energy sources and diminishing water levels in the reservoir have shown how volatile the electricity price can be in a power system that predominantly relies on hydropower. Consequently, understanding how these price determinants influenced the water values of the Norwegian hydropower producers in 2021, will be an important factor to ensure the energy security in the future.

This paper analyses the development of the water values of 17 Norwegian hydropower plants in price areas NO2 and NO5 in the last half of 2021. Through a double censored regression model, the study finds that 71,4 % of the hydropower plants with reliable results had an increasing trend in the water values, while 21,4 % had a decreasing trend. Furthermore, the study analyses how the hydropower producers reacted to the development in the Norwegian and European energy markets. The study finds that 78,6 % of the hydropower producers increased the water values when the gas price increased, and 71,4 % reduced their water values when the European gas storage levels increased. If the carbon spot price increased, 27 % of the hydropower producers increase the water values, while 84,6 % of the producers lowered the water values when the reservoir filling increased.

By applying the rolling window approach to the double censored regression model, we identified potential responses to the market signals for six of the hydropower plants in the study. The responses suggested that the hydropower producers changed their expectations with respect to the market signal, and thus revised their models. The study found that five producers responded in late August and September, while one plant may have had a reaction in November. The evidence suggests that 100 % of the responses indicated a reaction to the European gas storage filling. It was found that 71 % of the responses were associated with the degree of reservoir filling of the hydropower plant. 43 % of the responses could indicate a reaction to the carbon spot price, and 71 % of the responses were associated with a change in expectations of the gas price. However, there was a great deal of uncertainty related to the results from the rolling window analysis, and the evidence should be viewed with caution.

Acknowledgement

Writing this master's thesis has been both interesting and challenging, and it has been motivating to apply theories and methods that we have learned through the two years of our master's program to a highly relevant real-world topic. Through this project, we have gained valuable competency within the field of hydropower economics and improved our data analysis and Python knowledge and skills. We look forward to continuing our development and using the knowledge in other settings in the future.

First, we are grateful to our supervisor, Olvar Bergland, for his invaluable support and advice throughout this process and for sharing his extensive insight into energy economics and econometrics. Thank you for all the time and effort you have devoted to helping us.

Further, we would like to thank our partners, Fredrikke and Lasse, and our families, for their continuous support, patience, and motivation throughout the months of working on the thesis, and during the years that we have spent studying to get to this point.

Lastly, we would like to thank each other for continuous hard work, support and interesting discussions during this period, and our fellow students for making these two years at NMBU memorable.

Contents

List of acronyms and abbreviations

MW	Megawatt
MWh	Megawatt hour
GW	Gigawatt
GWh	Gigawatt hour
TWh	Terrawatt hour
TSO	Transmission System Operator
OED	Ministry of Petroleum and Energy
Entso-E	European Network of Transmission System Operators for Electricity
Entso-G	European Network of Transmission System Operators for Gas
PV	Present value
NPV	Net Present Value
DAM	Day-Ahead-Market
PS	Pumped Storage
SR	Storage Reservoir
REMIT	Regulation on Wholesale Energy Market Integrity and Transparency
UMM	Urgent Market Messages
NEM	Regulation relating grid regulation and the energy market

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1. Introduction

Following a decade of stable and low electricity prices in Norway, the prices surged in the last half of 2021, especially in the southern price areas (figure 1). In the last week of December 2021, the average electricity price in the southern price area NO2 had increased by 1 482 percent compared to the same week the previous year, while in the northern price area NO4, the weekly average electricity price had increased by 289 percent.[1]

The increase in the electricity price was initially driven by high European gas prices, increased prices on the carbon allowances, low inflow to the reservoirs in southern Norway and increased demand due to the post-pandemic rebound in economic activity (Meld. St. 11.; Statnett, 2022b).

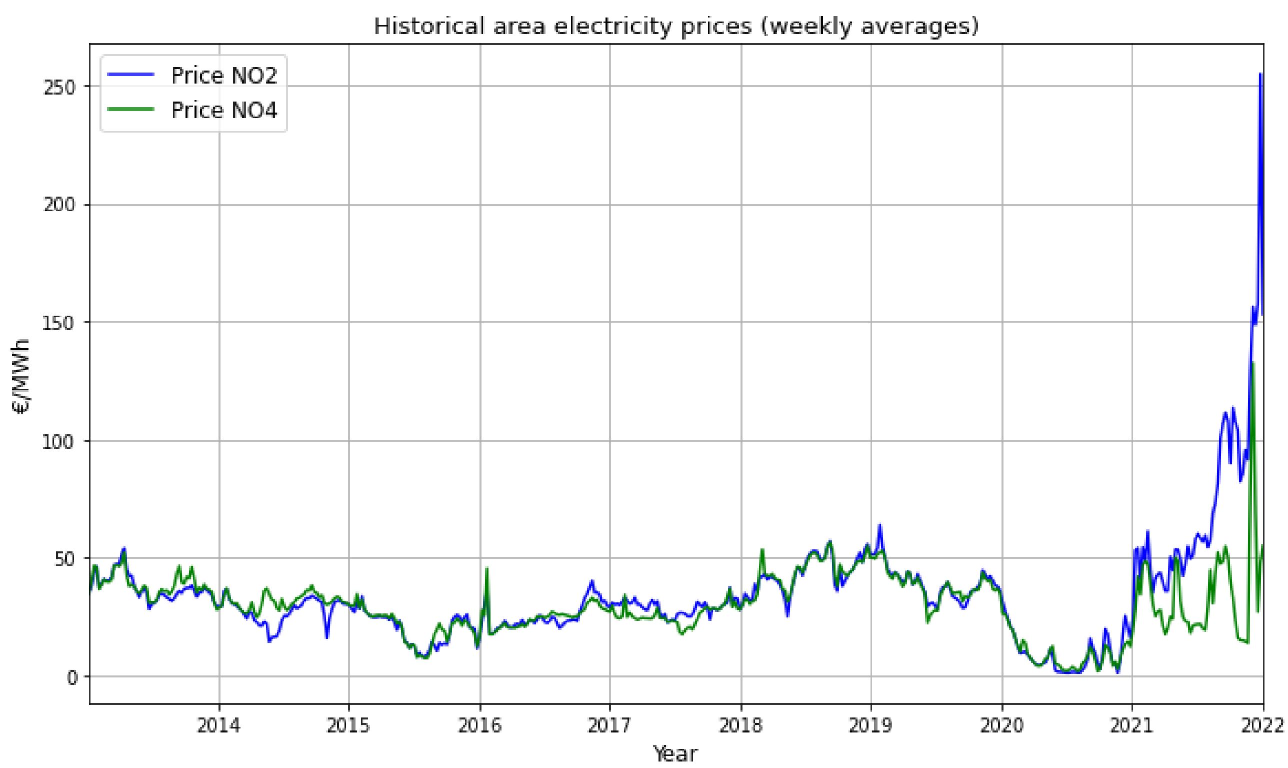

Figure 1: Weekly average electricity price in price areas NO2 and NO4 in Norway (2013 – 2022). NO2 and NO4 illustrates the southern (NO1, NO2, NO5) and northern regions (NO3, NO4) respectively.

[1] See calculation in Appendix 1

The price shock created an unusual situation for the Norwegian hydropower producers to deal with. With hydropower serving as a fundamental part of the energy production in Norway, accounting for 89 % of the energy supply (Energy facts Norway, 2021a), the management of the water resources during a price shock can be significant for the Norwegian energy security. The producers use different models to predict the electricity price and find out when they should produce to get the highest profit on their water. Which models, input variables and methods they are using are not publicly known, as they want to predict better than their competitors. The use of varied models and methods suggest that hydropower producers have different expectations and uncertainties which may result in diverse production pattern and reaction to market signals with varying response time. In a situation with high uncertainty and volatility in the electricity price and the European energy markets, it is important to assess how the external price shock influenced hydropower producers in Norway.

In this paper, we will study how a group of Norwegian hydropower producers' water values developed in the last half of 2021 as a response to changes in the hydropower producers' reservoir filling, as well as to market signals from the European energy markets, such as the gas prices, CO2 prices and gas storage filling. To guide our investigation of this topic we have formulated a general objective, three specific objectives with three corresponding research questions. We will analyse the responses to the market signals separately for each powerplant, and afterward summarize and discuss the results across the price areas. Developments in the market signals influence the hydropower producers' valuation of the water in their reservoirs. The abrupt changes in the market signals in the last six months of 2021 may have led producers to change their expectations with respect to the future development of the market signals. This may in turn have given them an incentive to revise their fundamental models to adapt to the changing situation in the energy markets.

The general objective of the study is:

> *to provide insight into how and when Norwegian hydropower producers reacted to the developments in the Norwegian and European energy markets during the last half of 2021.*

Our specific objectives are:

1. *Analyze the development of the water values for individual hydropower plants.*
2. *Assess how the hydropower plants' water values changed in relation to changes in the European gas prices, CO2 price, reservoir filling and the European gas storage filling.*
3. *Assess if the individual hydropower producers reacted differently or at a different pace with respect to the market signals compared to the other hydropower producers.*

In line with the objectives, the following research questions will be studied:

1. *What were the water values of individual hydropower plants in the period and how did the water values develop in relation to the electricity price?*
2. *How did the gas prices, CO2 prices, reservoir filling and the European gas storage filling influence the water values?*
3. *When did the different hydropower producers respond to the market signals and which signals did they respond to?*

1.1. Organization of the thesis

The thesis is organized as follows. Chapter 2 presents the background, where we first describe the Norwegian power system and types of hydropower plants in Norway as well as the delimitation of the thesis. Chapter 3 describes the theoretical framework, which consists of the physical power market and the water value method, as well as the theoretical calculation of water values using stochastic dynamic programming. In Chapter 4, we present the data and methods applied to the analysis. This includes the double censored regression model, rolling window approach, as well as presentation of the data and data transformations that were used. The results and discussion of the findings are given in Chapter 5, and lastly, Chapter 6 provides concluding remarks, limitations of the study and recommendations for future research within this area.

2. Background

2.1. The power system in Norway

A factor that distinguishes electricity from other goods is that there is currently no simple and cost-effective way to store large quantities of electricity. As storage is difficult and costly, the power producers must collectively produce the equivalent load of electricity that is consumed in the market at each point in time. Temperature and economic circumstances are elements that influence electricity consumption, such that the load has an intricate time pattern and varies over hours, days, weeks, seasons, and years (Cretì & Fontini, 2019). The lack of storage possibilities and the time variability of electricity consumption contribute to the complexity of optimal power production.

The Norwegian electricity sector supply relies primarily on hydropower, which accounts for approximately 88 % of the total generation during normal weather years. Norwegian hydropower has a total installed capacity of 33 GW (Energy facts Norway, 2021a), with an annual energy output of 137,9 TWh, produced across 1760 hydropower plants (NVE, 2023a). Several of Norway's largest hydropower plants, such as Kvilldal and Sima, and largest reservoirs such as Blåsjø, can be found in the southwest of Norway (Graabak et al., 2007). These are areas with steep mountains, lots of rivers, lakes, and wet weather, which makes the area well suited for hydropower production. As a source of energy, hydropower can be characterized as both stable and flexible and differs from other sources because of the hydropower reservoirs. The reservoirs work as storage facilities, where potential energy can be stored. Furthermore, the reservoirs enable short response time and rapid changes in production at low start-up costs (Graabak et al., 2007). Norway holds 1000 such hydropower storage reservoirs that accumulated have a storage capacity of 87 TWh of energy. The Norwegian hydropower reservoirs constitute nearly 50 % of the European reservoir capacity (Energy facts Norway, 2021a). This corresponds to approximately 70 % of the electricity consumed in Norway each year (Energy facts Norway, 2021a; Graabak et al., 2007). The reservoir capacity means that Norway has the opportunity to postpone energy production to a period when consumption is needed and the water has a higher value, like in periods with modest rainfall and during cold winters (Førsund, 2015).

The Norwegian electricity market was reformed from a monopoly market to a liberalized electricity market in the early 1990s (Førsund, 2015; Regjeringen, 2016). The market-based structure encourages competition and improved efficiency and enables Norwegian hydropower producers to make a profit (Li et al., 2011). The deregulation reform led to Norway treading the path of foreign power exchange and establishing the world's first integrated international market for electricity, Nord Pool (Bye & Hope, 2005; Førsund, 2015). Nord Pool enables the export of energy in periods of high domestic supply and foreign demand and imports in periods of low domestic supply and high demand. The exchange possibility provides more flexibility and contributes towards safeguarding the energy security in Norway and Europe today (Statnett, 2021), and will play a key role in the future as the society is expected to become even more reliant on electricity (NOU 2023:3). At the same time, the interconnection with Europe makes the Norwegian power market more vulnerable to external shocks, such as the increased gas prices that we have seen in Europe the past years.

Norway is an elongated country with regional differences between transmission, supply, and demand that are highly dependent on weather patterns. A common price for the whole country will thus be difficult and expensive, as transmission congestion can occur due to limited capacity on the grid, where bottlenecks make it impossible to generate electricity from the cheapest energy source (Cretì & Fontini, 2019). Consequently, Norway is divided into five zonal price areas (Statnett, 2022a), which allow for regional differences in electricity prices, as visualized below in Figure 3. Each price area has its electricity price, which balances supply and demand within the different price areas. It is an example of how the price areas contribute to the efficient use of Norwegian power resources (Statnett, 2022a).

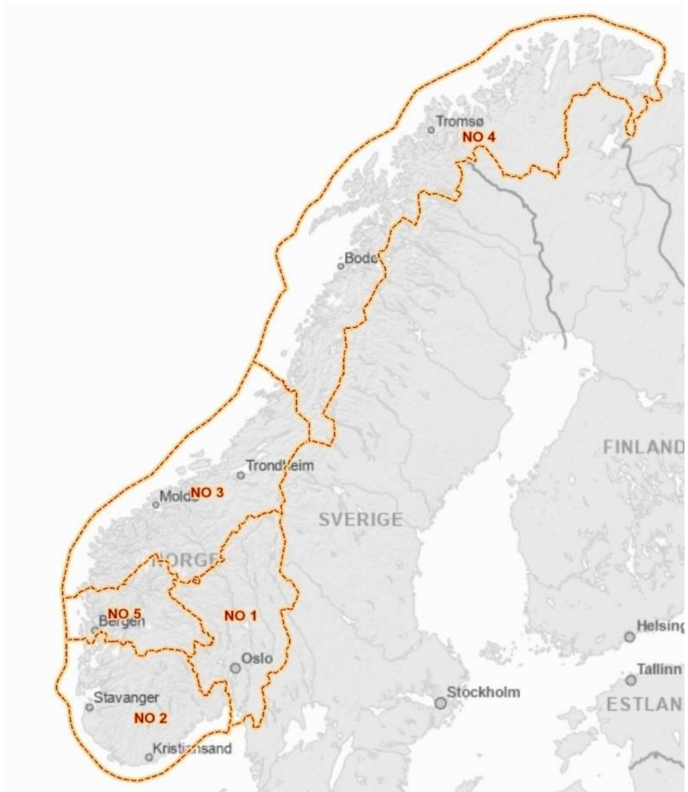

Figure 2: Price areas in Norway (NVE, 2022b)

Norway is connected to the European electricity market with an accumulated exchange capacity of 9 GW, which corresponds to approximately 1 TWh a week (NOU 2023:3). In total, 7 HVDC cables connect NO2 and NO5 with the European market. These price areas are thus much more closely connected to the European power market than the other areas in Norway. When the capacity of the transmission cables is not fully utilized, a market coupling is established between the two areas connected by the cables and the European market, which results in uniform prices. If the capacity is exceeded and we get congestion, a market split occurs, and different prices arise between the areas (Cretì & Fontini, 2019). In the event of high electricity prices in Europe together with a market split within Norway, the price signals in NO2 and NO5 will be more prominent than the rest of the Norwegian price areas.

Historically, Norway has had lower electricity prices than its neighboring countries and has therefore exported more than we have imported over the course of a year.

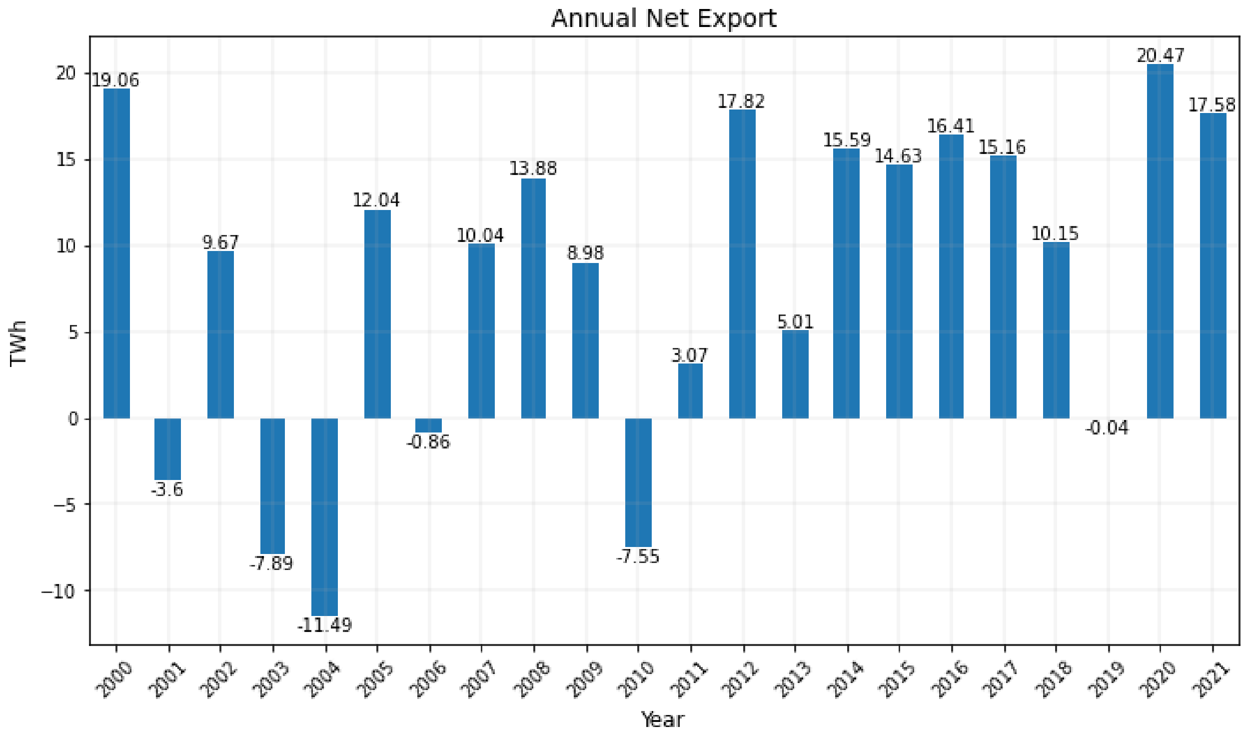

Figure 3: Annual net exports from the year 2000 to 2021 (Aanesen, 2022)

Norway, with its primarily regulated energy system, takes advantage of price fluctuations in the neighboring countries by importing low-cost energy during off-peak hours and exporting higher-priced electricity during peak hours. This approach takes advantage of diverse natural resources and price variations with Europe, which have to a greater extent unregulated- and thermal power sources (Energy Facts Norway, 2021b).

2.2. Types of hydropower plants in Norway

In this section, we give a brief overview of the energy sources used in Norwegian power production. Then we present the three hydropower technologies found in the Norwegian power system and provide insight into their contribution to the country's total energy production.

Most of the Norwegian power production comes from renewable energy sources, such as hydropower and wind, and in addition, a small proportion comes from non-renewable thermal sources. Hydropower makes up 88 % of the total energy production, of which 80 % is from large hydropower plants with an installed capacity of 10 MWh or more. The remaining 8 % comes from small plants, including mini and micro hydropower plants with a capacity of fewer than 10 MWh. Wind and thermal make up the last 12 % of the country's energy production (NOU 2023:3, 2023). Thus, the production of electricity from large hydropower plants is the main source of energy production in Norway. The pie chart below illustrates the distribution of Norwegian energy production in a normal weather year by source.

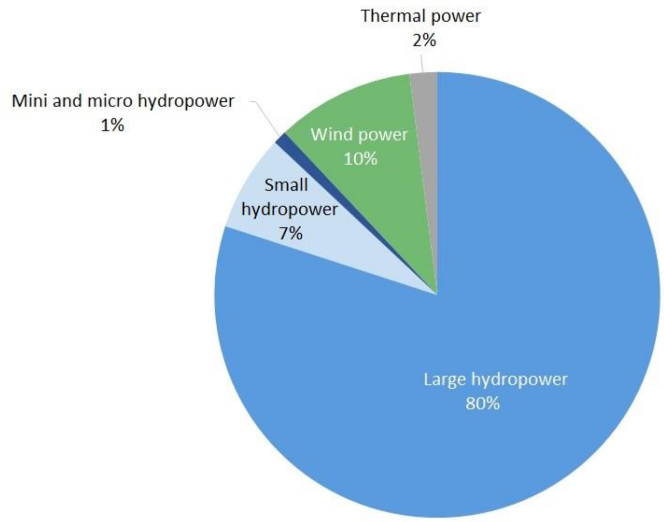

Figure 4: Normal year Norwegian power production, by source (NOU 2023:3)

There are mainly three types of hydropower plants in Norway; storage hydropower plants, run-of-river plants, and pumped storage hydropower plants. These plants differ in several ways such as their location in relation to the water resources, their ability to store water, and other aspects. These types of plants will be presented in the sections below.

2.2.1. Storage hydropower plants

Storage hydropower plants utilize a single or a system of natural or artificial lakes as reservoirs for accumulating precipitation and snowmelt water. The water is released and transported via tunnels and pipes down to the power plant and is converted to electricity. The inflow of water to the reservoirs varies but mainly occurs during the snow-melting season from early May to mid-July, decreases in the summer, and increases slightly during the rainy season from mid-September to late October (Bye & Hope, 2005; Regjeringen, 2011). The storage capability provides a reliable and flexible source of hydropower production throughout the year, and in some cases over several years. It adds great value to the Norwegian power system as water is stored in periods of low demand and can be released to meet the electricity needs of households and industries in periods of high demand. These power plants are essential to the Norwegian energy mix as they contribute to covering both baseload and load during peak demand periods (SNL, 2022).

In Norway, there are 461 storage hydropower plants with a total installed capacity of 25 GW. The annual energy output from these plants is 103,6TWh, which corresponds to 75 % of the country's annual hydropower production. There is a wide range of installed capacities in the individual storage hydropower plants, varying from 0,12 MW for the smallest to 1240 MW for the largest. Of these, 71 plants have an installed capacity of 100 MW or more and contribute with nearly 53 % to the country's annual hydropower production. This includes seven plants that have a capacity of 500 MW or more each, and these plants alone contribute a share of 12 % to the country's annual hydropower production (NVE, 2023a). To sum up, the statistics show that the contribution from storage hydropower plants to the country's total hydropower production is significant and that most of the production comes from the 71 largest plants.

2.2.2. Run-of-river hydropower plants.

Run-of-river plants are hydropower plants that are in a river and utilize the flow of water for energy production. These power plants direct a part of the river flow via tunnels or pipes to the power plant, and then back into the river, a lake, a reservoir, or into the sea. Typically, run-of-river plants are not coupled to a large reservoir, hence the producers have to continuously produce the available water in the river to avoid loss of the water (Førsund, 2015). Consequently, the amount of energy that is generated by these plants is highly reliant on the stochastic inflow of water to the waterway and the installed production capacity (NOU 2023:3). There are significant fluctuations in the production, which peaks during the spring snowmelt and during the summer and autumn when are there is high levels of precipitation (NVE, 2015b). Thus, the run-of-river plant's energy contribution is largest during the summer, when demand is low, and smallest in the winter, when demand is high. Run-of-river plants are considered unregulated and inflexible hydropower plants as their production cannot be controlled beyond producing the water that runs in the river (NOU 2023:3).

Norway has 1290 run-of-river power plants with a total installed capacity of 7,23 GW. The annual energy output from run-of-river plants is 31,54TWh, which corresponds to 23 % of the country's annual hydropower production. The individual plant capacities range from 0,0014 MW to 340 MW, with only 28 plants having a capacity of 50 MW or more. The 28 largest plants contribute a share of 43 % to the annual output from run-of-river plants, equivalent to 10 % of the country's annual hydropower production (NVE, 2023a). Overall, most Norwegian run-of-river plants are small, with a few relatively large plants contributing almost half the total output. The contribution to the country's total hydropower production is moderate in comparison to that of storage hydropower plants.

2.2.3. Pumped storage hydropower plants

Pumped storage hydropower plants are an energy storage technology that involves using electricity generated during low-demand periods to pump water from a lower reservoir to a higher reservoir for storage. During periods with high electricity prices, the stored water is released from the upper reservoir to generate electricity (Pumped Storage Hydropower International Forum, 2021). However, the use of this technology is contingent on the electricity price difference between low-demand periods and high-demand periods for it to be worthwhile and a modern pumped hydropower plant can have a net efficiency of around 85 % (Belsnes, 2022).

Norway has nine pumped storage hydropower plants with a total installed capacity of 1,34 GW. The annual energy output from these plants is 1,82TWh, which corresponds to 1,32 % of the country's hydropower production. The individual installed capacities range from 10,7 MW to 640 MW, of which three plants have capacities equal to or greater than 100 MW. These three plants contribute just below 1 % of the country's hydropower production (NVE, 2023a). Overall, there are few pumped storage hydropower plants in the Norwegian power system, and the contribution to the country's total hydropower production is modest in comparison to that of storage and run-of-river plants.

2.3. Delimitation

In this section, we discuss the focus of the thesis and outline the delimitations that we have made. Some of these delimitations emerged naturally due to limited data, while others have been imposed to define the scope of the thesis.

We have chosen to focus on price areas NO2 and NO5 in the period from August 2021 until the end of the year. The reasons are that the largest price shock occurred in this period and in these two price areas. Furthermore, the largest reservoirs are located there, and most cables connecting Norway to the European power market have been laid in these two price areas. Thus, the underlying factors that we are trying to assess will possibly be more prominent, and it is therefore a sensible delimitation of the thesis to only look at these price areas in that period.

Hydropower plants with an installed capacity of less than 100 MW were excluded since the Entso-E Transparency platform does not have production data for these power plants, and it will be too difficult and time-consuming to obtain the data for these plants in other ways.

We have chosen to focus on the reservoir and pumped storage hydropower plants and exclude the run-of-river hydropower plants, with the explanation that the production in run-of-river hydropower plants is price independent as the flow of water in the river determines production. Pumped storage hydropower plants have been included since none of the plants make use of the reversible pumps in the period that we analyse, thus, they function as normal hydropower plants.

Our aim was to include the largest power plants that have a significant impact. However, some of these plants are located downstream in the waterway, which means that the production could be significantly influenced by production in upstream hydropower plants. Consequently, we have chosen to use the topmost plant in the waterway, which is the first power plant under the topmost reservoir(s). It entails that some very large and important hydropower plants have been omitted from the study, such as Kvilldal, Aurland 1, Tonstad, and Tokke.

To be able to include a proper number of hydropower plants in our study, we have set a restriction that none of the included power plants can have an upstream power plant with an installed capacity exceeding 10 MW upstream in the waterway. We assume that since the included plants have a significantly larger installed capacity, the small power plant above will have a limited effect on the production decisions of the operators. Lysebotn II is one exception. Breiava hydropower plant has an installed capacity of 14,8 MW and is located far above Lysebotn II. The water that flows out of Breiava hydropower plant runs via Lyngsvatn which is a substantial reservoir. Hence, we assume that the production in Lysebotn II is independent of the production in Breiava in the short run.

The delimitation resulted in a focus on 17 hydropower plants operated by Statkraft, Lyse, Agder Energi, Skagerak, Hafslund Eco, Sira-Kvina kraftselskap, Aktieselskabet Tysse-faldene, Hydro Energi and Østfold Energi. The characteristics of each of these hydropower plants are described in Appendix 3. The location of the power plants is visualized in Figure 5.

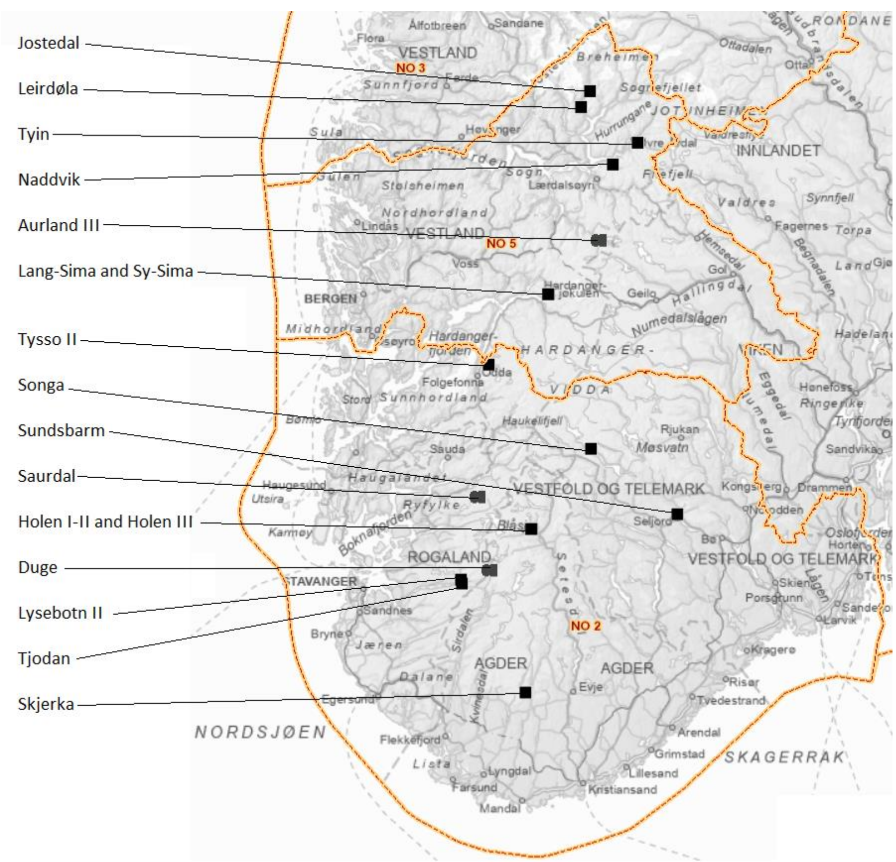

Figure 5: Relevant power plants in price area NO2 and NO5 (NVE, 2022b)

3. Theory

3.1. Nord Pool and the physical power market

Nord Pool is a European power exchange that facilitates the physical power market and aims to organize and operate a marketplace for the physical trading of power (Nord Pool, n.d.-a). It was founded in 2001 and is owned by Euronext and the Nordic and Baltic system operators through TSO Holding (Askheim, 2019; Nord Pool, n.d.-a).

The day-ahead market is the main market at Nord Pool, and it is primarily where all the power trading takes place (Energy Facts Norway, 2021b). The participants can sell or buy electricity for the next day in the price area they are located. It works so that the producers bid into the market how many MWh they want to produce and at what price, which forms an aggregate supply curve. Energy suppliers bid into the market how much MWh they want to buy and at what price, which makes up the demand curve (Nord Pool, n.d.-c). The market closes at 12.00 pm and the European market is cleared at the same time, via a common European market link, SDAC, and Euphemia, which calculates the price in each price area with the same price algorithm (NEMO, 2020; Stortinget, 2022).

The bids are ranked in ascending order for each price area and hour of the next day, and how much electricity is to be transferred between the price areas. The price in each area is set where the market clears, with the last energy unit covering demand. This approach provides maximum value-added by ensuring that producers get their marginal costs covered while consumers are not charged prices exceeding their willingness to pay (Tennbakk, 2022). The auction format is pay-as-cleared, which means that all producers in the price area who bid below the clearing price produce the next day and are paid the clearing price (Cretì & Fontini, 2019). The producers who bid above the clearing price do not produce in the day-ahead market. The producers thus profit from the difference between the clearing price and the price they bid into the market.

According to the ACER (2021) guidance regarding the interpretation of REMIT and NEM, the producers are required to submit bids that reflect their marginal cost into the market, otherwise the bidding may be interpreted as market manipulation. The same applies to not bidding available production capacity into the market. Although Norway has not implemented REMIT, the regulatory authority for energy (RME) refers to the Acer guidance when interpreting regulation relating grid regulation and the energy market (NEM), since the Norwegian power market is deeply integrated with the European power market (RME, 2023). Marginal pricing ensures that the cheapest energy resources are used first, which contributes to the lowest possible electricity price for society (NOU 2019:16), which can be visualized in a merit order curve that displays the marginal costs of different energy sources. The bids are ranked in ascending order for each price area and hour of the next day, and how much electricity is to be transferred between the price areas. The price in each area is set where the market clears, with the last energy unit covering demand. This approach provides maximum value-added by ensuring that producers get their marginal costs covered while consumers are not charged prices exceeding their willingness to pay (Tennbakk, 2022).

The visualization below is a typical example of a merit order curve, where the cheapest energy sources such as intermittent energy and nuclear are used first before other energy sources with higher marginal costs increase continuously throughout the supply curve, which is illustrated by each price step. The market is cleared where the demand intersects the supply curve, which results in a market clearing price and amount of MWh that needs to be produced.

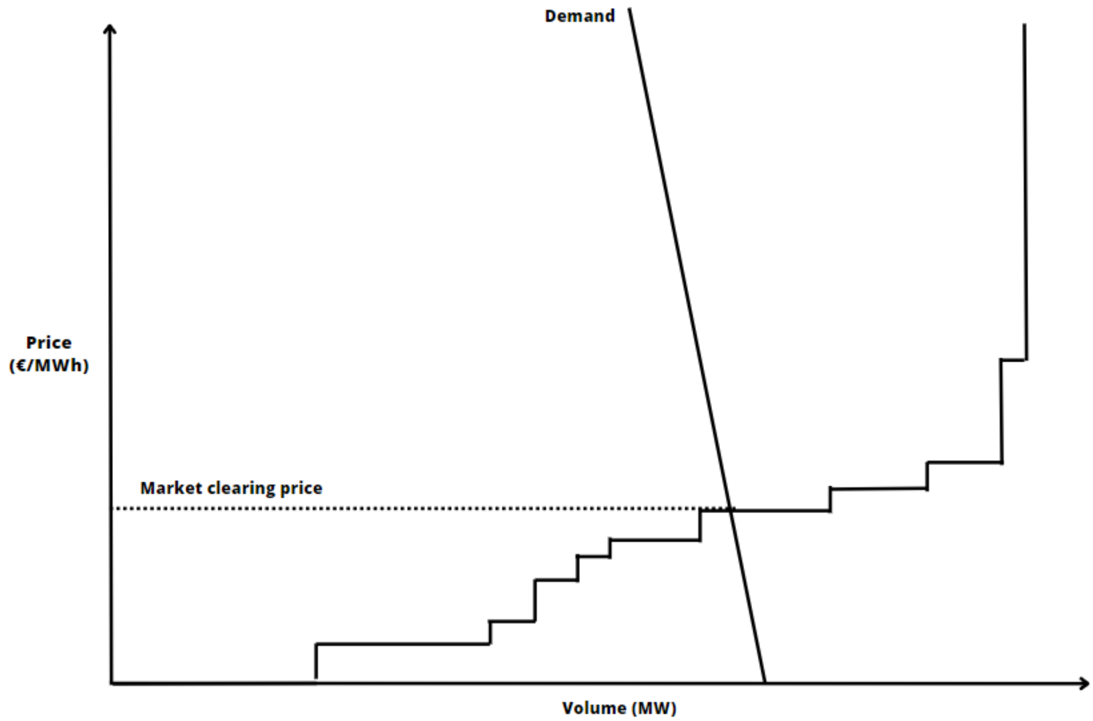

Figure 6: Merit order curve

When demand in the market is higher, the demand crosses higher on the supply curve and more expensive energy sources must be produced to meet demand. If the marginal costs of each individual energy source increase, the producers will thus move further to the right and up the merit order curve and conversely if the marginal costs decrease, producers will shift lower on the merit order curve.

3.2. The water value.

The day-ahead market at Nord Pool requires that producers bid marginal costs to have an efficient outcome, as stated in the previous section. However, hydropower producers who have minimal production costs, free primary sources, and the opportunity to save water, are in a unique position. Regulated hydropower has an opportunity cost, called water value, as production today means sacrificing the potential to use the same water for production in the future (Førsund et al., 2005). In essence, it is the profits they forgo in the future by choosing to produce today. The producers thus calculate a price for the water they have by assessing what they can get for the water in the future if one does not produce today. And it is the water value that constitutes the marginal cost they bid for Nord Pool (ACER, 2021).

The method for calculating a water value was first developed in the 1950s and further implemented in Norway in the early 1960s (Aam, 2016). It is a dynamic problem given information on fundamental factors, among other things, demand, hydro metrological data, transmission capacity, production, and prices from unregulated- and thermal energy sources, production capacity as well as minimum water flow (Wolfgang et al., 2007).

The hydropower optimization problem is typically segmented into three sub-categories based on the time horizon of the planning periods. These are the long-, medium- and short-term hydropower optimization problems. The long- and medium-term problems are usually formulated over a time-horizon of respectively five and one years (Fosso & Belsnes, 2004), whereas the short-term optimization problem typically has a time-horizon of a day or a week, with a time resolution equal to or less than an hour. The short-term optimization problem is closely linked to the long-term strategy (Fleten & Kristoffersen, 2008), and the medium-term problem serves as a link between the two such that the long-term strategy is reflected in the short-term process (Fosso & Belsnes, 2004). Therefore, the hydropower producers must evaluate the worth of their actions today against the consequences for the future outcome. The short-term plan is generated with different tools, ranging from advanced optimization models to simple spreadsheets (Wolfgang et al., 2007).

The power producers must make ongoing calculations about the value of the water they have, to assess whether they should produce or save the water, if expectations of greater profits are higher later. If the electricity price is higher than the water value, it is optimal to produce. If the price is lower, it is optimal to save the water. If the producers price their water too low than optimal, it contributes to them producing more than is ideal, and the savings in the reservoirs could become too small, which can contribute to higher prices in the long run and future scarcity. If they price their water too high, they could save too much on the water, which can contribute to increasing the risk of flooding and overflow of reservoirs in the longer term in addition to higher electricity prices in the short run.

An optimum reservoir allocation is thus a balancing act between storing water for periods of high price and avoiding flooding and loss of water (Wolfgang et al., 2007). The water value varies between reservoirs, depending on how big they are and where in the waterway they are located. The visualization below illustrates an example from a power producer where each price step displays different reservoirs with different water values. The power producer bid the water values into the day-ahead market, and the market clearing price is set where demand intersects supply, and the power plants associated with the reservoirs below the market price produce, and the power plants above do not. Thus, optimal production will occur for the power plants below the market clearing price and those above it will be optimal to save for later.

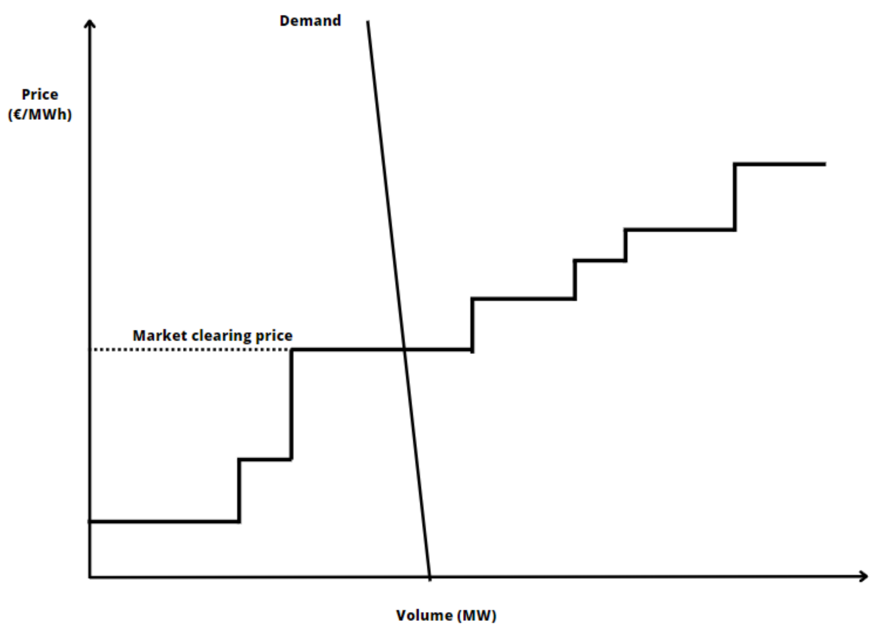

Figure 7: Different water values for different reservoirs

The producers usually save a large part of the water in late spring and summer when there is a large inflow and lower demand, until winter when there is low inflow and higher demand. They produce more during the winter when the price is higher and make room in the reservoir when the inflow from the meltwater comes in the spring (NVE, 2015a).

When the reservoir levels are low, producers place greater importance on producing during price peaks to maximize their limited water resources. For producers in NO2 and NO5, who are more closely connected to the European energy market through transmission cables, the capacity of the transmission cables and price expectations in connected regions will be decisive in determining the optimal water values. In Germany, the market price is usually set by thermal energy, hence an increase in thermal prices and Co2 prices will be influenced and reflected in the Norwegian water values, especially when the reservoir levels are low (Birkelund et al., 2021). Consequently, the water values similarly follow thermal energy sources higher on the merit order curve when the price of thermal energy increases and the market clearance takes place at a higher level than previously, as visualized below in Figure 8.

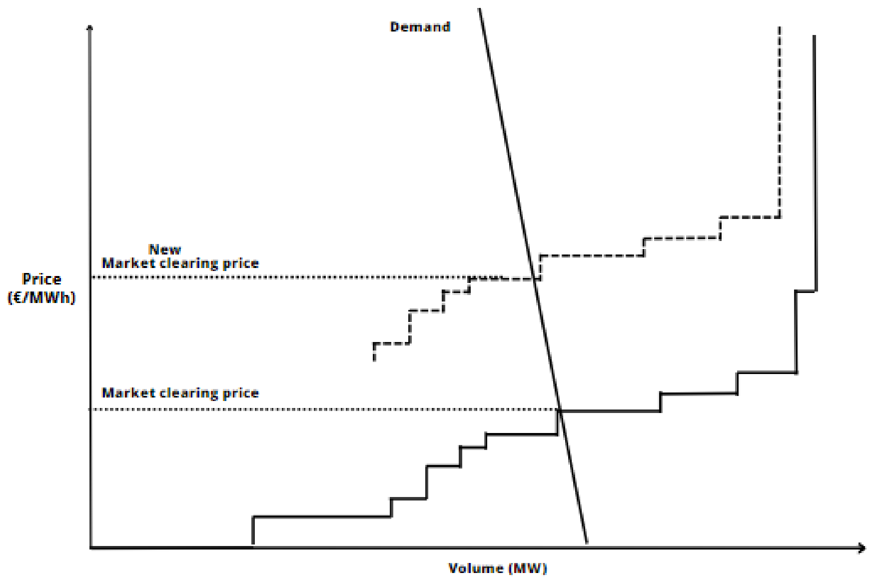

Figure 8: The shift in the merit order curve with high thermal prices and low reservoirs

3.3. The stochastic hydropower production problem

In this section, we demonstrate the fundamental concept of optimal hydropower production with dynamic programming. We explain how a hydropower-producing company (HPP) arrives at an optimal time pattern for production and how they model the bids they submit to the day-ahead market. Our formulation of the model is based on and inspired by the models and theories from

Aasgård et al. (2018), Førsund (2015), Adda and Cooper (2003), and Miranda and Fackler (2004).

The HPPs with storage capacity face a stochastic dynamic decision problem in the process of finding an optimal strategy for the utilization of the water in the reservoirs. The producers have the opportunity to utilize the water today or save it for future production. However, the HPPs production today combined with uncertainty associated with reservoir inflow due to unpredictable weather situations affects future production possibilities (Fosso & Belsnes, 2004). Thus, the HPPs face the essential question of which time pattern the water should be exploited given the available production capacity in each time period (Førsund, 2015).

The classical long-term optimization problem was discussed in the section on the water values. In our analysis, the relevant long-term horizon is relatively short compared to the five years in the classical setup. As we analyse a period with price shocks, a shorter horizon of 1-3 years allows the hydropower producers to revise and adapt their strategies in response to the changing conditions in the market. The long-term problem is modelled similarly to the infinite horizon problem, but with fixed capacities. It means that there are no new investments during the planning horizon e.g., in new reservoir or production capacities. By fixing the capacities, the focus remains on optimizing the allocation of the water over a short-term horizon and maximizing profits.

Financial incentives are an important part of the decision, as the producers want to move the production to periods when they can get a high return on the water. However, the producers face reservoir constraints, and the opportunity for saving water is limited. The reservoirs are typically filled in periods when water is in abundance and saved for periods of scarcity. If the producers save too much water and the inflow is higher than expected, they run the risk of water spillage by overflowing the reservoirs. The optimal solution is therefore a balance between financial incentives and avoiding loss of water. A widely used mathematical method for solving the hydropower producers' optimization problem is stochastic dynamic programming. The method takes the uncertain inflow into account and produces the water values for the stored water, which in turn allows the producers to model the production problem over time (Wolfgang et al., 2007). In order to plan and decide on the best possible utilization of the water for energy production, the companies use various fundamental models and software. The model that is most commonly used in the Nordic context is Samkjøringsmodellen (for more details, see Førsund et al. (2005)).

In the following model for optimal hydropower production, we consider an HPP with a single power plant, one reservoir with maximum storage capacity R^{Max} and fixed production capacity K. The reservoir capacity may be a single reservoir for some plants, or in other cases the combination of reservoirs associated with the powerplant. The model is simplified as we only focus on the basic aspects and omit factors that are typically important in more comprehensive models like Samkjøringsmodellen. The model we present has two main characteristics: the reservoir transition balance and the model for the hydropower plant. The reservoir filling change over time because of several factors. The reservoir is drawn down when the water is used to generate energy or to keep a certain level of flow in a river. Moreover, the reservoir is replenished by precipitation and snowmelt, and can overflow if the reservoir capacity is reached.

In our model, $t = 1, \ldots, \infty$ denotes the hour over an infinite planning horizon. The planning is performed sequentially, hour by hour, one hour ahead of time. The time period taken as relevant for the decision is an hour because the HPPs decide on sets of production volume and price for each separate hour of the following day, which they bid into Nord Pool's day-ahead market (Energy Facts Norway, 2021b). Furthermore, we consider the hydropower production problem to be an ongoing problem that does not terminate. Hence, it is relevant with an infinite planning horizon. s is the *state of nature* and represents the natural uncertainty about the realized future value of the inflow. The inflow is denoted $f_t^s \geq 0$, and the inflow in hour t can take on any value $s = 1, \ldots, S$. The reservoir filling transition between two periods can be expressed as:

$$R_{t+1}^s = R_t + f_t^s - o_t^s - x_t \tag{1}$$

R_{t+1}^s is the reservoir filling at the end of period $t + 1$ in state s and R_t is the reservoir filling at the end of period t. The value of R_t is known at period t, but the value of the reservoir filling in the next period is not known and relies on factors such as the realized value of the inflow. The overflow in state s in period t is denoted $o_t^s \geq 0$. Lastly, x_t is the quantity of water in energy units withdrawn from the reservoir storage for production in period t. The transition equation (1) states that the stochastic reservoir filling at the end of period $t+1$ is a function of the accumulation of water in the reservoir over the planning horizon. It means that the reservoir filling in hour $t+1$ must equal the reservoir filling at the end of the previous hour plus the inflow and less the spillage and production that occurred within this hour. The reservoir filling must be within the known reservoir capacity, $R_{Min} \geq R_t \geq R^{Max}$, due to physical, environmental, and regulatory reasons. The topology of the hydropower system under consideration as well as the dynamics of water accumulation in the reservoir in a single period is illustrated in the figure below. Production capacity and the connection to the power market are also included for illustrative purposes.

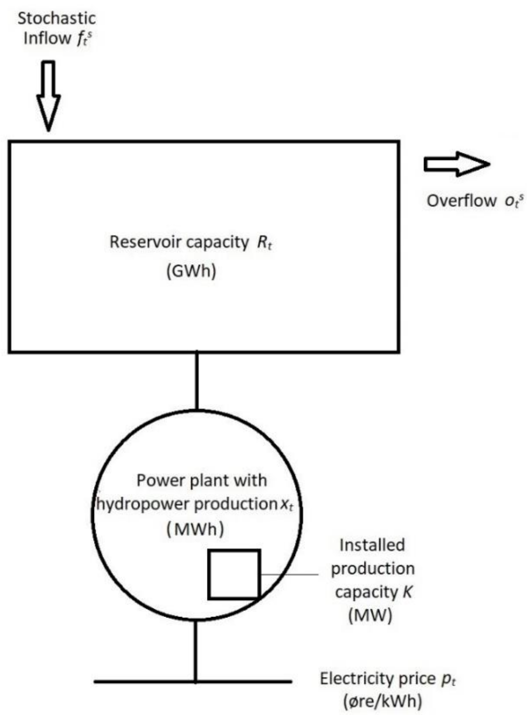

Figure 9: Typology and water accumulation dynamics

The optimal production strategy of the HPP is essentially a trade-off between income today and expected future earnings, and the aim is to strike a balance between the current and the expected future profits. The producer wants to decide on the quantity of water to produce in each period to maximize the net present value (NPV) of the flow of single-period profits in the future.

In the following equation, the p_t denotes the electricity price in period t. c is the unit cost and we ignore other costs such as social costs, capital costs and such. r denotes the rate of discount and the rate is assumed to be the same for all periods. A high discount rate put less emphasis on future periods in Eq. (2), and a low discount rate yields the opposite. Hereafter, δ will denote the discount factor, $(1 + \mathrm{r})^{-1}$, to ease the notation. $\pi_s \geq 0$ represents the probability that any state of nature s ∈ S occurs, where S is the collection of all mutually exclusive and jointly exhaustive s. Furthermore, $\sum_{s \in S} \pi_s = 1$ denotes the sum of the probabilities across all states in S, and is equal to 1. E_π denotes the expectation with respect to the distribution of π. The HPPs problem can be written like the following fundamental recurrence equation:

$$
\begin{aligned}
V(R_t) &= \max_{x_t}(p_t - c)x_t + (1+r)^{-1}\sum_{s \in S} \pi_s V((R_t + f_t^{\,s} - o_t^s - x_t)) \\
&= \max_{x_t}(p_t - c)x_t + (1+r)^{-1} E_\pi V(R_{t+1}^s)
\end{aligned}
\tag{2}
$$

With the capacity constraints:

$$0 \leq x_t \leq K \tag{3}$$

$$0 \leq x_t \leq R_t \tag{4}$$

The fundamental recurrence equation shows that the value of the reservoir filling R_t in period $t, V(R_t),$ is the sum of the optimal earnings in period t and the discounted expected future income given the chosen quantity of production in period t. The HPP has limited generation capacity and reservoir filling but does not necessarily utilize all available capacity. Hence, the constraints in Eq. (3) and (4) state that the production in each period must be non-negative and less or equal to the smallest value of the generation capacity K and the reservoir filling R_t. As we do not consider overflow or the upper reservoir limit relevant constraints in our analysis, we leave them out.

The single-period maximation problem can be set up as a Lagrange problem:

$$L = (p - c)x_t + \delta E_\pi V(R_t + f_t^s - x_t - o_t^s) + \lambda_t(K - x_t) + \theta_t(R_t - x_t) \tag{5}$$

We take the partial derivative of the Lagrangian with respect to x_t, λ_t and θ_t, and arrive at the following Kuhn-Tucker (K-T) conditions for the production, x_t:

$$\frac{\partial L}{\partial x_t} = (p - c) - \lambda_t - \theta_t + \delta \frac{\partial E_\pi V(R_{t+1}^s)}{\partial R_{t+1}}(-1) \leq 0 \qquad x_t \geq 0 \quad \text{and} \quad x_t \frac{\partial L}{\partial x_t} = 0 \tag{6}$$

$$\frac{\partial L}{\partial \lambda_t} = K - x_t \geq 0 \qquad \lambda_t \geq 0 \quad \text{and} \quad \lambda_t \frac{\partial L}{\partial \lambda_t} = 0 \tag{7}$$

$$\frac{\partial L}{\partial \theta_t} = R_t - x_t \geq 0 \qquad \theta_t \geq 0 \quad \text{and} \quad \theta_t \frac{\partial L}{\partial \theta_t} = 0 \tag{8}$$

The K-T multiplier λ_t can be interpreted as the marginal value of relaxing the generation capacity constraint, and is the additional value that the producer can gain from increasing the generation capacity by a small amount at time *t*. Similarly, the θ_t multiplier is the marginal value of relaxing the reservoir filling constraint and is the additional benefit that the producer can gain from a small increase in the reservoir filling. The purpose of the second constraint is to avoid that the reservoir filling becoming negative. If the hydropower producer is drawing down the reservoir completely and the reservoir filling is less than the generation capacity, $K > R_t$, then the constraint will be positive, $\theta_t > 0$. It means that the additional value that that the producer can gain by a small increase in the reservoir filling is positive. Conversely, if $K < R_t$, then $\theta_t = 0$, thus, the additional value that the producer can gain by a small increase in the reservoir filling is zero. For a detailed explanation of Kuhn-Tucker conditions, see Chiang and Wainwright (2005).

The interior solution can be written as follows:

$$p - c = \delta \frac{\partial E_\pi V(R_{t+1}^s)}{\partial R_{t+1}} \tag{9}$$

Where the marginal per unit net revenue, $p - c$, is equivalent to the water value in the next period, which is the expected marginal value of the water in the reservoir in the next period. The hydropower producer can estimate that the water value in the next period exceeds the net revenue. In such cases, the HPP will prefer to save water for future utilization, and thus opt out of production today, $x_t = 0$, in favour of future production. This situation can be expressed as:

$$p - c < \delta \frac{\partial E_\pi V(R_{t+1}^s)}{\partial R_{t+1}} \qquad \text{where } x_t = 0 \tag{10}$$

If, on the other hand, the future period water value is estimated to be less than the net revenue, the HPP will prefer to use the water for production today rather than to save it for later. Hence, the HPP will produce x_t corresponding to the maximum capacity, x_{Max}. This situation can be expressed as:

$$p - c > \delta \frac{\partial E_\pi V(R_{t+1}^s)}{\partial R_{t+1}} \qquad \text{where } x_t = x_{max} \tag{11}$$

3.4. Previous studies

Few previous studies have been done on the topic of how Norwegian hydropower producers' water values developed in relation to the market signals from the European power market as well as the reservoir filling in Norwegian reservoirs in the autumn of 2021. However, there are some studies that look into related topics, such as optimality in bidding to the Nord Pool market, optimal use of reservoir water during the last half of 2021 and the relationship between the reservoir filling and the electricity price.

In a conference paper, Alnæs et al. (2013) analysed the rationality in the actual submitted bids to the day-ahead market at Nord Pool from three Norwegian medium to large sized reservoir hydropower producers during four two weeks periods in 2011. The periods represented the four seasons through the year. The authors compared bids from the hydropower producers against perfect price information and found that the producers perform well with a potential increase in income of 5,4 % as an average over the eight-week period. The conclusion of the study was that bids were not always rational, but that the consequences were limited. Furthermore, they found that the producers bid more optimally during the spring and winter than in the summer and autumn, and that with higher price volatility makes it more difficult to bid optimally.

As a part of a thorough assessment of the power situation in 2021-2022, Mo et al. (2022) on request from the Ministry of Petroleum and Energy (OED), have investigated what would have been the optimal use of the water in the reservoirs in the last half of 2021. The authors used detailed data on the Norwegian power market as well as data from the European power market. The study was conducted by using Samkjøringsmodellen. The authors found that the hydro producers underestimated both the water value and price forecast which led to that they produced more water than was economically optimal, even though the water levels in the reservoirs were declining. They also found that the reservoirs were drawn down more than the price shock would imply.

A master's thesis assessed the relationship between the degree of filling in Norwegian reservoirs and the Norwegian electricity prices. Tran (2010) used data from 2008 and 2009, including the degree of reservoir filling in Norway and for each price area, average temperature data in degree Celsius, data on net import, and weekly average electricity price data for Norway and for each price area. Several time series regression analyses were run to investigate if the Norwegian electricity prices reflects the reservoir filling in the Norwegian reservoirs. The author concluded that there is a relationship between the Norwegian electricity prices and the reservoir filling in Norway, and that it is likely due to inflow over longer periods, such as from year to year, rather than shorter period, such as from week to week.

4. Methods and Data

In this chapter, the data, econometric methods, and assumptions that were used in the analysis will be presented. The double censored regression model as well as the rolling window method will be explained. All data management and analysis were performed in Python. The program package RegModels was used, which is developed and supplied by Professor Olvar Bergland at NMBU. Various program packages may produce slightly different parameter estimates and standard errors for Maximum Likelihood Estimates (Hill et al., 2011). However, Professor Bergland has verified numerical results from using the package against Stata. Hence, we evaluate the package to be appropriate for this study.

Secondary historical data from multiple sources was collected which included Norwegian electricity prices for price areas NO2 and NO5, city temperatures, reservoir filling data per reservoir, carbon spot prices, gas prices, European gas storage filling, and generation per generation unit data. It is a time series for each hydropower producer, and includes hourly observations from August 1st through December 31st, 2021, amounting to 3672 observations. The data set is complete with observations for all independent variables for all the hydropower producers in the sample, both during periods of generation and non-generation.

4.1. Data

4.1.1. Electricity price in NO2 and NO5

To model the hydropower producer's water values and compare them to the area spot price, we had to use electricity price data. Professor Bergland provided us with data on Norwegian electricity prices, which had been obtained directly from Nord Pool. The data set contains hourly observations of the electricity price for each price area in Norway, measured in euros per megawatt hour (€/ MWh). The illustration below shows the development in the period of interest of the spot price in the two price areas that are relevant to this study. The figure shows that the two prices are mostly connected, with some deviations when there is a market split between the areas.

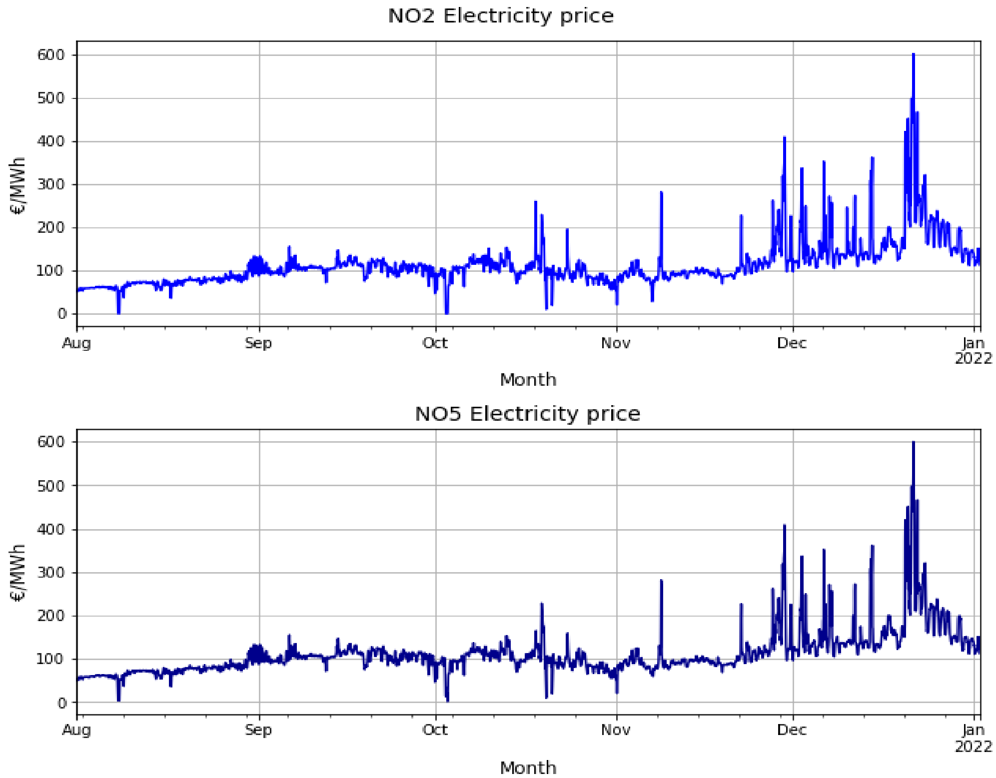

Figure 10: Electricity price per hour in NO2 and NO5 Aug. 2021- Jan.2022

NO2 price ranged from -1,97 €/MWh at 02:00 during the night on the 3rd of October and peaked at 16:00 in the afternoon on the 21st of December at 600,16 €/MWh. The NO5 price ranged from 1,84 €/MWh at 06:00 on the 3rd of October and peaked at the same time with the same price as NO2, since the markets were coupled at that specific moment. There was a significant price development in this period, and it stands in contrast to the price levels in previous years shown in Figure 1.

4.1.2. Entso-E Generation per generation unit

Assessing the timing of the hydropower production of the selected power plants relative to the electricity price and the predicted water values is a central part of this study. Thus, we obtained hourly data on the actual net generation output of each generator with a capacity of at least 100 MW for the relevant power plants from the European Network of Transmission System Operators for Electricity (Entso-E) Transparency Platform (TP). The individual generator data associated with each power plant was aggregated to get the total production for the entire plant.

When analyzing the characteristics of the different power plants in the sample, we found that Holen generators 1 and 2 are associated with different reservoirs compared to generator 3, but they operate in the same machine hall (Skagerak Kraft, n.d.). Thus, they are considered as two separate power plants in our analysis, Holen I-II and Holen III. The same applies to Sima, where generators 1 and 2 belong to Sy-Sima power plant, and generators 3 and 4 to Lang-Sima (Statkraft, n.d.). In total, generation data from 17 different power plants have been included in our analysis.

During the data examination, we found a missing value for Lysebotn II on August 29 at 06:00. The missing value is most likely due to registration errors, as no indications of omission from the market on urgent market messages (UMM) were found on Nord Pool's website, as an absence requires a message to the market (European Parliament, 2011; NEM, 2019). Given that Lysebotn II did not produce in the hour before or after the missing value, it was replaced with 0.

We observed that some power plants in the sample generated unreasonably low levels of energy over a long period of time, for example Duge. Correspondence with the operator of Duge, Sira-Kvina Kraftselskap revealed that it could be due to faulty data registration, own consumption, or trial operation. Including generation levels that are not intended for the market in the analysis may have a negative impact on the model estimates. It is reasonable to assume that the same applies to low production levels of other power plants as well. Hence, we have set a threshold value for production to the market to 5 MWh for all power plants and consider all production below the threshold as zero generation in the power plant at the given time.

The description on TP does not explicitly specify that the production data is solely for the day-ahead market, and it may thus include production for power purchase agreements (PPA), intraday- and reserve markets, where the pricing is based on other terms than the day-ahead market (Nord Pool, n.d.-b; Statnett, 2023). In cases where the power plants produce for the alternative markets instead of the day-ahead market, it may lead to misinterpretation in the analysis, as we assume that all production is for the day-ahead market. It can result in incorrect estimates during hours when the power plants are not producing for the day-ahead market at all. However, if the production for the alternative markets is in addition to the day-ahead market, it may not impact the analysis, as the quantity produced is not under consideration.

4.1.3. Degree of reservoir filling

Reservoir filling is a crucial factor for operators to consider when determining the water value and energy production, and it serves as an indicator of energy scarcity (NVE, 2019). For the analysis, detailed reservoir data on an individual reservoir level originating from The Norwegian Water Resource and Energy Directorate (NVE) was obtained from EuroPower through Anders Lie Brenna. The individual reservoir filling value is observed on a weekly basis at 24:00 on Sunday evenings, or the nearest prior measurement is taken within 48 hours (NVE, 2019).

Operators most likely know the approximate reservoir filling of a given week on Friday that week and use the information to plan and adjust short-term production. It leads to the assumption that there is a correlation between the water value of the given week and the reservoir filling in the prior week. Based on this, we chose to use five days lagged values for the reservoir filling. In what follows, we use the term reservoir filling to refer to the lagged reservoir filling. The reservoir capacity was constant during the period of interest. To fit the data set, the frequency of the reservoir filling and reservoir capacity was changed to hourly observations, and the backward filling approach was used to fill hours with missing data with the corresponding reservoir content and capacity that week. The transformations we performed to obtain the degree of reservoir filling (in percent), $f_{i,t}$, for each power plant i for every hour t is represented by equation 12.

$$f_{i,t} = \frac{\sum_{r \in R_i} h_{r,t}}{\sum_{r \in R_i} c_r} \times 100 \tag{12}$$

$h_{r,t}$ express the reservoir content in gigawatt hour (GWh) in reservoir r at time t and c_r is the same reservoir's capacity in GWh. The numerator is the sum of the reservoir content for all reservoirs r in the set R_i, which we define as all reservoirs associated with the individual power plant. The denominator represents the sum of the reservoir capacity for all reservoirs in the set R_i.

The graphs below show the reservoir filling for the selected power plants in NO2 and NO5 during the period of interest. The figures also show the aggregated reservoir filling over each price area and the average filling over the previous five years. There were substantial differences in the reservoir filling across several power plants in the period. However, the trend patterns were similar for most, with decreasing levels until mid-September, increasing until November, and then decreasing until the end of the period. Jostedal was the exception, with high filling levels at the beginning of the period and a different filling pattern than the others until November.

The inflow of water to the reservoirs from the start of the period until week 38 was lower than the average inflow in the years 1981-2021. Furthermore, from week 38 and throughout the year, the inflow was significantly higher than the average (Mo et al., 2022).

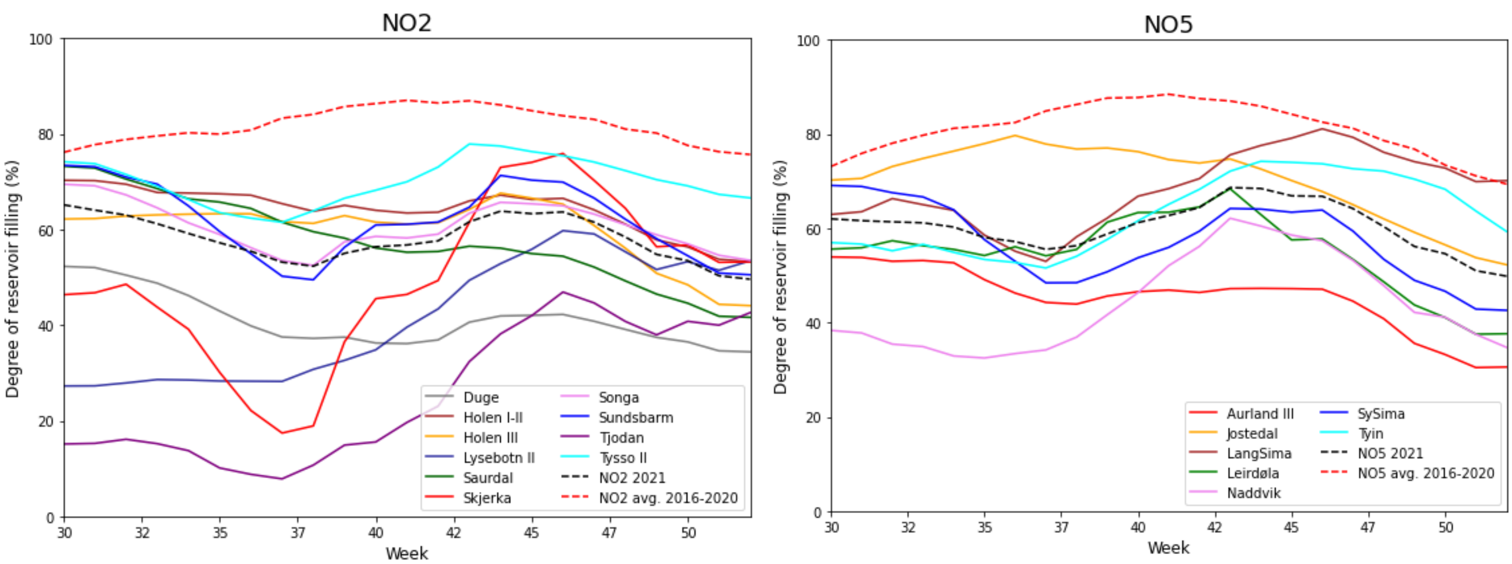

Figure 11: Reservoir filling as a percentage of the reservoir capacity in NO2 and NO5

The reservoir filling data on individual reservoir levels from the last three months is considered competitively sensitive information and is legally confidential (NVE, 2019). We used historical data older than a year on reservoir filling in this thesis.

4.1.4. TTF DA and European Carbon Spot

The TTF day-ahead price is the price of natural gas traded on the Title Transfer Facility (TTF) in the Netherlands. It is one of the largest natural gas trading hubs in Europe and serves as a benchmark for the European natural gas market (European Commission, 2022a). As seen in the figure below the gas price remained stable and low in August 2021 before it started to increase rapidly throughout the year reaching a peak of 183 €/ MWh in late December due to colder weather, lower gas storage levels and muted gas flows from Russia (Buli, 2021).

The price of carbon allowances in the European Union Emission Trading System (EU ETS) has increased significantly in the period of interest, the price of carbon allowances increased from 53 €/ton to a peak of 88 53 €/ton.

Figure 12: Daily TTF DA and European Carbon Spot price Aug. 2021-Jan. 2022

The daily closing price was extracted for both TTF Day Ahead and the carbon spot from Montel. During the data examination, missing values on weekends and holidays were detected for both variables. This issue was addressed by using the Last Observation Carried Forward (LOCF) method, by which we replaced the missing values with the nearest prior closing prices. We consider the method appropriate in our case as the market was closed on the days in question leaving no official closing prices, such that producers likely consider the most recent closing prices for the weekends and holidays when determining the water values. Both prices are lagged by two days, as it is reasonable to presume that the closing price for the carbon spot and the TTF take effect during the bidding for the day-ahead market at Nord Pool on the following day and are first reflected in the water values on the second day. To fit the data set, the frequency of the TTF and the carbon spot was changed to hourly observations, and all hours of the day were filled with the corresponding closing price of the day.

4.1.5. Temperature

We included temperature data in the model, for reasons that will be explained in the section about the model assumptions in 4.2.2.

Temperature data was quarried from the Frost API of the Norwegian Meteorological Institute (MET Norway). The controlled daily mean temperatures in degrees Celcius were obtained from the weather stations Florida and Vossvangen, located in Bergen and Voss respectively, in the NO5 region. Similarly, data was obtained from Våland and Kjevik, located in Stavanger and Kristiansand, in the NO2 region. The weather stations were selected because they were close to the city center and contained complete data. The cities were selected to get variations in temperatures from different locations within the price areas, while also considering their size and potential influence on demand in the event of a temperature change.

The daily mean temperature variables for each city were converted to an hourly time resolution and the observation was forward filled to apply to all hours within the day of the observation. Our interest lay in temperatures that deviated by being colder than the average in previous years, as will be explained in the 4.2.2 section. To achieve this, we constructed a variable with the average of the daily mean from August through December spanning from 2016 to 2020 for each city. We then used this variable together with the daily mean observations from 2021, to extract only those temperature values that deviated from the previous year's average by being colder. The resulting variables consisted of a higher value when the observed temperatures in the cities were colder than the four-year average in prior years.

4.1.6. Aggregated degree of filling of European gas storage capacities

Gas storage facilities in the EU are usually refilled by October, when the heating season starts. However, in October 2021, the peak degree of gas storage filling was 14 % lower than the average level in the previous five years (2016-2020) (European Commission, 2021). Furthermore, by the end of December 2021, the degree of gas storage filling decreased to 19 % below the average level of the previous five years (European Commission, 2022b), and was at its lowest point in a decade (Adolfsen et al., 2023). The figure below shows the trend of the European gas storage filling in 2021 compared to the last decade as well as the mean gas storage filling for the last five years.

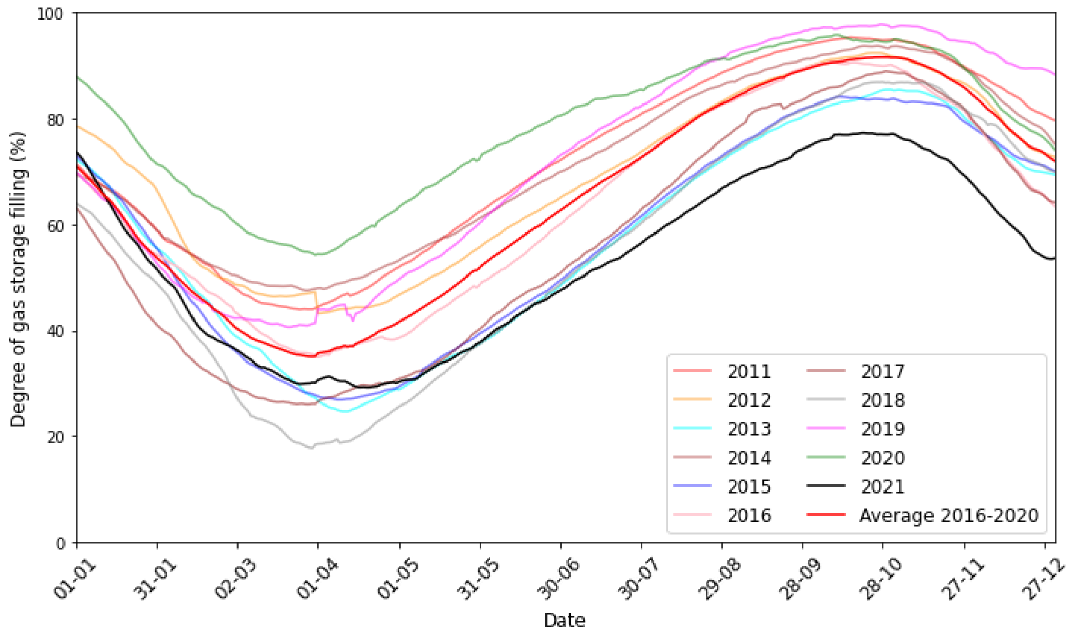

Figure 13: European gas storage filling (%) from 2011-2021.

The low gas storage levels in the EU have been linked to the lower-than-expected export of gas from Russia to the EU in the last six months of 2021. Low gas storage levels, political tension, and low inflow of Russian gas contributed to volatile wholesale gas prices in Europe in Q4 of 2021 (European Commission, 2022b). Based on this, we expect that there is a relationship between the European gas storage levels and the European gas prices and that gas storage is relevant to our analysis. Further explanation will be provided in the section about the model assumptions.

The Aggregated Gas Storage Inventory database (AGSI+) of the Gas Infrastructure Europe (GIE) association holds publicly available historical data on gas storage in Europe (GIE AGSI, 2022).

The data is originally collected by the European Network of Transmission System Operators for Gas (Entso-G). For our analysis, we extracted data with a daily frequency on the European gas stock levels as a percentage of storage capacity from AGSI+. The data is predominantly from EU member states as well as data from the non-EU states Ukraine and the United Kingdom. To fit the data set, we changed the frequency of the data from daily to hourly observations and filled the missing values with the corresponding value of the day. The variable was also lagged by two days, applying the same reasoning as for Carbon Spot and TTF, since the market signals are first reflected in the water values on the second day.

4.2. Methods

4.2.1. The double censored regression model

To predict the water values of the hydropower producer and be able to analyze the development of the water values against the market signals, we used a double censored regression model, which we estimated with the Maximum Likelihood Estimator (MLE). The double censored regression model is a Tobit model based on the work of Tobin from 1958, on estimation with limited dependent variables (Hayashi, 2000; Stock & Watson, 2016). A limited dependent variable is broadly defined as a dependent variable where the values are restricted (Wooldridge, 2021), which applies to our dependent variable in the study. The double censored regression model differs from regular regression models because the dependent variable is censored. Our dependent variable, the water value, is either left or right censored for each observation, and the pattern of censoring varies over time. If the producer is producing in a given hour, the dependent variable is left censored, and the value indicates the upper bound of the water value. Conversely, if the producer does not produce, the dependent variable is right censored, and the value indicates the lower bound. It is a case of either or, and we cannot observe both within the same hour. The figure below illustrates the censoring of our dependent variable in the case of Naddvik during a three-week period in October 2021, when the power plant had a varying production pattern. The red observations show the spot price in NO5 in hours when Naddvik generated electricity, and it represents the upper bound of the water value of the plant. The lower bound is indicated by the blue observations and is the spot price when the plant was not producing.

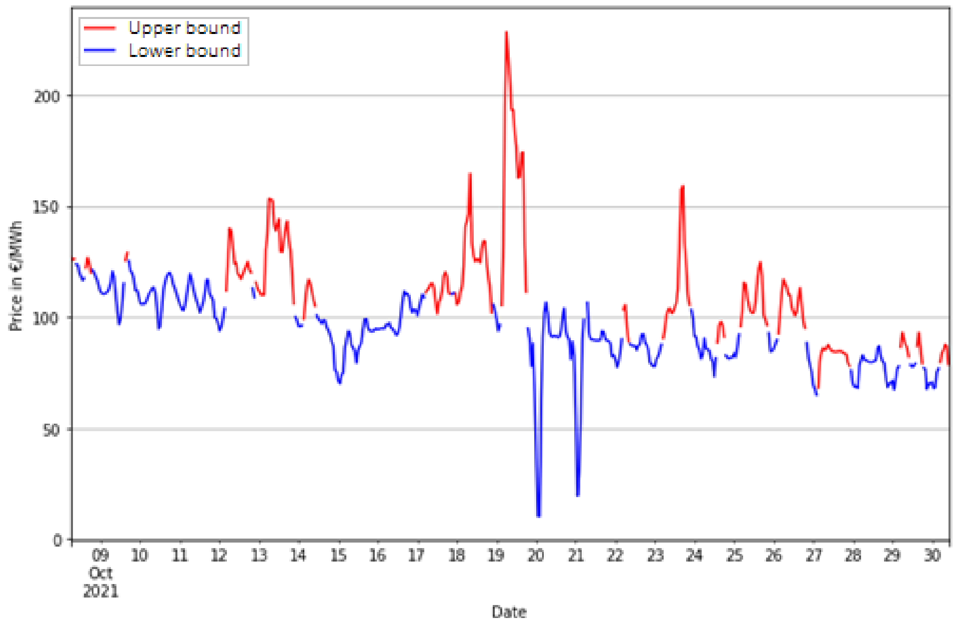

Figure 14: Double censoring of the water value in the case of Naddvik.

There are alternative models that also deal with limited dependent variables, such as interval and truncated regression models. Truncation is not an issue in our data, as we have complete data for independent variables for all hydropower producers both in periods with and without generation. Furthermore, the water value is not interval censored, but left or right censored. Therefore, we evaluated these models to not be a good fit for our data. Our choice aligns with the theory of censored regression models by Wooldridge (2010, 2021) and Hayashi (2000). Furthermore, MLE is the appropriate estimator in our case, as the Ordinary Least Square (OLS) estimator gives inconsistent estimates with censored regression models (Greene, 2002; Stock & Watson, 2016).

The general formulation of the censored regression model as stated in Hayashi (2000) is:

$$y_t^* = x_t'\beta_t + \varepsilon_t, \quad t = 1, 2, \dots, n \tag{13}$$

As our dependent variable is double censored, the response and censoring mechanism has been modified to fit the data and is defined as:

$$y_t = \begin{cases} 1 & if\ y_t^* \leq c_t \\ 0 & if\ y_t^* > c_t \end{cases} \tag{14}$$

The model aims to estimate the distribution of the unobserved latent water value y_t^* given the independent variables, at hour *t* over the time horizon *n* which is decided by the time period of our data. The independent variables, which are the market signals and other relevant variables, that we have included in the model is denoted by the vector x_t' and the coefficients that are assigned to each of the independent variables at hour *t* are given by β_t. The error term is denoted by ε_t.

The variable that we want to explain is the observable outcome variable y_t, which is a censored variable of the latent water value y_t^* (Hayashi, 2000). In our case, y_t is a binary dependent variable that indicates the hydropower producers' decision to generate electricity or not, and correspondingly takes on the value of either 1 or 0. We have defined no production as all production equal to or less than 5 MWh. The spot price is denoted by c_t. If hydropower producers bid their water value to the day-ahead market, the producers will only produce if the water value is lower than or equal to the spot price. This relationship is implied by equation 14, where we observe $y_t = 1$ when the water value is lower than or equal to the spot price, and 0 otherwise.

The specific formulation in equation 15 reveals that both the dependent variable and the independent variables in our model are log-transformed. It entails that the estimated coefficients should be interpreted as percentage change, as it is the elasticity of the independent variable.

There are a set of assumptions that must hold for the double censored regression model with the MLE to yield consistent and unbiased estimates. The assumptions will be presented with the actions taken to correct issues in the specification of our model in the next section.

The specific formulation of our double censored regression model and the response and censoring mechanism is:

$$Lat\_wv_t\_pp = Const_t\beta_t + lnDfill\_pp_t\beta_t + lnTTF_t\beta_t + lnCs_t\beta_t + lnDfill\_gas_t\beta_t + lnTemp\_city_t\beta_t + \varepsilon_t \quad (15)$$

and

$$Resp_t = \begin{cases} 1 & if\ Lat\_wv_t\_pp \leq lnP\_nox_t \\ 0 & if\ Lat\_wv_t\_pp > lnP\_nox_t \end{cases} \quad (16)$$

In the table below, we provide a description of the variable names in our specific double censored regression model.

Table 1: Description of the variables in the specific model.

Variable	Description
Lat_wv_pp	Latent water value of the hydropower plant
$Const$	Constant term
$lnDfill\_pp$	Degree of filling of the reservoirs associated with the power plant (lagged and log-transformed)
$lnTTF$	TTF day-ahead gas price (lagged and log-transformed)
$lnCs$	European carbon spot price (lagged and log-transformed)
$lnDfill\_gas$	Degree of filling of the European gas storage (lagged and log-transformed)
$lnTemp\_City$	Temperature deviation variable that indicates the difference in degrees Celsius of observed temperature to the average temperature in the previous four years in selected cities within the relevant price area (log-transformed).
$Resp$	Binary generation response variable for the power plant.
lnP_nox	Spot price in the relevant price area (log-transformed)

4.2.2. Assumptions and data transformations

For our model to yield unbiased estimates, there are particular assumptions for the double censored regression model with MLE that must be met. Based on that, we made changes to the data set and modified the model to avoid violating any of the assumptions. In this section, we present the assumptions and the steps taken to fulfil them and we discuss potential limitations. The assumptions are taken from the lecture on censored and truncated regression models by Professor Olvar Bergland in Econometric Methods (ECN301), which was given on March 29th, 2022, at NMBU.

MLE 1: Linear model

The first assumption is that the relationship between the underlying latent variable and the independent variables is linear. The assumption is crucial for the model to provide good estimates (Wooldridge, 2021). We examined a scatterplot of the dependent variable and each of the independent variables and found that the variables did not satisfy the conditions for the assumption to be met. This was addressed by log-transforming the variables, such that the assumption could be met. To perform log transformations, it was necessary to adjust negative variables.

The electricity price in NO2 contained five negative values from October 2 at 23:00 to October 3 at 03:00, ranging from -0.03 €/ MWh to -1.97 €/ MWh. We replaced these five observations with marginally positive values of 0.01 €/ MWh. Bearing in mind that there were only five hours of slightly negative prices in a period where the signals we analyse are at a stable level without major fluctuations, we argue that it does not affect the overall discussion.

MLE 2: Exogenous independent variables

Strict exogenous variables imply that the independent variables are not correlated with the error term in the model. If the assumption does not hold, the model will yield unbiased estimates and some of the variables may be explained by the error term. This initially made us believe that we had omitted variables that were affecting the degree of reservoir filling. Specifically, the temperature is a function of the demand for electricity which affects the prices and the degree of filling in the reservoirs. We thus included the colder deviation from the average temperature of the previous four years, in order to capture the abnormality in demand which we assume affects the degree of filling to some extent. The same applied to the gas price and the European gas storage filling, as these variables may be captured by the error term. It is intuitive to assume that the gas price is influenced by the gas storage filling and that the exclusion of the gas storage filling from the model could lead to omitted variable bias. Thus, the European gas storage variable was included. However, after inclusion, we found no correlation between these two variables, but we still believed that the gas storage filling may be an important variable that the hydropower producers evaluate when they calculate their water values, hence we chose to include it as a relevant variable to be analyzed. After the inclusion of these variables, we assume that we have no endogenous independent variables in the model and that the assumption holds.

MLE 3: The model is identified.

The next assumption states that the model is identified. One of the challenges when estimating non-experimental models is that we have to settle with using secondary data that has been obtained without having a specific experimental design. As a result, problems can arise when identifying the model, as the variables are not adapted to the model that is used. A prerequisite for the model to be identified is that there is no collinearity. It means that the independent variables should not have an exact linear relationship, as problems can arise by separating the effects of these variables when interpreting the coefficients. To identify if we had any variables that were perfectly collinear, we ran a correlation matrix for the included variables for each power plant [2]. For the variables that are unrelated to any particular power plant, the TTF and carbon spot have a correlation of 0.76, which indicates a slightly high correlation. Furthermore, the matrix shows that the temperature deviations between Voss and Bergen have a correlation of 0.87 and Kristiansand and Stavanger of 0.77. Furthermore, we find that several power plant-specific variables correlate to a certain extent with some market signals. These variables can be a source of misinterpretation of the coefficients in the model, but since none of the variables has an

[2] The correlation matrix is found in Appendix 4.

exactly linear relationship as the assumption states (Hill et al., 2011), we argue that the model does not contain collinearity.

Furthermore, to be able to distinguish between the effects of the variables, the model depends on enough variation and changes in the data (Hill et al., 2011). Our data set starts a few months before the gas-, carbon and electricity prices increased drastically, which indicates that it captures the entire change from a rather stable market situation up to record levels.

With no collinearity in addition to large changes between the observations in the data set, it implies that the model has been identified and that it is able to estimate the effect of change and distinguish between the independent variables.

MLE 4: Errors are normal and I.I.D

The fourth and last assumption is that the errors are independent and identically distributed (I.I.D). To address this, we used a quantile-quantile (Q-Q) plot, a histogram of the residuals, and a predicted vs residuals plot. The results reveal that for most of the power plants, the errors from the predicted model have the same probability distribution. The results from the Q-Q plots show that the errors lie in a rather straight line, with some deviations. The histogram of the residuals displays that the distribution has a symmetrical curve with density around zero with some outliers and the predicted vs residuals show no clear pattern.

For Tjodan, the Q-Q plot does not have a straight line, but some volatility. Furthermore, predicted vs residuals display a pattern and the histogram shows that the residuals are skewed, an. This may indicate that Tjodan has dependent errors and that the estimates can be biased, and it may potentially be related to structural breaks.

Furthermore, Tyin, Jostedal, and Tysso II stand out. The results show a clear pattern in the predicted vs residuals. Strong volatility in the Q-Q plot and no residuals with density around zero in the histogram. This reveals that they have dependent and not identical distributed errors, which imply biased estimates, and it may potentially be related to structural breaks.

For most power plants we have symmetrical, similar, and normally distributed residuals with constant variance across most observations, which suggests that the I.I.D assumption holds.[3]

4.2.3. Goodness-of-fit.

The goodness of fit is a calculation to evaluate the accuracy of the double censored regression model predictions against actual data. As our actual data is censored, the accuracy of the model is measured as a percentage, representing the degree to which the latent water values align with observed production data. Specifically, the model predicts when production is below 5 MW, the latent water value should be lower than the electricity price. Conversely, when production is equal to or greater than 5 MW, the latent water value should be equal to or higher than the electricity price. The goodness of fit will not be how accurate the unknown water value is to our latent water value, but whether our latent water value is on the same side of the spot price as the unknown and true water value of the power plant.

A series of true/false statements were utilized in Python. Each statement was evaluated for each hour in the data set, resulting in a total of 3672 aggregated statements with a binary outcome of either "true" or "false", denoted as 1 if "true" and 0 if "false".

Specifically, let P be a binary variable indicating whether the production in time t, noted G_t is below 5 MW (P = 1), or equal or above 5 MW (P = 0).

$$P = \begin{cases} 1 & if\ G_t < 5\ MW \\ 0 & if\ G_t \geq 5\ MW \end{cases} \tag{17}$$

Let Y be a binary variable indicating whether the latent water value in time t, noted Lat_wv_t is below the electricity price in its associated price area, noted lnP_nox (Y = 1), or above or equal lnP_nox (Y = 0).

$$Y = \begin{cases} 1 & if\ Lat\_wv_t < lnP\_nox_t \\ 0 & if\ Lat\_wv_t \geq lnP\_nox_t \end{cases} \tag{18}$$

[3] Results is visualized in Appendix 5

X is denoted as a variable indicating whether the condition P = 1 and Y = 1, or P = 0 and Y = 0 is met (X = 1) or not met (X = 0).

$$X = \begin{cases} 1 \quad if\ P = \ Y = 1 \mid 0 \\ \quad 0 \ \ if\ P \ \neq Y \end{cases} \tag{19}$$

The number of statements in X that were evaluated as "true" were counted and divided by the total number of observations in the data set. The result was then multiplied by 100 to obtain a percentage.

$$\text{Goodness of fit:} \quad \frac{Amount\ of\ X = 1}{3672} \times 100 = \ \% \tag{20}$$

A high score indicates that we can be more confident in the results the model yields, and that the latent reservations price with its trends in the predicted model are assumed to lie on the same side of the electricity price. A worse fit indicates that the model is not able to predict the latent water value as well as with the selected market signals and that there may be other factors that influence the prediction. In addition, we have a possible bias, as pointed out in section 4.1.2. It is assumed that the producers produce solely for the day-ahead market when the water value is above or equal to the spot price and save the water when the water value is below. If they produce in other markets with different price signals than the spot price or if they are downregulated in the reserve market, the goodness of fit will yield incorrect estimates.

4.2.4. Structural break

To analyze the timing of the hydropower producer's reaction to the market signals, identifying possible structural breaks in the time series can serve as an indication of a change in the expectations with respect to the market signals. A structural break refers to an abrupt change at a specific point in a time series, creating a noticeable shift between two series (Levendis, 2018). To identify potential structural breaks in our time series data, we applied the rolling window method to the double censored regression model. The start date was set to the 1st of August, with a step of

24 hours. The process was repeated every 24 hours until all the data were analyzed up to the 1st of January 2022, which resulted in a total of 154 iterations.

In our analysis, we tested estimation periods consisting of the data from six, five and four weeks prior to the start date to assess if the structural break became more prominent or weakened as the estimation period was shortened. To be able to perform the analysis, we expanded our dataset to include the data from the 20th of June 2021 and performed all necessary transformations as described in the data sections for each variable.

Initially, the model was estimated solely on the constant term, which provided a direct estimation of the latent water value, unaffected by any of the market signals. A structural break in the constant term indicates a sudden change in the latent water value of the hydropower producer and may indicate that the producer revised the fundamental model at that point in time. For the power plants where a structural break was identified, we included the relevant market signals in the model and applied the rolling window method with the same estimation period and time steps. This allowed us to assess if any of the structural breaks in the latent water value could be compatible with a possible break in the market signals. If a break in the latent water value occurred at the same time as a break in the market signals, it could be an indication that the hydropower producer reassessed the fundamental model due to a change in expectations with respect to the market signals.

5. Results and discussion

In this chapter, we present the results for each of the 17 hydropower plants and provide discussions to address the findings and answer the research questions. First, we present the goodness-of-fit results. Thereafter, we present the estimates from the double censored regression model, with two graphs. The graph on the left-hand side illustrates the development in the estimated log-transformed latent water value and the significant market signals. The significance level is set as 5 %. The graph on the right-hand side illustrates the latent water value and electricity price on the y-axis, and the actual production of the power plant on the z-axis. The production is included to illustrate how well the model fits the data. If the model fits well, the figure will show that the hydropower producer produces when the latent water value is below the electricity price and will refrain from production when the water value is above the electricity price. The produced amounts vary between the power plants; hence the scale of the z-axis differs. Thereafter, the structural break results are presented. We used a four-week estimation period, as it gave the most prominent indications of structural breaks relative to a longer estimation period. Two graphs are included, where the left show the structural breaks in the latent water value and the one to the right illustrates the breaks in the market signals.

5.1. Goodness-of-fit.

Table 2: Goodness-of-fit results.

Goodness of Fit for NO2

Power Station	Percent Fit
Tysso II	98.07 %
Holen III	87.66 %
Duge	85.84 %
Saurdal	84.72 %
Sundsbarm	83.44 %
Songa	81.24 %
Skjerka	81.24 %
Holen I-II	76.88 %
Tjodan	73.39 %
Lysebotn II	72.82 %

Goodness of Fit for NO5

Power Station	Percent Fit
Tyin	93.22 %
Aurland III	88.70 %
Leirdøla	87.01 %
Sy-Sima	82.98 %
Naddvik	81.37 %
Lang-Sima	73.99 %
Jostedal	7.00 %

The tables above show the goodness-of-fit results for the power plants in price areas NO2 and NO5. In our sample, Tysso II, Tyin and Jostedal stand out from the rest due to significantly less variation in their production patterns. Consequently, Tysso II and Tyin have very high values, and Jostedal has a very small value of 7 %. The range of goodness-of-fit values for all the remaining power plants, which have greater variation in the production pattern, is between 72,82 % and 88,7 %. Among these plants, Lysebotn II has the lowest value and Aurland III the highest. This range indicates the variation in the alignment of the model's latent water value estimates with the true water values for these specific power plants in the period of interest. Thus, the overall goodness of fit varies at 91,07 %, and for the powerplants with a varying production pattern at 15,88 %. The results indicate that we can be confident that the model manages to capture the true trend in the water values for most of the power plants.

5.2. Double censored regression model

5.2.1. Duge

Table 3: Model estimates for Duge.

Double Censored Regression Model

Variable	Est Coef	Std Err	z	P>|z|
LnCs	0.0702	0.0455	1.54	0.12
lnTtf	0.1555	0.0215	7.23	0.00
lnDfill_Duge	-1.6173	0.0377	-42.91	0.00
lnDfill_gas	-0.4212	0.0354	-11.88	0.00
lnTemp_kristiansand	0.0071	0.0052	1.36	0.17
lnTemp_stavanger	0.0013	0.0058	0.22	0.82
const	11.4059	0.3267	34.91	0.00

All independent variables are significant at 1 %, except carbon spot and temperature deviation variables. A 1 % increase in the gas price is associated with a 0,15 % increase in the latent water value, everything else held constant. For a 1 % increase in the reservoir filling or the gas storage filling the latent water value responds with a change of -1,62 % and -0,42 %, respectively. The latent water value is most sensitive to a change in the reservoir filling. Standard errors are small, indicating high precision in estimating the sample mean.

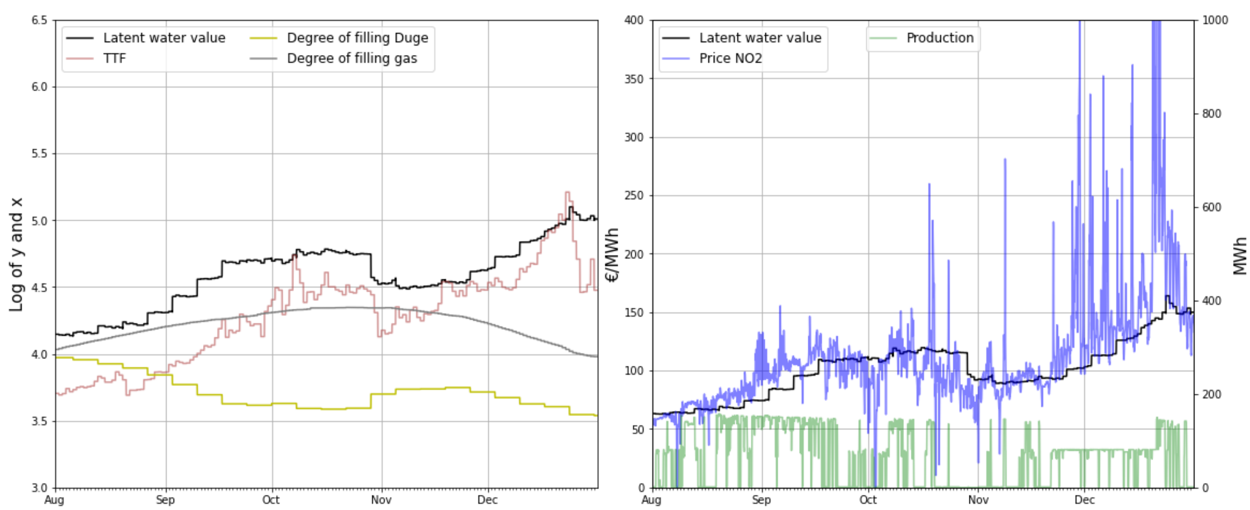

Figure 15: Latent water value of Duge, incl. market signals, NO2 price and production.

The latent water value of Duge had a generally increasing trend in the period, with a peak in December. When entering the period, the latent water value was 63,2 €/ MWh, the exit value was 149,9 €/ MWh and the maximum latent water value in the period was 16,9 €/ MWh. In the figure to the left, the water value increased as the gas price increased, and the reservoir filling and gas storage filling decreased. In the figure to the right, the latent water value followed the trend of the NO2 electricity price, and they intersected frequently. Duge produced throughout most of the period, except for a period in late October when the latent water value exceeded the electricity price.

5.2.2. Holen I-II

Table 4: Model estimates for Holen I-II.

Double Censored Regression Model

Variable	Est Coef	Std Err	z	P>|z|
LnCs	0.1878	0.1460	1.29	0.20
lnTtf	-0.5522	0.0700	-7.89	0.00
lnDfill_Holen	-2.7967	0.2738	-10.22	0.00
lnDfill_gas	-0.1395	0.1525	-0.91	0.36
lnTemp_kristiansand	-0.0083	0.0178	-0.47	0.64
lnTemp_stavanger	-0.1400	0.0208	-6.74	0.00
const	18.4470	1.3745	13.42	0.00

The gas price, reservoir filling and temperature deviation variable for Stavanger are significant at 5 %. If the gas price increase by 1 %, the latent water value responds by decreasing -0,55 %. For a 1 % increase in the reservoir filling of Holen I-II, the water value decrease by -2,8 %. The latent water value is most sensitive to a change in the reservoir filling. Standard errors are small.

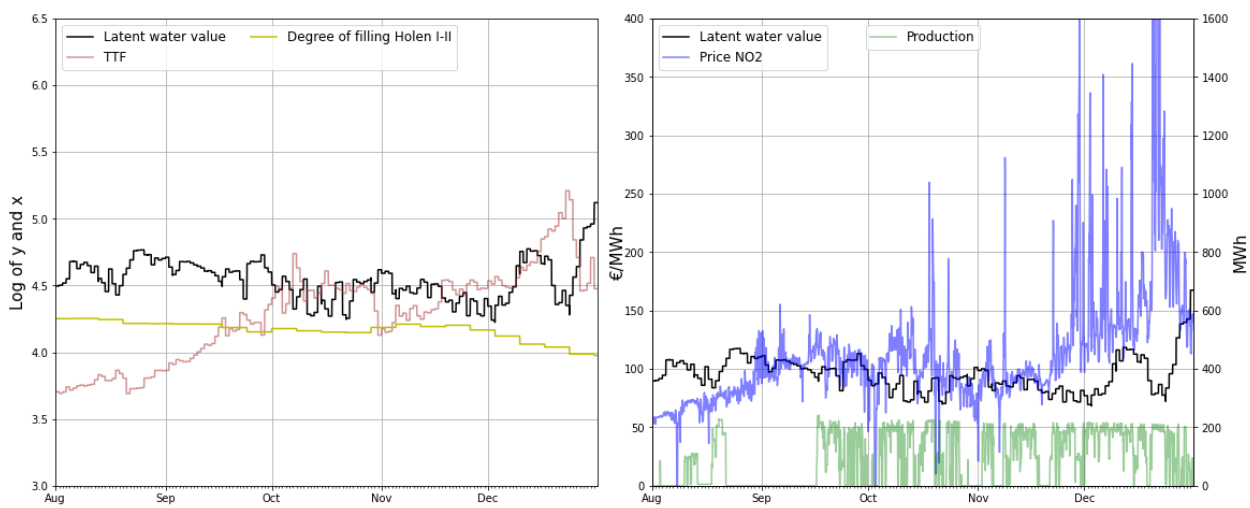

Figure 16: Latent water value of Holen I-II, incl. market signals, NO2 price and production.

The latent water value had a slightly decreasing trend throughout the period except for December when it increased, had a drop, and then continued to increase until the end of the year. In the figure to the left, the latent water value decreased with the increasing gas price and slowly decreasing reservoir filling until December. Afterward, the latent water value increased as the reservoir filling decreased more rapidly. To the right the latent water value shifted between being above, on and under the electricity price. The entry latent water value was 89,6 €/ MWh, the exit value was 167,4 €/ MWh and the peak value was 163,9 €/ MWh. Holen I-II refrained from producing in the start until mid-September as the electricity price was below the water value.

5.2.3. Holen III

Table 5: Model estimates for Holen III.

Double Censored Regression Model

Variable	Est Coef	Std Err	z	P>|z|
LnCs	-0.7413	0.0725	-10.22	0.00
lnTtf	-0.0940	0.0293	-3.21	0.00
lnDfill_HolenIII	-0.6378	0.0997	-6.40	0.00
lnDfill_gas	-2.2083	0.1360	-16.24	0.00
lnTemp_kristiansand	-0.1306	0.0107	-12.17	0.00
lnTemp_stavanger	0.1058	0.0113	9.34	0.00
const	20.2692	0.5563	36.44	0.00

All independent variables are significant at a 1 % level. A 1 % increase in the carbon spot or the gas price is associated with a respectively -0,74 % or -0,09 % decrease in the latent water value, everything else held constant. A 1 % increase in the reservoir filling or gas storage filling is associated with a respectively -0,63 % and -2,20 % decrease in the latent water value. The latent water value is most sensitive to a change in the European gas storage filling. The standard errors are small.

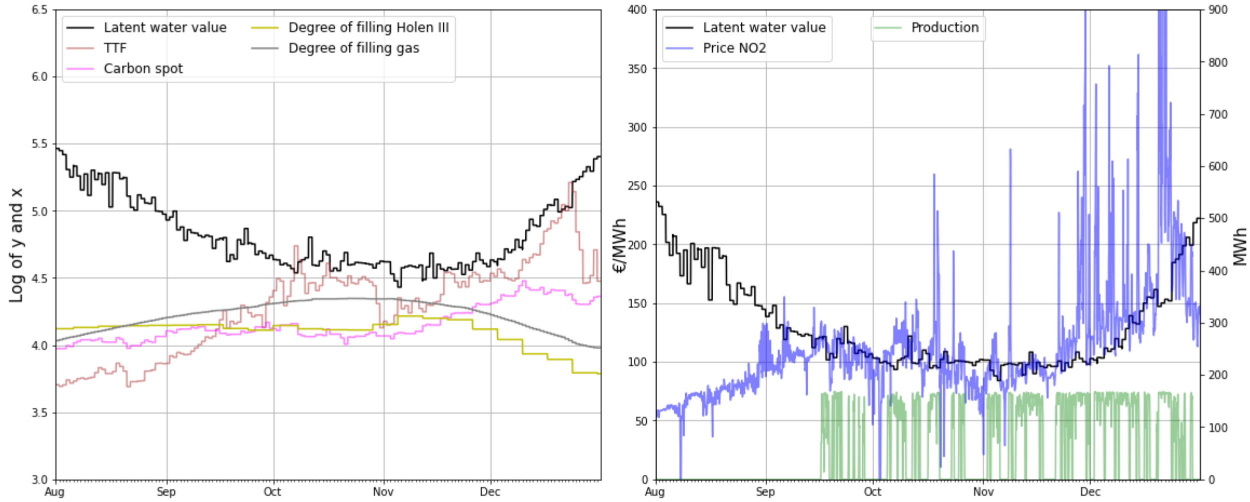

Figure 17: Latent water value of Holen III, incl. market signals, NO2 price and production.

Holen III's latent water value had a decreasing trend until mid-November and increased for the rest of the period. In the figure to the left, the latent water value decrease as all market signals increase. Furthermore, the latent water value increase as the direction of the gas storage filling and reservoir filling turn in November and starts to decrease. In the figure to the right, the latent water value is above the spot price until mid-September. Thereafter, the latent water value moved together with the spot price until the peak in December. The entry and maximum latent water value in the period was 235,9 €/ MWh, and the exit value was 222,1 €/ MWh. The production pattern is as expected with regard to the position of the latent water value relative to the spot price. There is a long period of non-production until mid-September.

5.2.4. Lysebotn II

Table 6: Model estimates for Lysebotn II.

Double Censored Regression Model

Variable	Est Coef	Std Err	z	P>|z|
LnCs	-1.0769	0.4960	-2.17	0.03
lnTtf	0.6169	0.1302	4.74	0.00
lnDfill_Lysebotn II	-0.8835	0.1374	-6.43	0.00
lnDfill_gas	-1.4120	0.3676	-3.84	0.00
lnTemp_kristiansand	-0.4657	0.0868	-5.36	0.00
lnTemp_stavanger	0.3106	0.0703	4.42	0.00
const	16.0734	3.1468	5.11	0.00

All independent variables are significant at a 5 % level. For a 1 % increase in the carbon spot the latent water value of Lysebotn II decrease by -1,1 %, everything else held constant. A 1 % increase in the gas price leads to an increase of 0,6 % in the latent water value. With a 1 % increase in the reservoir filling or the gas storage filling the latent water value change by -0,88 % and-1,4 % respectively. The latent water value is most sensitive to a change in the gas storage filling. The standard errors are small.

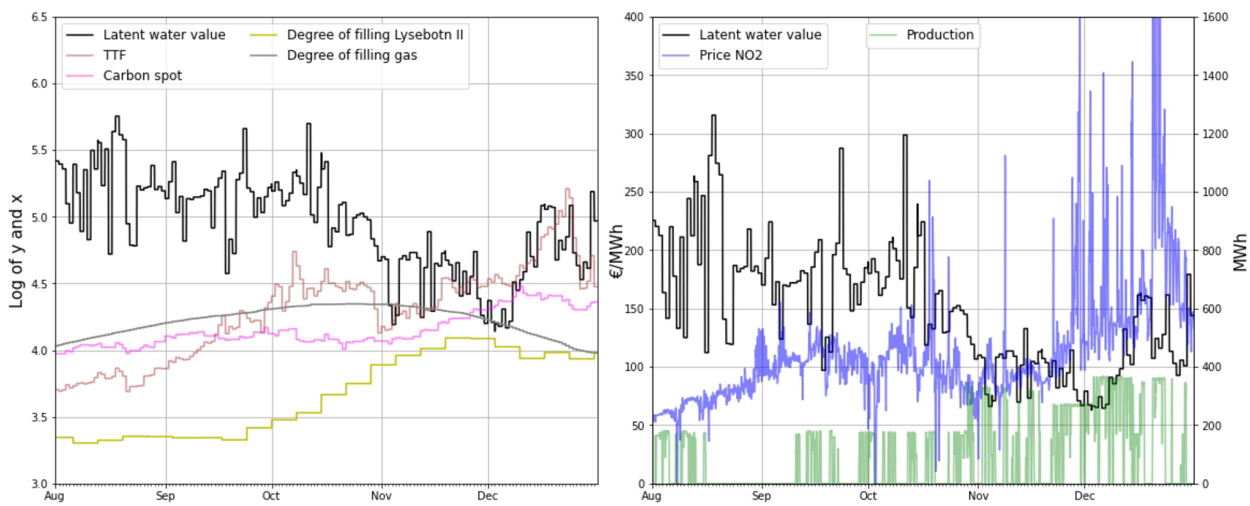

Figure 18: Latent water value of Lysebotn II, incl. market signals, NO2 price and production.

Lysebotn II's latent water value had a decreasing trend until December and an increasing trend through December. In the figure to the left, the latent water value decreases corresponding to the increasing carbon spot price, reservoir filling and gas storage filling. In December, the latent water value rise with the increasing gas price and the decreasing reservoir filling, gas storage filling and carbon spot. In the figure to the right, the latent water value moves above the NO2 spot price until mid-November and below through the rest of the year. The entry value was 225,5 €/ MWh, the exit value was 143,9 €/ MWh and the maximum value was 315,4 €/ MWh. Lysebotn II refrained from producing or produced lower amounts until November and produced more after this point. The production pattern deviates from the expectations due to production when the latent water value was above the spot price.

5.2.5. Saurdal

Table 7: Model estimates for Saurdal.

Double Censored Regression Model

Variable	Est Coef	Std Err	z	P>|z|
LnCs	0.4496	0.2059	2.18	0.03
lnTtf	-0.7708	0.1091	-7.07	0.00
lnDfill_Saurdal	-2.6205	0.2571	-10.19	0.00
lnDfill_gas	0.9771	0.1654	5.91	0.00
lnTemp_kristiansand	-0.2718	0.0317	-8.58	0.00
lnTemp_stavanger	0.0048	0.0271	0.18	0.86
const	12.2706	1.9328	6.35	0.00

All variables are significant at 5 % except the temperature deviation variable for Stavanger. A 1 % increase in the carbon spot price is associated with a 0,45 % increase in the latent water value, everything else held constant. A 1 % increase in the reservoir filling is associated with a -2,6 % decrease in the latent water value. Similarly, A 1 % increase in the gas price or the gas storage filling is associated with a -0,77 % decrease and a 0,98 % increase in the latent water value. The latent water value is most sensitive to a change in the reservoir filling variable, indicated by the size of the coefficient relative to the other estimated coefficients. The standard errors are small.

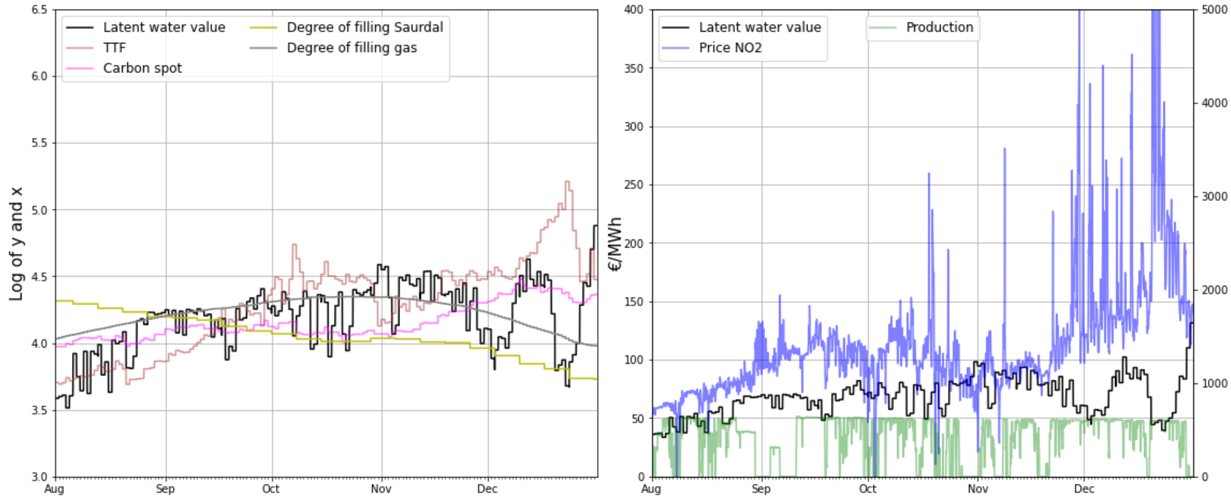

Figure 19: Latent water value of Saurdal, incl. market signals, NO2 price and production.

Saurdal's latent water value had a generally increasing trend throughout the period, with some volatile changes in December. To the left, the latent water value increase with the increasing carbon spot and gas storage filling, as well as with the decreasing reservoir filling. The volatile changes in the latent water value in December correspond to the rise in the gas price, the decreasing gas storage filling, and the more rapidly decreasing reservoir filling. In the figure to the right, the latent water value moved below the NO2 spot price for most of the period. The latent water value was 36 €/ MWh, and the exit and maximum value was 131,5 €/ MWh. The production pattern is as expected regarding the position of the latent water value relative to the spot price except in September when they refrained from producing even though the water value was below the market price.

5.2.6. Skjerka

Table 8: Model estimates for Skjerka.

Double Censored Regression Model

Variable	Est Coef	Std Err	z	P>|z|
LnCs	-0.3366	0.0707	-4.76	0.00
lnTtf	1.0292	0.0274	37.53	0.00
lnDfill_Skjerka	-0.2582	0.0103	-25.13	0.00
lnDfill_gas	-0.6479	0.0536	-12.08	0.00
lnTemp_kristiansand	0.0025	0.0088	0.28	0.78
lnTemp_stavanger	-0.0029	0.0097	-0.30	0.76
const	5.3342	0.3769	14.15	0.00

All independent variables are significant at 5 % apart from the temperature deviation variables. The estimated coefficient implies that for a 1 % increase in the carbon spot, the latent water value decrease by -0,34 %, everything else is held constant. For a 1 % increase in the gas price the latent water value increase by 1,03 %. With a 1 % increase in the reservoir filling and gas storage filling, the latent water value decrease by -0,26 % and -0,65 % respectively. The latent water value is most sensitive to changes in the gas price. The standard errors are small.

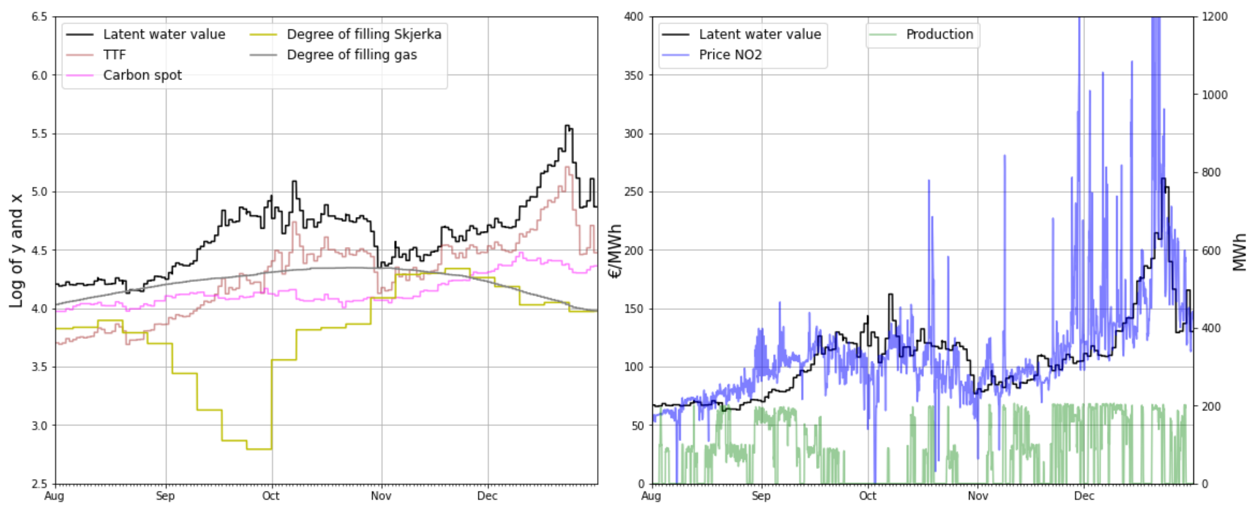

Figure 20: Latent water value of Skjerka, incl. market signals, NO2 price and production.

The latent water value had a generally increasing trend in the period of interest, with a peak in December. In the figure to the left, the latent water value increase corresponds to the increasing gas price and declining reservoir filling, as well as the declining gas storage filling in December. In the figure to the right, the latent water value moves together with and intersects the NO2 spot price throughout the period. The latent water value when entering the period was 67,1 €/ MWh, the exit value was 130 €/ MWh, and the maximum value was 261,2 €/ MWh. The production pattern is as expected with regard to the position of the latent water value relative to the spot price.

5.2.7. Songa

Table 9: Model estimates for Songa.

Double Censored Regression Model

Variable	Est Coef	Std Err	z	P>|z|
LnCs	-2.0375	0.2112	-9.65	0.00
lnTtf	1.5288	0.0877	17.43	0.00
lnDfill_Songa	0.3532	0.1499	2.36	0.02
lnDfill_gas	0.4129	0.1118	3.69	0.00
lnTemp_kristiansand	-0.0682	0.0205	-3.33	0.00
lnTemp_stavanger	0.0390	0.0218	1.79	0.07
const	3.3463	0.9716	3.44	0.00

All the independent variables are significant at a 5 % level except the temperature deviation variable for Stavanger. The model estimates suggest that for a 1 % increase in the gas price, the latent water value increase by 1,53 %, everything else held constant. With a 1 % increase in the carbon spot price, the latent water value decrease by 2,04 %. Furthermore, for a 1 % increase in the reservoir filling or gas storage filling, the latent water value increase with respectively 0,35 % and 0,41 %. The latent water value is most sensitive to a change in the carbon spot. The standard errors are small.

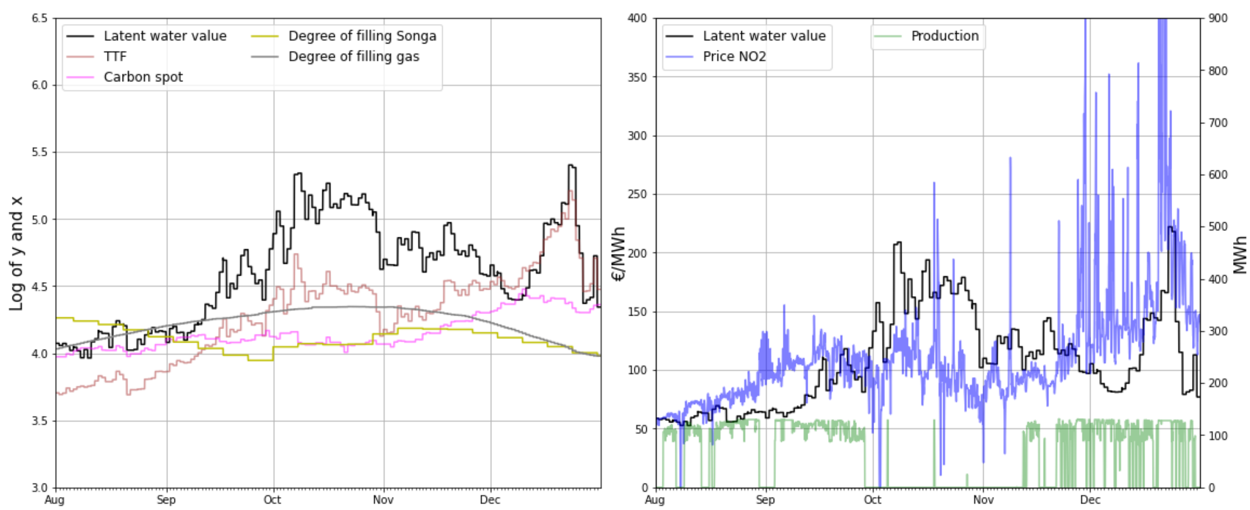

Figure 21: Latent water value of Songa, incl. market signals, NO2 price and production.

Songa's latent water value shows a generally increasing trend, except for in November. In the figure to the left, the latent water value increase corresponds to the increasing gas price as well as to the rising reservoir and gas storage filling until November. In December, the increase in the latent water value corresponds to rising gas prices. In the figure to the right, the latent water value is below the spot price for most of the period, except in October and November. The entry value was 58,7 €/ MWh, the exit value was 77 €/ MWh and the maximum latent water value in the period was 222 €/ MWh during the peak in December. The production pattern is mostly as expected with regard to the position of the latent water value relative to the spot price. We observe that Songa had hardly any production in the mid of the period.

5.2.8. Sundsbarm

Table 10: Model estimates for Sundsbarm.

Double Censored Regression Model

Variable	Est Coef	Std Err	z	P>|z|
LnCs	-0.4533	0.0721	-6.29	0.00
lnTtf	0.6389	0.0263	24.27	0.00
lnDfill_Sundsbarm	-0.8607	0.0354	-24.33	0.00
lnDfill_gas	-0.5729	0.0547	-10.46	0.00
lnTemp_kristiansand	-0.0479	0.0091	-5.24	0.00
lnTemp_stavanger	0.0965	0.0102	9.44	0.00
const	9.6908	0.4219	22.97	0.00

All the independent variables are significant at a 1 % level. The estimated coefficient indicates that for 1 % in the carbon spot price, the latent water value decrease by -0,45 %, everything else held constant. For a 1 % increase in the gas price, the latent water value responds by increasing 0,64 %. The latent water value is reduced by -0,86 % and -0,57 % for a 1 % increase in the reservoir filling or the gas storage filling respectively. The latent water value is most sensitive to a change in the reservoir filling. Standard errors are small.

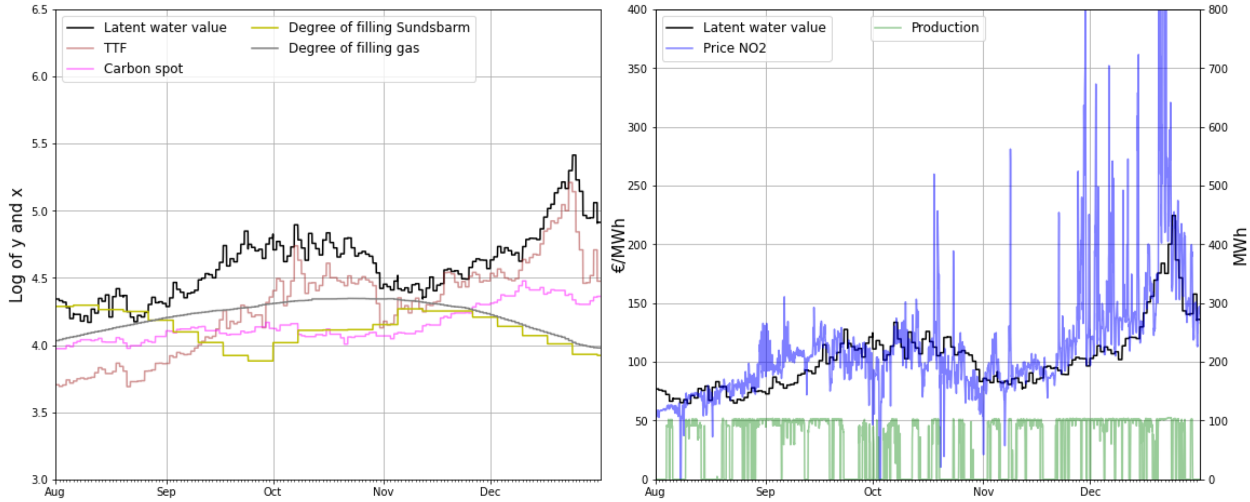

Figure 22: Latent water value of Sundsbarm, incl. market signals, NO2 price and production.

The graph on the right illustrates that Sundsbarm enters the period at 79,9 €/ MWh and is stably below the spot price until the end of September where it stabilizes before a decreasing trend in line with the spot price at the end of October. Furthermore, the latent water value starts an increasing trend towards the peak price of 224,5 €/ MWh at the end of December in line with the increasing trend in the spot price.

The graph on the left displays that the TTF increases in line with the increase in the latent water value until the local peak in the TTF in October. At the same time, the degree of filling decreases. In December, the direction of the estimated coefficient becomes more prominent, where gas storage and degree of filling in Sundsbarm have a downward trend, while TTF increases together with the latent water value. Carbon spot has a slightly downward trend when the latent water value has its strongest increase, in line with the estimated coefficient.

5.2.9. Tjodan

Table 11: Model estimates for Tjodan.

Double Censored Regression Model

Variable	Est Coef	Std Err	z	P>|z|
LnCs	-7.5016	0.9922	-7.56	0.00
lnTtf	2.6671	0.2727	9.78	0.00
lnDfill_Tjodan	0.3725	0.0975	3.82	0.00
lnDfill_gas	-2.2476	0.4815	-4.67	0.00
lnTemp_kristiansand	-0.3553	0.0823	-4.32	0.00
lnTemp_stavanger	-0.1102	0.0835	-1.32	0.19
const	33.6942	4.5630	7.38	0.00

All the estimated coefficients apart from temperature deviation in Stavanger are significant at the 1 % level. Carbon spot has the highest estimated coefficient, where the latent water value is reduced by 7,5 % when carbon spot increases by 1 %, given that other variables are held constant. Furthermore, the model indicates an increase in the latent water value by 2,6 %, when TTF increase by 1 %, holding other variables constant. A 1 % increase in the degree of filling and gas storage leads to a corresponding increase of 0,37 % and a -2,24 % decrease in the latent water value.

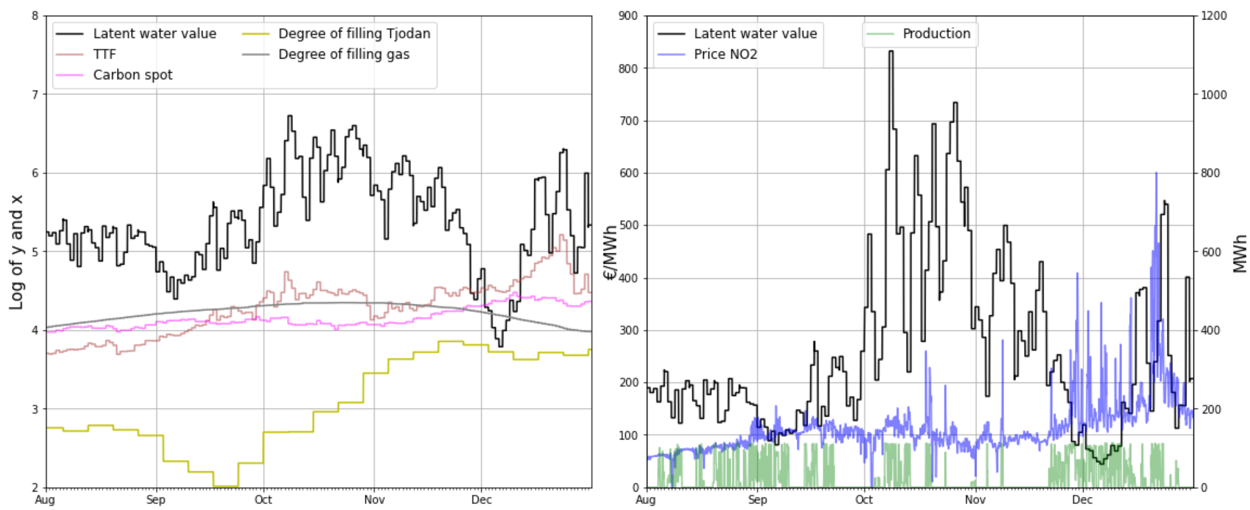

Figure 23: Latent water value of Tjodan, incl. market signals, NO2 price and production.

As seen in the graph to the left, the latent water value increases considerably in December, parallel with the increase in TTF prices, at the same time as the carbon spot starts a downward trend, which is in line with the estimated coefficients. In the graph on the right, the latent water value enters the period at a relatively high level with 189,7 €/ MWh, compared to the NO2 price, and shows a decreasing trend until September where it fluctuates but has an increasing trend until October where it also hits the peak price of 832 €/ MWh.

The latent water value is approximately above the NO2 price throughout that period, even though Tjodan produces in periods. This gives the model a fit of 73,39 %. The latent water value starts a downward trend, which persists until the start of December, and dips below the NO2 price, which results in a relatively stable production level.

5.2.10. Tysso II

Table 12: Model estimates for Tysso II.

Double Censored Regression Model

Variable	Est Coef	Std Err	z	P>|z|
LnCs	-106.9608	46.0731	-2.32	0.02
lnTtf	32.8562	13.7061	2.40	0.02
lnDfill_TyssoII	17.2452	11.9721	1.44	0.15
lnDfill_gas	-16.0655	10.7917	-1.49	0.14
lnTemp_kristiansand	-0.0876	1.1490	-0.08	0.94
lnTemp_stavanger	0.8608	1.1190	0.77	0.44
const	280.9245	144.8752	1.94	0.05

According to the model estimates, the only two significant independent variables influencing the latent water value are the carbon spot and the TTF. The estimated coefficients indicate a negative relationship between the carbon spot and the latent water value. Furthermore, the estimates suggest that there is a positive relationship between the TTF and the latent water value. The magnitude of the estimates is volatile and disproportionate compared to the estimates of most of the other plants included in the study. Furthermore, the standard errors are large, indicating imprecise estimates.

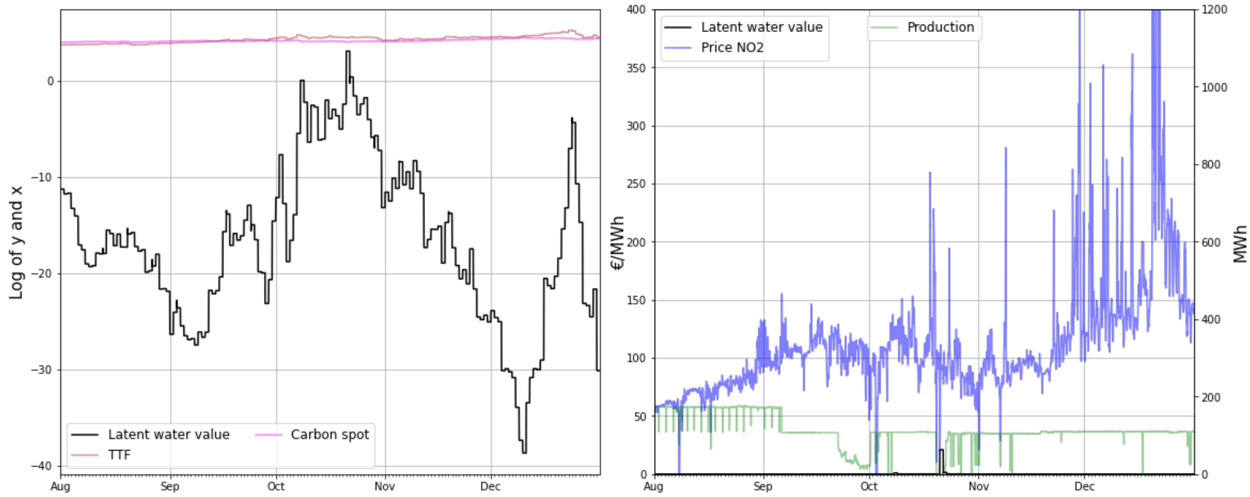

Figure 24: Latent water value of Tysso II, incl. market signals, NO2 price and production.

The graph to the left show that the latent water value varied a lot over the period, and that almost every value lies on the negative side of the scale. The magnitude of the latent water value is extreme compared to the scale of the independent variables in the graphs, which makes the interpretation of the latent water value against the market signals more challenging.

In the graph on the right, Tysso II produced approximately nonstop throughout the period, while the latent water value is below the spot price, which gives the model a goodness of fit of 98,07 %.

5.2.11. Aurland III

Table 13: Model estimates for Aurland III.

Double Censored Regression Model

Variable	Est Coef	Std Err	z	P>|z|
LnCs	-1.2879	0.0737	-17.48	0.00
lnTtf	0.5371	0.0331	16.23	0.00
lnDfill_Aurland III	-1.3213	0.0640	-20.64	0.00
lnDfill_gas	0.1595	0.0636	2.51	0.01
lnTemp_bergen	0.0480	0.0130	3.68	0.00
lnTemp_voss	0.0234	0.0112	2.10	0.04
const	12.1948	0.4387	27.80	0.00

The estimated coefficients indicate that a 1 % increase in the degree of filling leads to a -1,32 % decrease in the latent water value, holding all other variables constant. A 1 % increase in the carbon spot price is associated with a -1,29 % decrease in the latent water value. A 1 % increase in the gas price or the gas storage filling is associated with a 0,54 % and 0,16 % increase in the latent water value. All estimated coefficients are significant at 5 %, with small standard errors.

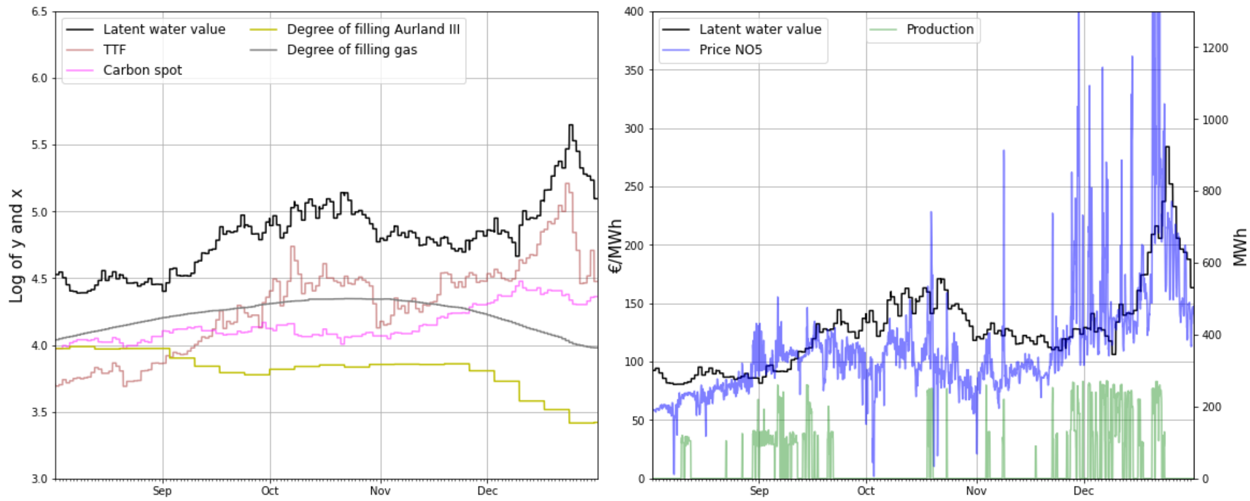

Figure 25: Latent water value of Aurland III, incl. market signals, NO5 price and production.

In the graph to the left, the latent water value had a modest upward trend in September, aligning with the increase in the gas price and the gas storage filling, which is consistent with the estimated coefficients. Thereafter, the latent water value followed the decline in the gas price towards the end of October, followed by a decrease in the gas storage filling. In November, the latent water value had a relatively stable and slightly declining trend, while the carbon price reached its peak during the same period. Furthermore, in December there was a substantial increase in the gas price with a corresponding rise in the latent water value, while the carbon price declined, providing support for the estimated coefficients.

Aurland III entered August with a latent water value of 92,1 €/ MWh, slightly above the electricity price, which lead them to refrain from production. However, as the electricity price increased in September, the water value was adjusted and remained constantly above the electricity price from mid-September to early December, with occasional peaks in the spot price where the power plant produced. Furthermore, the graph shows that the latent water value had a steep increase toward the peak price of 284 €/ MWh at the end of December.

5.2.12. Jostedal

Table 14: Model estimates for Jostedal.

Double Censored Regression Model

Variable	Est Coef	Std Err	z	P>|z|
LnCs	-37.3556	13.9697	-2.67	0.01
lnTtf	24.3061	8.4680	2.87	0.00
lnDfill_Jostedal	0.8117	2.6903	0.30	0.76
lnDfill_gas	-13.5823	5.3439	-2.54	0.01
lnTemp_bergen	-0.6455	0.3453	-1.87	0.06
lnTemp_voss	2.1151	0.8027	2.64	0.01
const	113.7076	45.8432	2.48	0.01

All the estimated coefficients are significant at a 1 % level, except the reservoir filling of Jostedal and the temperature deviation variable for Bergen. The model estimates abnormal values for the coefficients, except for the reservoir filling which is similar to the coefficients of the other hydropower plants. The standard errors are large, indicating imprecise estimates.

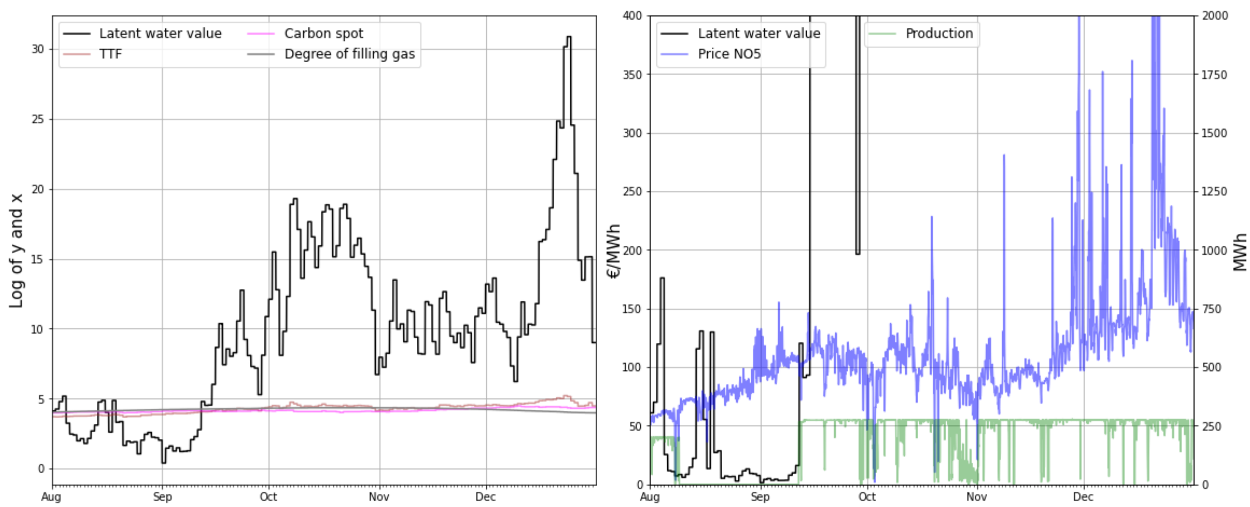

Figure 26: Latent water value of Jostedal, incl. market signals, NO5 price and production.

The graphs to the left show that the latent water value was at a disproportionate scale relative to the independent variables and the electricity price. The graph to the right show that Jostedal refrained from producing from mid-August to mid-September, even though the latent water value was below the electricity price in NO5. Furthermore, Jostedal produced almost constantly throughout the rest of the year, which means that the true water value of Jostedal was below the electricity price from mid-September until the end of the year, and the latent water value were at the opposite side of the electricity price, hence only 7 % goodness-of-fit.

5.2.13. Lang-Sima

Table 15: Model estimates for Lang-Sima.

Double Censored Regression Model

Variable	Est Coef	Std Err	z	P>|z|
LnCs	0.0056	0.1146	0.05	0.96
lnTtf	0.5415	0.0373	14.51	0.00
lnDfill_LangSima	0.1001	0.0727	1.38	0.17
lnDfill_gas	-1.3573	0.1038	-13.07	0.00
lnTemp_bergen	-0.2424	0.0231	-10.50	0.00
lnTemp_voss	0.1676	0.0203	8.26	0.00
const	7.7097	0.6623	11.64	0.00

The estimated coefficient for carbon spot and degree of filling in Lang-Sima are not statistically significant in our sample data. The model estimates that a 1 % increase in the gas price leads to a 0,54 % increase in the latent water value, with all other variables held constant. Also, a 1 % increase in degree of gas storage filling leads to a decrease in the latent water value by -1,36 %. The standard errors imply that the TTF gas price is a more precise fit than the degree of gas storage filling.

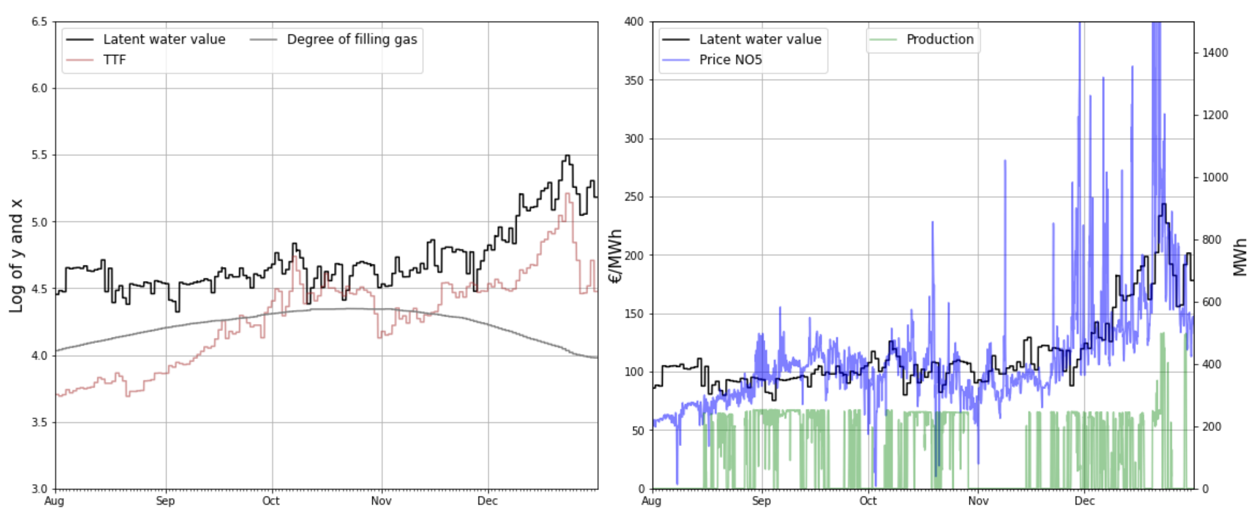

Figure 27: Latent water value of Lang-Sima, incl. market signals, NO5 price and production.

The graph to the left shows that the latent water value increased corresponding to an increase in the gas price at the start of the period. In November, the latent water value had an upward trend towards the peak late in December, corresponding to an increase in gas prices along with the decreasing trend in gas storage. In the graph to the right, Lang-Sima entered the period above the spot price with a latent water value of 86 €/ MWh, which resulted in no production. Thereafter, the latent water value moved together with and intersected the spot price frequently until November where it remained slightly above the NO5-price which resulted in no production for a two-week before it moved together with the spot price towards a peak in December with a latent water value of 243,6 €/ MWh.

5.2.14. Leirdøla

Table 16: Model estimates for Leirdøla.

Double Censored Regression Model

Variable	Est Coef	Std Err	z	P>|z|
LnCs	0.3853	0.0728	5.30	0.00
lnTtf	0.5409	0.0296	18.29	0.00
lnDfill_Leirdøla	-2.0601	0.1007	-20.45	0.00
lnDfill_gas	-0.0742	0.0130	-5.71	0.00
lnTemp_bergen	1.4084	0.1208	11.66	0.00
lnTemp_voss	0.1200	0.0140	8.58	0.00
const	2.7903	0.4207	6.63	0.00

All estimated coefficients are significant at a 1 % level. The estimated coefficients indicate that an increase in the degree of reservoir filling of Leirdøla by 1 % is associated with a -2,1 % decrease in the latent water value, with everything else held constant, while a 1 % increase in the European gas storage filling is associated with -0,07 % decrease in the latent water value. An increase in the gas price or the carbon spot is associated with an increase of respectively 0,54 % and 0,39 % in the latent water value, everything else held constant. Standard errors are small, indicating precise estimates.

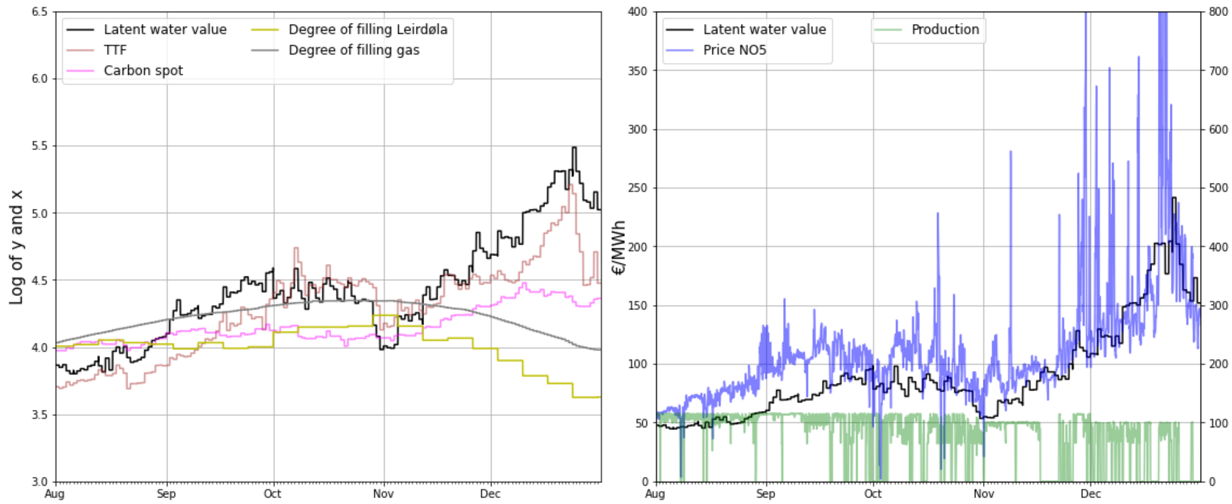

Figure 28: Latent water value of Leirdøla, incl. market signals, NO5 price and production.

In the figure to the left, the latent water value had a generally increasing trend in the period with a peak in December. In the second half of the period, the latent water value increased following an increase in the gas- and carbon spot prices and a decrease in the gas storage filling and Leirdøla's reservoir filling. In the graph to the right, the latent water value entered the period at a value of 47,7 €/ MWh. Thereafter, it increased gradually during the autumn, dropped at the end of October, and increased in November before it peaked around the 21st of December at 241,5 €/ MWh. The latent water value was generally lower than the electricity price in August and September, in contrast to later in the period, where we observe that it more regularly exceeded the spot price.

5.2.15. Naddvik

Table 17: Model estimates for Naddvik.

Double Censored Regression Model

Variable	Est Coef	Std Err	z	P>|z|
LnCs	0.6458	0.0657	9.83	0.00
lnTtf	0.7524	0.0262	28.75	0.00
lnDfill_Naddvik	-1.2231	0.0317	-38.53	0.00
lnDfill_gas	1.3124	0.0657	19.98	0.00
lnTemp_bergen	0.0854	0.0139	6.15	0.00
lnTemp_voss	-0.0434	0.0132	-3.28	0.00
const	-2.2119	0.3789	-5.84	0.00

All estimated coefficients are significant at a 1 % level. A 1 % increase in the gas storage filling is associated with a 1,31 % increase in the latent water value, everything else held constant. A 1 % increase in Naddvik's degree of reservoir filling is associated with a -1,22 % decrease in the latent water value. A 1 % increase in the gas price or the carbon spot price is associated with a 0,75 % and 0,65 % increase in the latent water value. Standard errors are small, which indicates precise estimates.

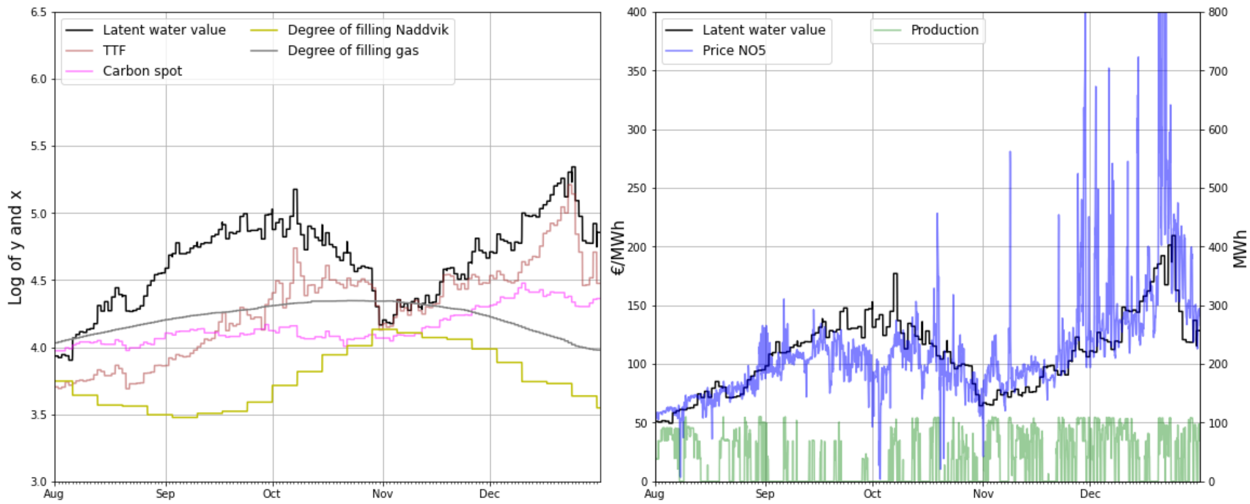

Figure 29: Latent water value of Naddvik, incl. market signals, NO5 price and production.

The graph to the left show that the latent water value increased until mid-October, decreased until November, and increased towards a peak in December. The increase in the latent water value at the start of the period corresponds to the increase in the TTF, carbon spot, and gas storage, at the same time as the degree of filling in Naddvik decreased. In the second half of the period, the latent water value increased gradually due to the positive relationship with the gas storage filling variable. In the graph to the right, the latent water value entered the period at 51,5 €/ MWh and moved together with the electricity price in most of the period except late in September and the start of October, when the latent water value exceeded the NO5 electricity price for approximately two weeks. In that period, Naddvik refrained from producing. Naddvik's latent water value peaked in December at 209,3 €/ MWh and tended to be in the market more often as the electricity price rapidly increased.

5.2.16. Sy-Sima

Table 18: Model estimates for Sy-Sima.

Double Censored Regression Model

Variable	Est Coef	Std Err	z	P>|z|
LnCs	-0.1490	0.0520	-2.86	0.00
lnTtf	0.5851	0.0226	25.90	0.00
lnDfill_SySima	-0.6814	0.0304	-22.40	0.00
lnDfill_gas	-0.3562	0.0414	-8.60	0.00
lnTemp_bergen	0.0184	0.0095	1.94	0.05
lnTemp_voss	-0.0166	0.0086	-1.92	0.05
const	6.9931	0.3032	23.06	0.00

All coefficients are significant at a 5 % level. The estimated coefficients indicate that a 1 % increase in the reservoir filling of Sy-Sima is associated with a -0,68 % decrease in the latent water value, everything else held constant. A 1 % increase in the gas price is associated with an increase of 0,58 % in the latent water value. A 1 % increase in the degree of gas storage filling or the carbon spot price is associated with a decrease of -0,36 % and -0,15 % in the latent water value. Standard errors are small, which indicates precise estimates.

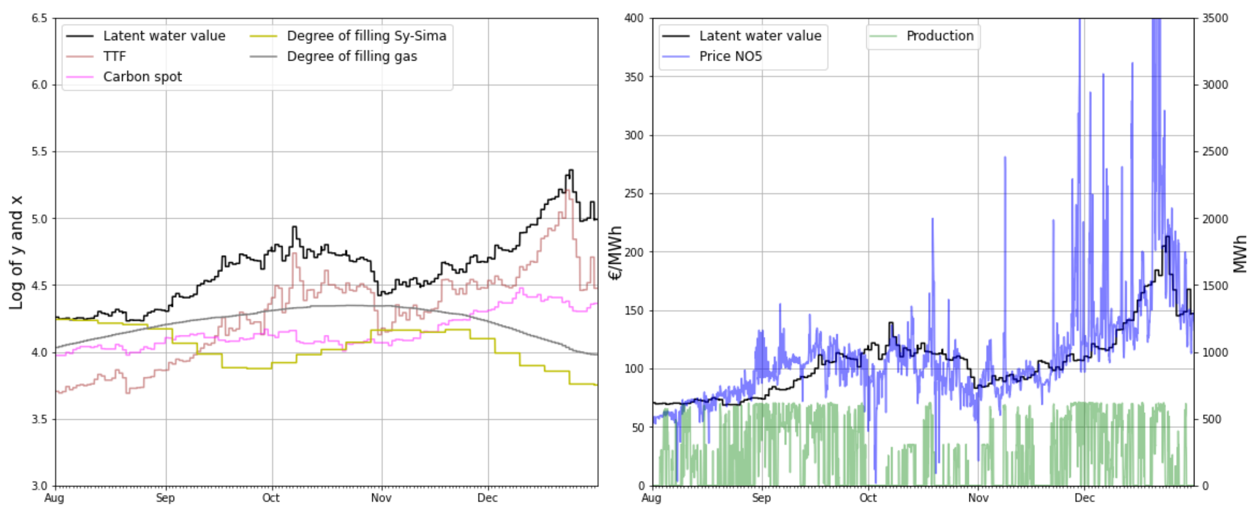

Figure 30: Latent water value of Sy-Sima, incl. market signals, NO5 price and production.

In the figure to the left, the latent water value had a generally increasing trend throughout the period. The latent water value increased with an increase in the gas price and decreasing reservoir filling at the start of the period, while the slope of the latent water value curve seemed to be steeper in the latter part of the period, as the reservoir filling and gas storage filling decreased, and the gas price increased. To the right, the latent water value of Sy-Sima entered the period at

70,5 €/ MWh and showed a tendency to be below the electricity price from mid-August to October, indicating production and frequent participation in the day-ahead market. Then, the latent water value moved more frequently in and out of the market until a sharp decrease in late October. Thereafter, the latent water value gradually increased, with a steep rise towards the peak in December with a value of 213 €/ MWh. Finally, the latent water value exited the period at 147 €/ MWh.

5.2.17. Tyin

Table 19: Model estimates for Tyin.

Double Censored Regression Model

Variable	Est Coef	Std Err	z	P>|z|
LnCs	10.0421	1.5141	6.63	0.00
lnTtf	-5.9843	1.0567	-5.66	0.00
lnDfill_Tyin	0.5659	0.8209	0.69	0.49
lnDfill_gas	6.0395	1.1862	5.09	0.00
lnTemp_bergen	1.1964	0.2187	5.47	0.00
lnTemp_voss	0.7469	0.1846	4.05	0.00
const	-43.1508	7.6705	-5.63	0.00

All variables are significant except the degree of reservoir filling variable. The model shows abnormally high estimated coefficients for the carbon spot, TTF and degree of gas storage filling, despite significant p-values. The high standard errors may indicate imprecise estimates.

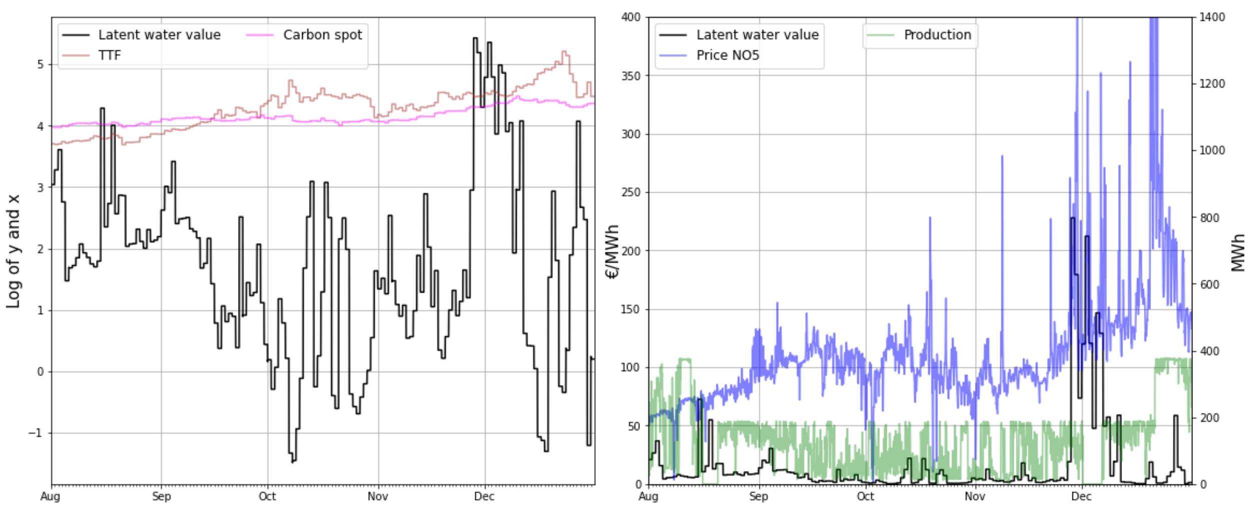

Figure 31: Latent water value of Tyin, incl. market signals, NO5 price and production.

The graphs show the very volatile and fluctuating latent water value of Tyin, which were at a completely different scale relative to the TTF, carbon spot and the area electricity price for NO5. Tyin produced close to continuously throughout the period, and the electricity price exceeded the latent water value except for approximately two weeks at the end of November and the start of December, which resulted in a goodness of fit result of 93,22 %. Tyin entered the period with a value of 20,9 €/ MWh and had a maximum price of 227,7 €/ MWh.

5.2.18. Double censored regression model - summary and discussion of RQ1 and RQ2

RQ1: *What were the water values of individual hydropower plants in the period and how did the water values develop in relation to the electricity price?*

Price area NO2

For the hydropower plants in NO2, we found a lot of variation in the latent water values in the period of interest. In the figure below, Tjodan stands out, as the plant entered and exited the period with latent water values within the same range as the other hydropower plants. However, in the middle and end of the period, Tjodan’s latent water values increased drastically, with a peak value in October of 832 €/ MWh. It may reflect that Tjodan had higher price expectations compared to the competitors. Nevertheless, noise in the production data seems like a more plausible cause. Inspection of the production data revealed that Tjodan produced small amounts of energy just above the threshold set in our model. An explanation could be that Tjodan produced to operate the Tjodanpollen pump station, which moves water between Tjodan’s reservoirs. Thus, some of the production captured in the model may be unrelated to bids to the day ahead market, resulting in unreliable latent water values. Moreover, the results from the I.I.D assumption imply that the estimates may be biased, which may be the reason that Tjodan stands out.

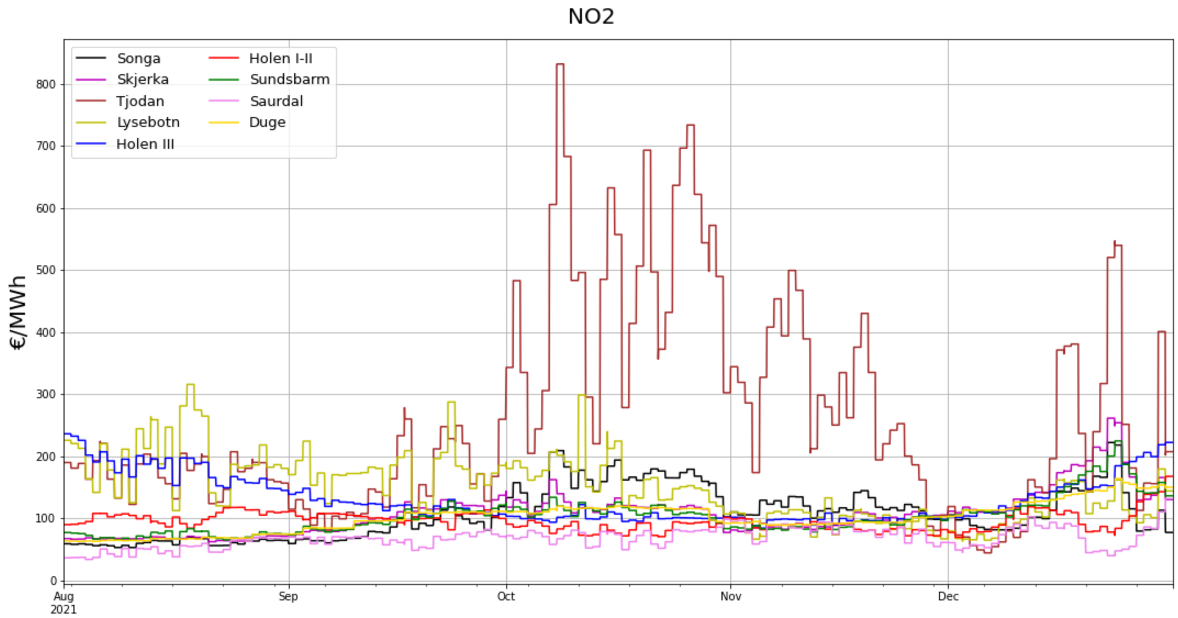

Figure 32: The latent water values of the hydropower plants in price area NO2, excl. Tysso II.

In the next graph, Tysso II and Tjodan have been excluded so that we get a more detailed presentation of the other hydropower plants' estimated results.

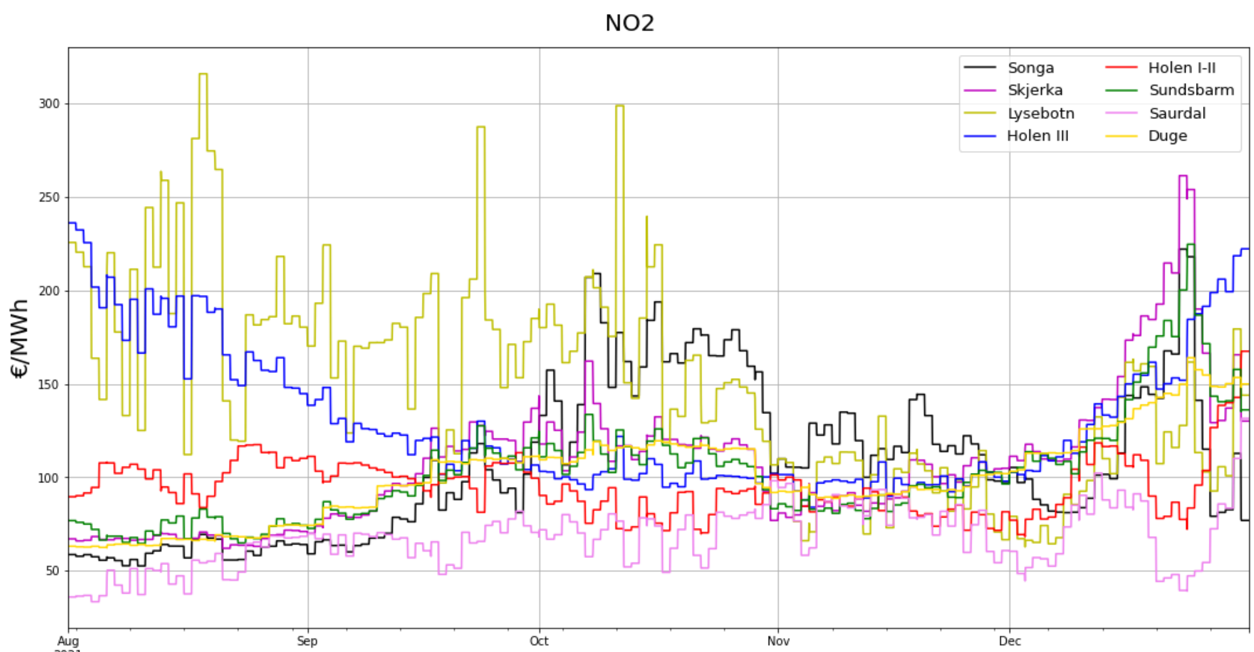

Figure 33: The latent water values of the power plants in price area NO2, excl. Tysso II and Tjodan.

The graph above shows that there was great variation both in terms of trends and valuation of the water in the reservoirs. Skjerka entered the period 1st of August with the lowest latent water value of 36 €/ MWh, while Holen III had the highest latent water value of 235,5 €/ MWh at the same point in time. At the turn of the year, Songa had the lowest latent water value at 77 €/ MWh, while Holen III had the highest at 222,1 €/ MWh.

Duge, Saurdal, Skjerka, Songa and Sundsbarm had a generally increasing trend in the latent water values throughout the period. On the 1st of August, their latent water values ranged from 36 €/ MWh to 76,9 €/ MWh, while on the 31st of December the latent water values ranged from 77 €/ MWh to 149,9 €/ MWh. The maximum latent water values occurred in December and ranged from 131,5 €/ MWh to 261,2 €/ MWh, which is significantly higher than in August. As seen in the graph above, the latent water values typically had a local peak in October, and a drop in November, before increasing towards the end of the period, with a final drop after the peak in December. The hydropower plants' latent water values followed different paths beneath and above the electricity price before eventually converging towards each other in November and moving together with the electricity price towards the peak in December. One reason for this could be that the producers had different expectations with respect to the electricity price earlier in the period and that the expectations became more uniform when approaching November. It could also imply that the hydropower producers adjusted their models and strategies in response to the changing market signals at some point in the period.

The increasing latent water value trends for Duge, Saurdal, Skjerka, Songa and Sundsbarm suggest that the hydropower producers bid a higher marginal cost to the day-ahead market in the late autumn and winter, compared to the summer and early autumn. One explanation could be that the producers, early in the period, did not expect a drastic increase in electricity prices, as the latent water values were relatively low. Additionally, it seems like the values were adjusted upwards gradually, as more information became available and expectations with respect to the electricity price changed. Another explanation could be that the latent water values increased due to an increase in marginal costs of thermal production, which resonates with the theory on the merit order curve. This is plausible, as we know that both gas prices and the prices on carbon spot increased in the period, while the gas storage filling was lower than expected.

Saurdal’s latent water value deviated with a drop when the other power plants had a peak in the latent water value in December. One possible explanation could be that Saurdal had different expectations with respect to the electricity prices relative to the other hydropower plants. If Saurdal believed the prices would fall, they may have adjusted the latent water values down as they expected lower future revenue on their water. In contrast, the other hydropower plants may have expected the opposite, and thus adjusted the latent water values upwards to maximize their revenue at a higher price. Another possibility could be that Saurdal interpreted other market signals differently from the competitors. Saurdal may have expected a high level of inflow as there was higher than normal precipitation in the period, which could signalize increased supply and lower electricity prices. On the other hand, December is not commonly a filling period, so one could argue that it is more likely that other market signals played a more significant role in Saurdals’ decreased latent water values.

Holen I-II, Holen III and Lysebotn II had a decreasing trend in the latent water value throughout the period except for in December, when the latent water values increased. For these three, the latent water values on the 1st of August ranged from 89,6 €/ MWh to 235,9 €/ MWh, while they ranged from 143,9 €/ MWh to 222,1 €/ MWh on the 31st of December. For Holen III and Lysebotn II, the latent water values were lower at the end of the period compared to the values in the beginning. In August, the latent water values of Holen III and Lysebotn II peaked at respectively 235,9 €/ MWh and 315,4 €/ MWh. For Holen I-II, the peak occurred at the turn of the year, with a lower latent water value of 167,4 €/ MWh. The difference in the trend and the latent water values for Holen I-II and Holen II was somewhat unexpected, as these powerplants are located in the same hall, and are operated by the same company. However, Holen I-II utilizes several different reservoirs, while Holen III only gets water from one perennial reservoir, which may imply that the operators have different long- and short-term strategies for these two plants.

The high latent water values of Lysebotn II and Holen III at the beginning of the period suggest that the producers were expecting a high return on the water in the future and that it would be more profitable to save the water for periods of higher prices and demand. One explanation for the high latent water values could be that they anticipated the electricity price increase, and accounted for it in their models such that the latent water values reflected the expectations. One could also argue that the producers valued the water highly due to the low inflow to the reservoirs at the start of the period. The decreasing trend until December suggests that the price expectations may have been adjusted down over time. However, it may also reflect the high levels of precipitation that occurred after mid-September, as hydropower producers tend to reduce the water value if the reservoir levels increase. This argument is supported by the fact that the power plants had little or no production before mid-September and produced regularly after this point in time.

Price area NO5

Below we see the development in the latent water values from the power plants in NO5. By excluding Tyin and Jostedal, we get a more readable graph with a more prominent trend among the power plants.

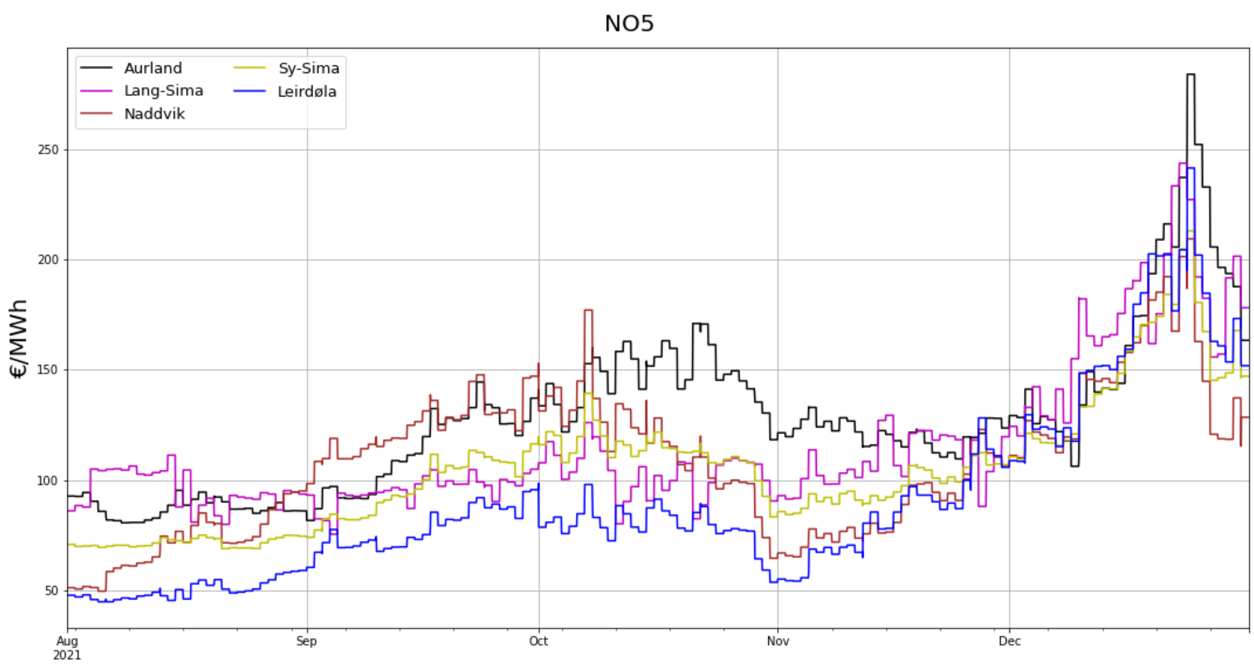

Figure 34: Predicted water values for the hydropower plants in NO5, excl. Tyin and Jostedal.

Leirdøla entered the period with the lowest latent water value of 47,7 €/ MWh while Aurland III had the highest latent water value of 92 €/ MWh. The graph shows that Lang-Sima had a slightly flatter trend from the start of the period until October, and that Leirdøla was below all the power plants in this period. Aurland III, Naddvik and Sy-Sima had a stronger increase until their local peak in October. Furthermore, we see that the latent water value of Aurland III was rather increasing and remained at a high level compared to the other power plants during October. Naddvik and Sy-Sima had the strongest decreasing trend in the latent water value at the same time, which corresponds to the fact that they had a higher degree of filling in the reservoir in that period, and thus could allow reducing the value of the water as they had more of it. Leirdøla had a fairly low latent water value compared to the others. It may indicate that Aurland III had an expectation of higher prices later in the period as they required 170 €/ MWh to start producing compared to Naddvik and Sy-Sima which reduced their price of the water. At the same time, Aurland III had the lowest degree of filling compared to the others in NO5, thus it could be more likely for them to price their water higher to maximize its value.

Moreover, every power plant had a drop of varying extent at the very end of October in accordance with the sharp reduction in the electricity price at the same time. In November, the power plants converged towards each other and followed the trend in line with the increasing electricity price towards the peak in December where every power plant reached its peak price. Aurland III had the highest peak with a latent water value of 284 €/ MWh, followed by Lang-Sima at 243,3 €/ MWh, Leirdøla at 241,5 €/ MWh, Sy-Sima at 213 €/ MWh and Naddvik with the lowest peak at 209,3 €/ MWh. We clearly see that the marginal costs of each power plant bid for Nord Pool increased from early autumn to the end of December. The latent water value then dropped for all power plants at the end of the analysis period, where Naddvik had the largest decrease. The reduction corresponds to the decrease in the electricity price.

Abnormal estimates

The high abnormal estimates and a poor fit of the predicted model for Tyin, Jostedal and Tysso II, make it difficult to interpret the latent water value and the results show that they are on a completely different scale relative to the other power plants. The results from the testing of the I.I.D assumption indicate that the estimation of these power plants is biased, which may be a part of the explanation for the abnormal estimates.

Furthermore, the estimation of the latent water value is conditional upon information that becomes visible only when the hydropower producer is in and out of the market. During these production intervals, the model predicts the position of the latent water value in relation to the independent variables. However, when Tyin, Jostedal and Tysso II consistently participate in the market over a long period, the model's predictive ability is prevented, given their permanent production irrespective of the development of the independent variables, which results in abnormal and questionable predictions. Furthermore, part of the explanation for the abnormal estimates for Jostedal is that the river associated with the Jostedal power plant, Jostedøla, has inflicted significant damage due to flooding in the past. Furthermore, the degree of filling was close to 80 % in the second week of September. The high reservoir level and the history of flooding may have contributed as an incentive to lower the water values, at least for a period, to produce and mitigate the risk of flooding. However, as the reservoir level decreased after September, the flood risk from overflowing reservoirs may have had limited meaning for the water values later in the period.

RQ2: *How did the gas prices, CO2 prices, reservoir filling and the European gas storage filling influence the water values.*

Price area NO2

The table below shows the estimated coefficients with a significant p-value below the 5 % level for the respective power plants. The estimates show that there is great variation in how the latent water value was influenced by the market signals.

Table 20: Estimated coefficients from the double censored regression model in NO2.

	Duge	Holen I-II	Holen III	Lysebotn II	Saurdal	Skjerka	Songa	Sundsbarm	Tjodan	Tysso II
Carbon Spot	-	-	-0.741	-1.076	0.449	-0.336	-2.037	-0.453	-7.501	-106.9
TTF	0.155	-0.552	-0.094	0.616	-0.770	1.029	1.528	0.638	2.667	32.85
Degree filling	-1.617	-2.796	-0.637	-0.883	-2.620	-0.258	0.353	-0.860	0.372	-
Gas storage	-0.421	-0.139	-2.208	-1.412	0.977	-0.647	0.412	-0.572	-2.247	-

As a higher carbon spot price contributes to higher marginal costs for thermal producers, it is intuitive to assume that hydropower producers have a positive relationship with carbon spot. Based on the estimates, it appears that only the latent water value for Saurdal is positively influenced by the carbon spot. Disregarding the abnormally low estimates for Tjodan and Tysso II, the latent water values for Songa decrease the most when the carbon spot increases.

The same applies to TTF, where a higher gas price causes the gas producers to be higher on the merit order curve, which can lead to a higher electricity price if they are the marginal producer. It will thus be intuitive to assume that the hydropower producers follow the development of the gas price. The estimates show that the latent water values for Holen I-II, Holen III and Saurdal are negatively influenced by an increase in the gas price, while the remaining power plants increase their latent water values when TTF increases.

For the degree of filling in the reservoirs, the estimates reveal that only Tjodan and Songa increase their latent water values when the degree of filling increases. The other power plants value their water more the less they have of it, which is expected. The estimates for Tjodan and Songa thus appear to be the opposite of what the theory implies which makes us question the estimates in the model, as they value their primary source less the smaller amount they have of it, which will lead to them depleting the reservoir the less water there is. The estimates for Tjodan may be biased due to a possible violation of the I.I.D assumption, thus the coefficients may be unreliable.

Furthermore, the estimates show that Saurdal and Songa are positively influenced by the degree of filling in the gas storage, while the rest in NO2 have a negative relationship with gas storage. This indicates that when the filling rate in gas storage rises, the latent water values in Saurdal and Songa will increase. Gas storage in Europe was at a 10-year low during the estimation period, implying that there will be higher demand when the heating season starts, which in turn will affect demand for electricity and gas. Lower gas storage can thus be a sign for power producers that higher electricity prices will occur when heating season starts, and that saving water can lead to higher profits later in the period. Hence, a negative relationship with gas storage will be intuitive. But it may appear that there are different views on gas storage as a fundamental factor for Saurdal and Songa compared to the other power plants.

Price area NO5

The estimates for NO5 reveal that the power plants emphasize the fundamental factors differently, but a rather more expected result with respect to theory than the power plants in NO2.

Table 21: Estimated coefficients from the double censored regression model in NO5.

	Aurland III	Jostedal	Lang-Sima	Leirdøla	Naddvik	Sy-Sima	Tyin
Carbon Spot	-1.287	-37.35	-	0.385	0.645	-0.149	10.042
TTF	0.537	24.30	0.541	0.540	0.752	0.585	-5.984
Degree filling	-1.321	-	-	-2.061	-1.223	-0.681	-
Gas storage	0.159	-13.58	-1.357	-0.074	1.312	-0.356	6.039

Leirdøla and Naddvik are positively influenced by the carbon spot price if we ignore the erroneous estimates for Tyin. Sy-Sima and Aurland III reduce their latent water value when carbon spot increases, whereas Aurland III has a fairly high and unexpectedly large coefficient if we ignore the estimates for Jostedal.

Moreover, the models estimate that all the power plants increase their latent water values when the TTF increases, with the exception of the large deviation in Tyin. The power plants are influenced by the changes in TTF at a relatively similar level, except for the high estimates for Jostedal. This indicates that TTF is a consistently important factor that they incorporate into their models when they calculate the latent water values, which is in line with expectation and theory. Naddvik has the highest coefficient of TTF, otherwise Sy-Sima, Leirdøla and Aurland III are at about the same level. This may indicate that TTF has a slightly higher influence on the latent water value in Naddvik than the rest.

Furthermore, the estimates show that all the power plants have a negative relationship with the coefficient in the degree of filling, which is in line with the theory. This indicates that the producers increase the latent water value, the less they have of it. Leirdøla increases its latent water values the most, followed by Aurland III and Naddvik.

Additionally, we see that the power plants have somewhat different relationships with gas storage, which was also the case for the power plants in NO2. Aurland III and Naddvik have an unexpected reduction of the latent water values when gas storage decreases, whereas all the other power plants increase their latent water values when the degree of filling in gas storage decreases.

Only Leirdøla has an intuitive relationship with the market signals that one might assume and what the theory implies, with a positive relationship with carbon spot and TTF, and a negative relationship with degree of filling and gas storage.

5.3. Structural breaks

5.3.1. Holen I-II

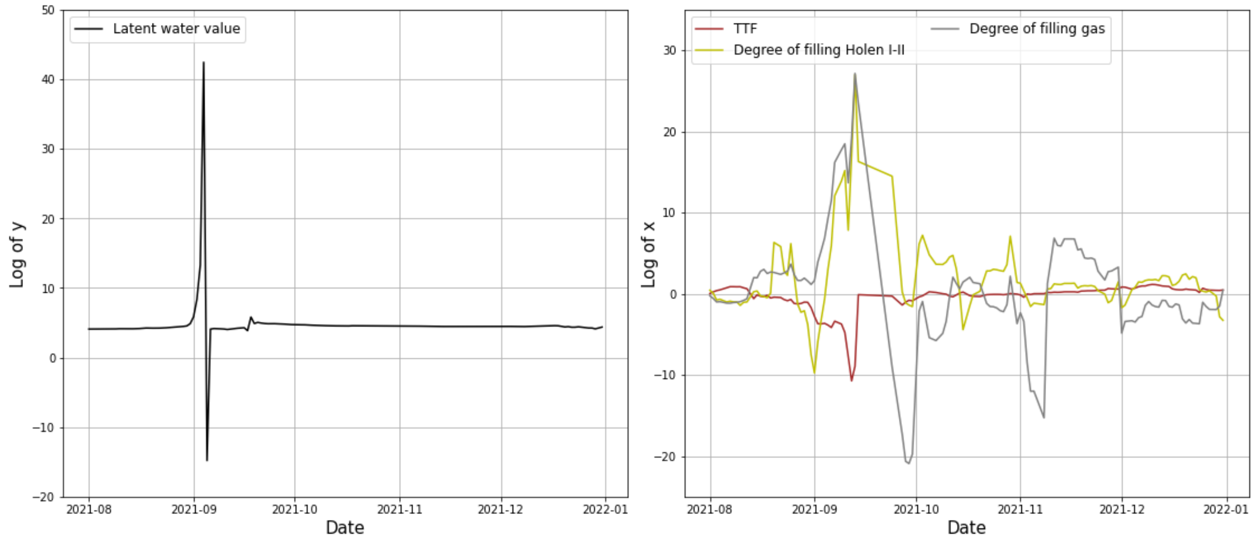

Figure 35: Structural breaks in the latent water value of Holen I-II and in the market signals

The estimation shows that the latent water value for Holen I-II had a structural break at the beginning of September. At the same time, the degree of filling for Holen I-II, TTF and degree of gas storage filling had a structural break.

5.3.2. Lysebotn II

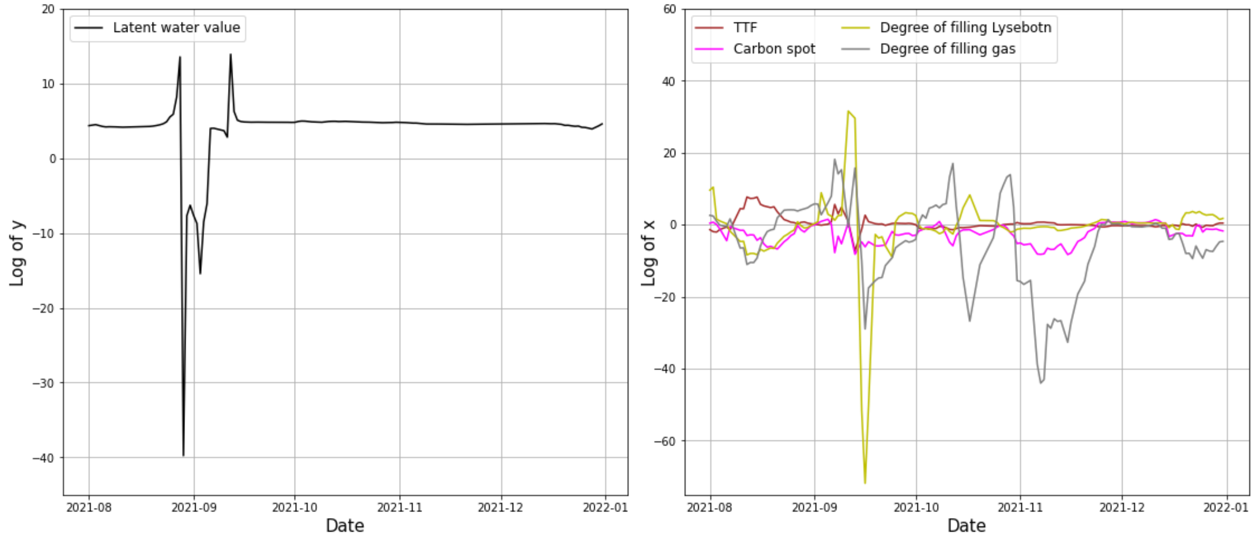

Figure 36: Structural breaks in the latent water value of Lysebotn II and in the market signals

To the left, we see that there was a structural break in latent water value, occurring at the end of August and the start of September. The graph to the right indicates that there was a corresponding break in the reservoir filling and gas storage filling in September.

5.3.3. Saurdal

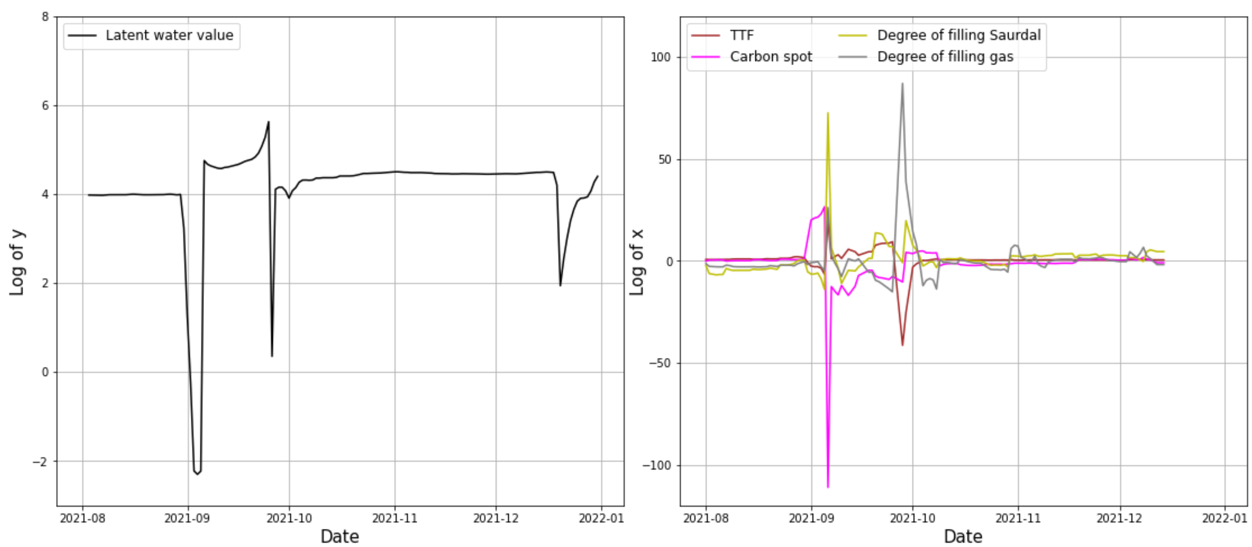

Figure 37: Structural breaks in the latent water value of Saurdal and in the market signals.

The figure to the left indicates two structural breaks in the latent water values in September, and a break in mid-December. There was a break in the carbon spot price, TTF gas price, the gas storage filling, and the degree of filling of Saurdal at the same time as the latent water value at the start of September. Furthermore, the second break in the latent water value corresponds to a structural break in both the gas price and the degree of gas storage filling. There was no significant break in the market signals during the break in the latent water value in December.

5.3.4. Songa

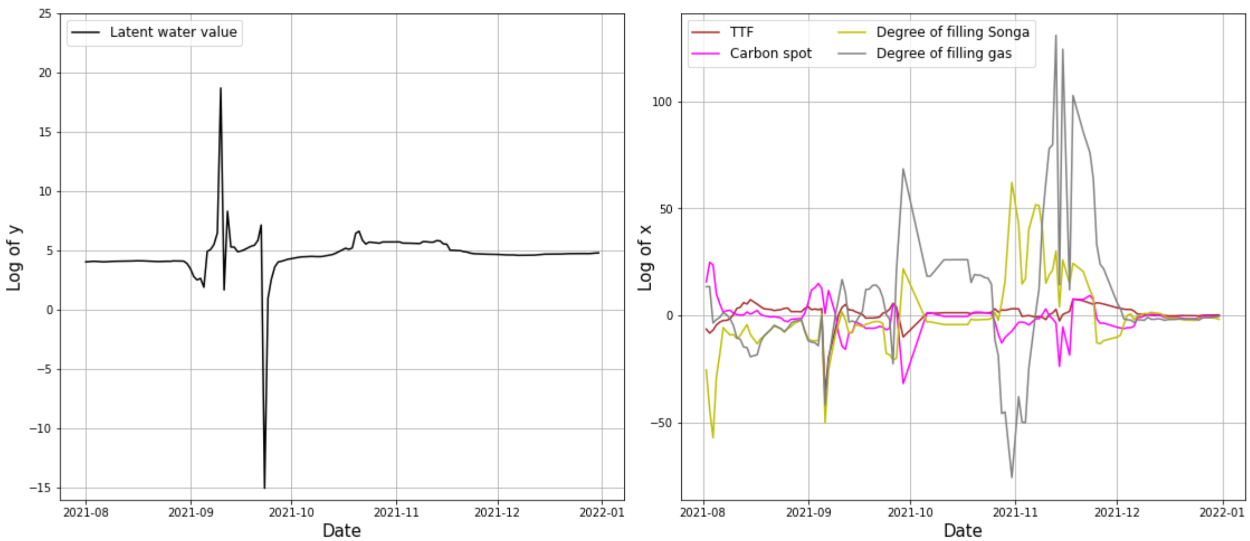

Figure 38: Structural breaks in the latent water value of Songa and in the market signals

The figure to the left suggests two structural breaks in the latent water value of Songa in September. The first structural break occurred right after a structural break in the TTF gas price, the degree of filling of Songa and the degree of gas storage filling. Furthermore, the second break happened at the same time as a structural break in the degree of gas storage filling and the carbon spot.

5.3.5. Tjodan

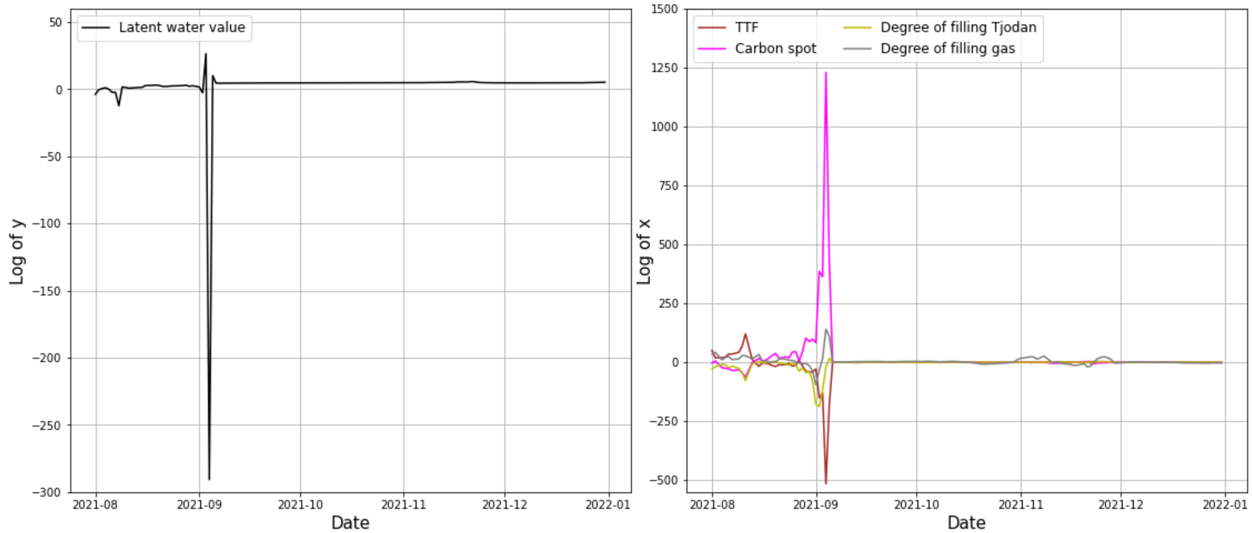

Figure 39: Structural breaks in the latent water value of Tjodan and in the market signals

The latent water value for Tjodan has a structural break at the start of September. At the same time, all the market signals reveal a structural break, where carbon spot and TTF have the largest break.

5.3.6. Jostedal

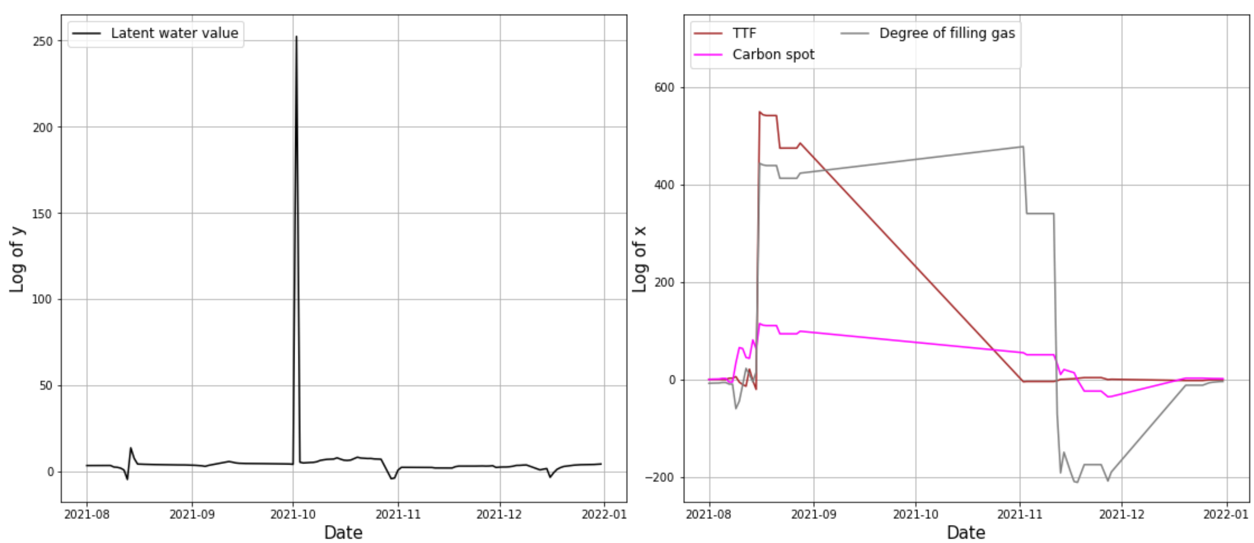

Figure 40: Structural breaks in the latent water value of Jostedal and in the market signals

The first graph suggests that there was a structural break in the latent water value of Jostedal at the beginning of October. There is no meaningful structural break in the market signals at the point in time of the structural break in the latent water values.

5.3.7. Leirdøla

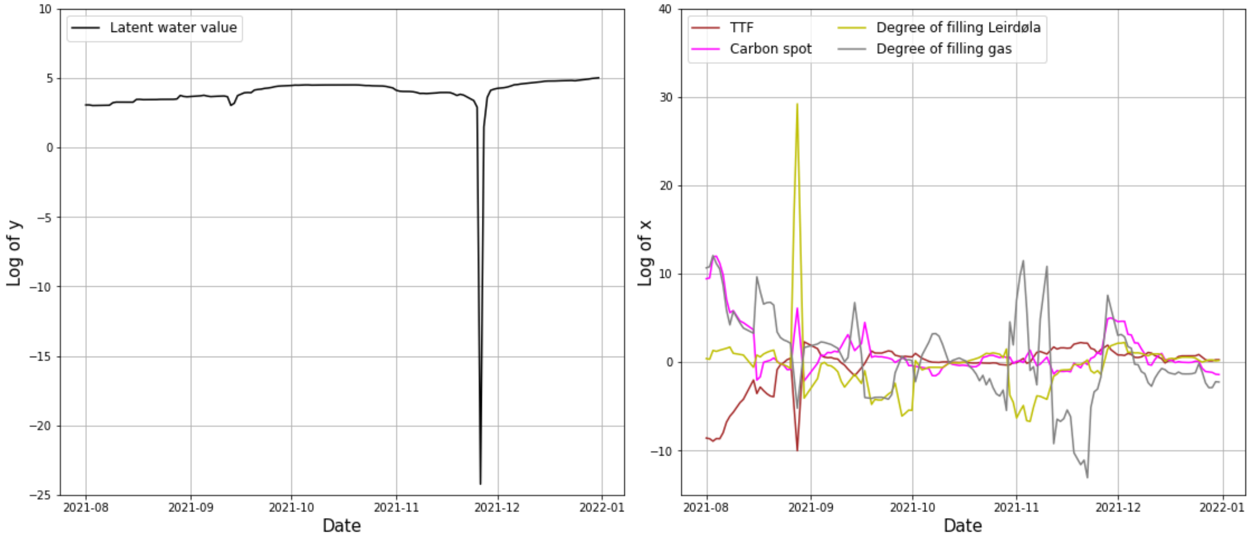

Figure 41: Structural breaks in the latent water value of Leirdøla and in the market signals

The model estimates that the latent water value for Leirdøla has a structural break at the end of November. The graph on the right shows that there are no clear breaks that can explain the break in the latent water value, but the degree of filling in gas storage has an upward change in the same period as the break in the latent water value.

5.3.8. Naddvik

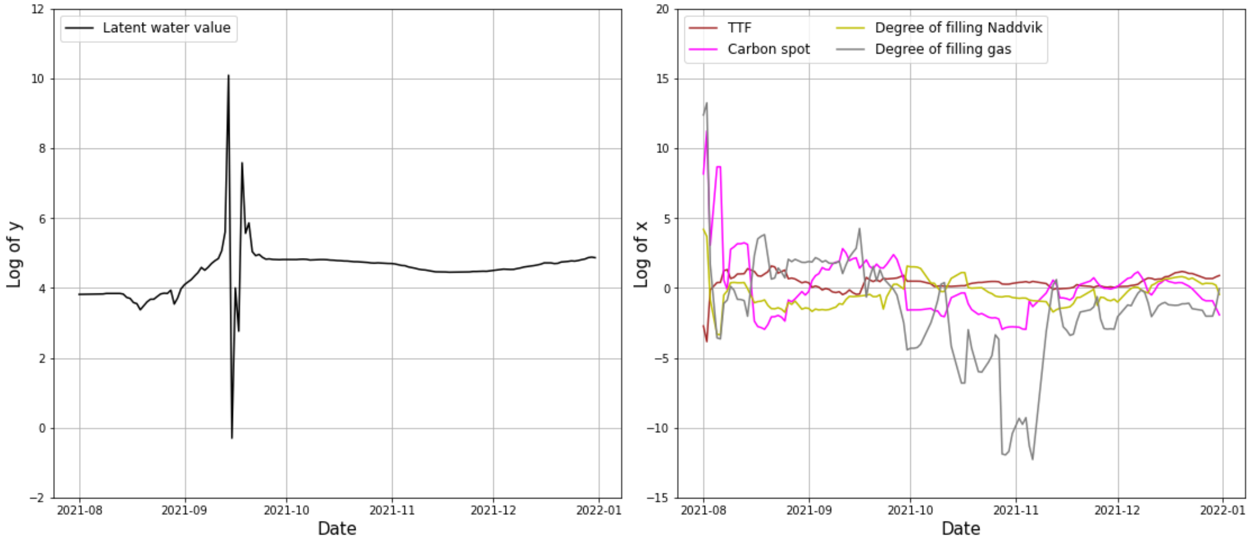

Figure 42: Structural breaks in the latent water value of Naddvik and in the market signals

The graph to the left shows that the latent water value for Naddvik has a break in mid-September. Furthermore, we can see in the graph to the right that none of the market signals has any significant break at the same time which gives no clear indications that a change in the included market signals has a connection with the structural break in Naddvik.

5.3.9. Tyin

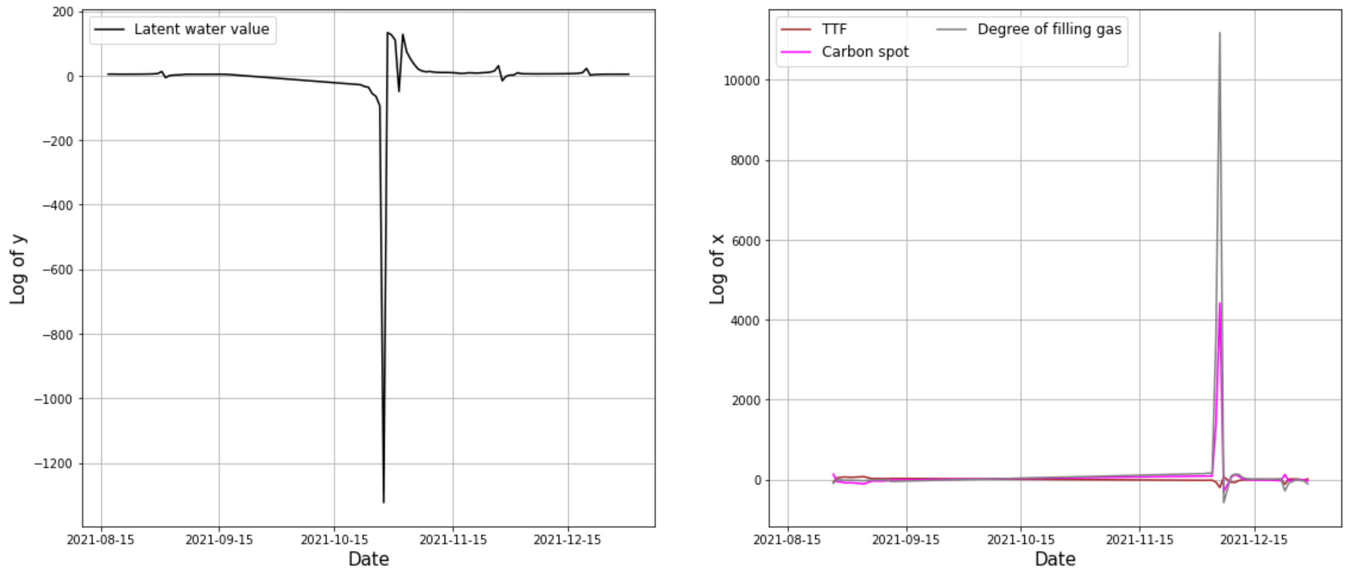

Figure 43: Structural breaks in the latent water value of Tyin and in the market signals

The significant drop in the estimated latent water values of Tyin indicates a structural break in late October. There are no structural breaks in the market signals occurring at the same time, hence we are not able to infer a connection with the market signals.

5.3.10. Structural breaks – summary and discussion of RQ3

RQ3: *When did the different hydropower producers respond to the market signals and which signals did they respond to?*

Structural breaks in the latent water values were identified for nine of the 17 hydropower plants in the study. Of these, six hydropower plants had structural breaks in one or several of the market signals, corresponding to a structural break in the latent water values. The remaining four hydropower plants showed a structural break in the latent water values which did not correspond to a structural break in the market signals.

Structural breaks in both the water values and the market signals

For the hydropower plants with structural breaks in both the latent water values and the market signals at the same point in time, the results indicate that Holen I-II, Saurdal, and Tjodan changed their expectations and prognosis models with respect to the TTF gas price and revised their fundamental models during the transition from August to September. Meanwhile, Songa responded approximately one week later. Furthermore, Saurdal had a second structural break in the latent water value that indicated a response with respect to the gas price at the end of September.

With regard to the carbon spot price, the results imply that Tjodan had a response to this market signal during the turn of the month from August to September, while Songa followed with a response to the carbon spot late in September.

For the degree of reservoir filling, the results imply that Holen I-II, Lysebotn II, Saurdal and Tjodan changed the expectations with respect to the market signal in late August-early September. Meanwhile, Songa responded approximately a week into September. One explanation for the responses could be that low inflow to the reservoirs prior to mid-September may have served as an incentive to adjust the expectations with respect to the reservoir filling, to save water and prevent further depletion of the reservoirs. This argument may be supported by the fact that the reservoir filling of these five plants in 2021 was lower than the average reservoir filling in in the price area in the previous four years. Another explanation could be that the hydropower producers had received new weather forecasts with an indication of the higher-than-normal level of precipitation in the area, which occurred from mid-September. This may in turn have served as an incentive to revise the model to account for the change in expectations with respect to the reservoirs filling. However, it is not known if the responses were specific for the period, or something that the hydropower producers do every year at the beginning of September.

The results suggest that Holen I-II, Lysebotn II, Saurdal and Tjodan had a change in expectations with respect to the European gas storage filling during the transition from August to September. Songa had a similar response approximately one week later, while both Saurdal and Songa responded for the second time with respect to the gas storage filling late in September. In addition, there was a vague indication that Leirdøla had a response to the gas storage filling in November.

To sum up, from the evidence, we found that Holen I-II, Lysebotn II, Saurdal, Songa and Tjodan revised their fundamental models once or twice in September, as a response to the market signals. However, the breaks in Tjodan may be due to a possible violation of the I.I.D assumption and consequently be reflected in false breaks. Furthermore, 100 % of the responses appear to be related to a change in expectations with respect to the European gas storage filling. 71 % of the responses seemed to be related to a change in expectations with respect to the degree of reservoir filling and the same was found for the gas prices. 43 % of the responses were associated with a change in expectations with respect to carbon spot prices. In addition, Leirdøla had a vague indication of a response in November associated with the European gas storage filling. Based on the analysis, it appears like several of the hydropower producers adjusted their models during the autumn of 2021. However, it is uncertain whether this was a one-time event or a recurring adjustment that the hydropower producers undertake every year. Furthermore, there are few results and a lot of uncertainty associated with these results, thus, the findings should be viewed with caution.

Structural breaks in the water values

Four hydropower plants had a structural break in the latent water values which was not accompanied by a corresponding response in the market signals. The responses were scattered through the period of interest, with Naddvik having a response in September, Jostedal and Tyin responded in October, and Saurdal in December. These responses may be related to a change in expectations with respect to some factors that we were not able to identify in our analysis. For instance, Tyin supplies the aluminium industry, thus the structural break in the latent water value could possibly be explained by factors related to that side of their business. It is also plausible that the structural breaks in the latent water values and market signals were influenced by the hydropower producer's production patterns or technical issues with the models. Jostedal and Tyin had small variations in production, which may be the reason behind the big leaps in the market signal curves in the figures for these two power plants. Moreover, Tyin produced almost constantly, and carbon spot and gas storage filling signals both had structural breaks in December, coinciding with a five-day period of non-generation. Regarding Saurdal, the model did not generate estimates for the market signals for the two last weeks of December, such that we were unable to assess the last structural break in the water values against the market signals. Lastly, the structural breaks in the latent water values and the market signals may also be the result of random fluctuations or noise in the data.

Absence of structural breaks

Eight of the hydropower plants did not have a structural break. Hence, we were unable to determine when they responded to the market signals. It applies to Holen III, Sundsbarm, Tysso II, Aurland III, Sy-Sima, Skjerka, Duge and Lang-Sima.

6. Concluding remarks and recommendations

6.1. Summary of findings

This analysis presented the development of the water values of 17 hydropower plants in southern Norway from August to December 2021, along with the effects on the water values from developments in the gas price, carbon spot price, European gas storage levels and the hydropower plant specific reservoir levels. In addition, the timing of the hydropower producers' responses to the market signals were presented.

First, we analyzed the development of the water values for each of the hydropower plants separately, and within each of the NO2 and NO5 price areas. Time series data from the 1st of August to the 31st of December and the double censored regression model with MLE were used to derive the latent water values for each plant. We found that the water values of 10 of the 17 plants in price areas NO2 and NO5 had a generally increasing trend throughout the period. The hydropower plants entered the period at different water value levels, and converge towards each other in October-November, before moving together with the electricity price towards a peak in December. There were three plants in price area NO2 that had a decreasing trend towards November, moved together with the other plants in December, and had a drop in the water values as they approach the peak in December. There was more variation in the water values in price area NO2 compared to NO5. Three power plants had minimal variation in their production patterns, resulting in abnormal latent water values. Consequently, their results were not considered alongside the 14 power plants with more well-behaved results.

Secondly, we analyzed how the water values of the individual hydropower plants changed as a response to changes in the TTF-gas price, carbon spot price, the European gas storage filling and individual hydropower producers' reservoir filling. The double censored regression model was used. We evaluated the significance and direction of the estimated coefficients and performed a graphical interpretation of the water values against the market signals. We found that the response to the market signals varied significantly among the power plants, and in some cases, there were market signals that were not significant at a 5 % level. For the 14 hydropower plants with well-behaved results and where the individual market signal was significant, we found that 78,6 % increased the water values as a reaction to a rise in the gas price. If the European gas storage levels increased, 71,4 % of the producers tended to lower the water values. Furthermore, when the carbon spot price increased, 27 % of the producers tended to adjust the water values upwards. If there were inflow to the reservoirs such that the reservoir filling increased, 84,6 % of the producers tended to lower the water values. The most surprising result was that the model estimated a negative relationship between the carbon spot price and the water values for a significant share of the hydropower producers, as increasing marginal costs in thermal production typically lead to increasing water values, not the opposite. Another unexpected result was that the reservoir filling was not significant for Lang-Sima, as reservoir filling is a fundamental factor that hydropower producers consider when they calculate their water values.

Lastly, we determined and analyzed the timing of the hydropower producers' response to the market signals. We applied the rolling window method with a four to six weeks window to our censored regression model, to identify structural breaks in the latent water values and the market signals. We found structural breaks in the latent water values for 9 of the 17 power plants in our study. 67 % of the structural breaks had corresponding structural breaks in the market signals. Holen I-II, Saurdal, Songa, Lysebotn II and Tjodan all had breaks in the water values in late August and September, of which 100 % and 71 % of the breaks indicated a change in the producer's expectations and prognosis models for the European gas storage filling and the reservoir filling respectively. Moreover, 71 % and 43 % of the breaks could indicate a similar change in the expectations and prognosis models for the gas price and the carbon spot price. These findings indicate that these five hydropower producers reassessed their models for calculating the water values in September as a response to the market signals. However, due to few results and a lot of uncertainty, the findings should be viewed with caution.

These findings are relevant for policymakers as they will gain insight into how external price shocks affect hydropower production in Norway. With a closely integrated market with Europe, changes in external market signals will consequently affect how Norwegian hydropower producers price their water, where the gas price tends to be the signal that hydropower producers are most affected by. Furthermore, hydropower producers will benefit from seeing how they priced their water in relation to competitors and how their water values developed during the last half of 2021 compared to other producers.

6.2. Limitations of the study

There is a lot of uncertainty related to the structural break results in our analysis, and it is possible that we could have gained better results by using a different method. However, assessing structural breaks can be very time-consuming, and as we had limited time to complete this paper, other methods were not covered.

In the analysis, we disregard the fact that the hydropower producers may also participate in other markets than the day-ahead market. If that is the case, participation in the other markets could possibly be a source of error in our analysis, as we cannot identify production to the different markets in our data. Furthermore, the producers may be downregulated in the automatic Frequency Restoration Reserve market (aFFR), which means that they could be paid to withhold production. This could also affect our results, as we are not able to identify the reason behind non-production in the data.

Some of the independent variables have a slightly high correlation, which may be a limitation in the interpretation of the coefficients. Carbon spot and degree of filling in Aurland and Jostedal have a correlation of -0,81, and the degree of filling in Saurdal has a correlation of -0,83 with carbon spot. Furthermore, TTF and degree of filling in Saurdal have a correlation of -0,91, and the degree of filling in Leirdøla has a correlation with the degree of filling in gas storage of 0.8. Even if they are not exactly linear, they can still have an influence on the coefficients.

6.3. Recommendations and suggestions for further research

Further research could be done to include other market signals that hydropower producers evaluate when they derive their water values, such as coal prices, wind in Europe and long-term electricity price prognosis. Such research is valuable as it provides a more comprehensive picture of the factors that influence the water values. It is a relevant topic as the energy markets are transitioning to adhere to international climate goals and also in terms of changes in the European energy sector due to the restricted supply of gas from Russia. It could help both Norwegian hydropower producers and the society to identify the most efficient ways to allocate the water in the reservoirs, at a time when there is a great deal of uncertainty about the future energy situation.

Studies could be done, where our model is used together with data covering a longer period. Then it would be possible to assess if the result from our analysis is unique for the last five months of 2021, or if the development of the water values and relationships between the water values and the market signals were normal.

Further research could be done on the timing of the hydropower producers' responses to the market signals in the autumn of 2021. It could enable the comparison of different hydropower plants and hydropower operators' responses to the market signals and see if any patterns could be identified. We would recommend trying a different method than the rolling window and the Log-likelihood chi-square test to identify structural breaks if the dataset from this analysis were to be used, as these methods gave sparse results with a great deal of uncertainty.

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Appendices

Appendix 1. Percentage change in the average electricity price

Calculation of the percentage change (%Δ) in the average electricity price ($\boldsymbol{P_{Dec2x}}$) from the last week of December 2020 to the last week of December 2021 in price area NO2 and NO4. We used the day-ahead prices in $€/MWh$ from Nord Pool and calculated the weekly average price in Python.

$$\frac{P_{Dec21} - P_{Dec20}}{P_{Dec20}} \times 100 = \%\Delta$$

NO2: $$\frac{254{,}7€/MWh - 16{,}1€/MWh}{16{,}1€/MWh} \times 100 \approx 1\,482\ \%$$

NO4: $$\frac{47.8€/MWh - 12.3€/MWh}{12.3€/MWh} \times 100 \approx 289\ \%$$

Appendix 2. Power plant delimitation - overview.

Power plant delimitation		
Price area	Power plant >100 MW	Upstream power plants >10 MW and other notes.
NO1	Rendalen 2	Run-of-river Savalen and Tolga.
	Nedre Vin	Øvre Vinstra
NO2	Blafalli Vik	Other Blåfalli power plants
	Brokke	Holen I-II and Holen III
	Duge	-
	Holen I-II	-
	Holen III	-
	Kvilldal	Saurdal
	Lysebotn II	Breieva (far out relative to large reservoirs)
	Oksla	Tysso II
	Saurdal	-
	Skjerka	-
	Solhom	Kvinen, Sokrepp etc.
	Songa	-
	Sundsbarm	-
	Sønna	Stolivatn, Dalvatn
	Tjodan	-
	Tokke	Vinje
	Tonstad	Solhom
	Tysso II	Lack of variation in production in the period
	Vemork	Frøystil
	Vinje	Songa
NO5	Aurland I	Aurland III
	Aurland III	-
	Bjølvo	Installed capacity of 98 MW in 2021. No generation data in the period
	Borgund	Øljussjøen
	Dale	Fosse
	Evanger	Oksbotn
	Jostedal	Lack of variation in production in the period
	Lang-Sima	-
	Leirdøla	-
	Mauranger	Jukla
	Myster	Lack reservoir filling data
	Naddvik	-
	Sy-Sima	-
	Tyin	Lack of variation in production in the period.
	Usta	Ørteren, Usekveikja
NO3+NO4		Out of scope

Appendix 3. Powerplant characteristics – overview

ower plant characteristics												
ID	Price area	Power plant	Type	Put into operation (year)	Location (Municipality , county)	Waterway	Individual reservoir (Capacity in GWh) Total power plant reservoir capacity (GWh)	Main owner (Other owners (Share in %))	Operator	Number of generators and turbine type	Installed generation capacity (MW)	Average annual production (ref. 1991-2020) (GWh)
1	2	Duge	PS	1979	Sandnes, Rogaland	Sira-vassdraget	Svartevatn (776,1) Total: 776,1	Sira Kvina Kraftselskap (Agder Energi Vannkraft (12) Lyse Produksjon (41,1) Statkraft Energi (32,1))	Sira Kvina Kraftselskap	2 Francis turbines	200	206,1
2	2	Holen I-II	SR	1981	Bykle, Agder	Otra-vassdraget	Vatnedalsvatn (673,9), Skyvatn (29,7), Ormsvatn (17,9), Store Førresvatn (12), Breivatn (9,7), Hartevatn (6,2) Total: 749,6	Otra Kraft DA (Agder Energi Vannkraft (68,6), Skagerak Kraft (31,4))	Agder Energi Vannkraft	2 Francis	174	682,2
3	2	Holen III	SR	1986	Bykle, Agder	Otra-vassdraget	Urarvatn (384,6) Total: 384,6	Otra Kraft DA (Agder Energi Vannkraft (68,6), Skagerak Kraft (31,4))	Agder Energi Vannkraft	1 Francis	160	341,8
4	2	Lysebotn II	SR	1953/ 2018	Sandnes, Rogaland	Åredals- and Lyse-vassdraget	Lyngsvatn (859,3), Nilsebuvatn (69,4), Strandevatn-Storetjøm (38,2), Breiava (31,7) Total: 998,7	Lyse Produksjon (100)	Lyse Produksjon	2 Francis	370	1475,7
5	2	Saurdal	SR PS	1985	Suldal, Rogaland	Otra-, Førreøna- and Ulladalsøna-vassdraget	Storvatn (1531,8), Oddatjøm (883,4), Førrevatn (770,5) Total: 3185,7	Statkraft Energi (72) (Lyse Produksjon (18), Otra Kraft DA (7,3), Sunnhordaland Kraftlag (2,5), Agder Energi Vannkraft (0,2))	Statkraft Energi	2 Francis 2 Deriaz turbines (reversible pump)	640	1063,7
6	2	Skjerka	SR	1997	Åseral, Agder	Mandals-vassdraget	Nåvatn (111,5), Skjerkevatn (62,7), Langevatn (43,6), Kvernevatn (35,2), Storevatn (10), Stegilvatn (10) Total: 273,1	Agder Energi Vannkraft (100)	Agder Energi V.	2 Francis	104	764,5

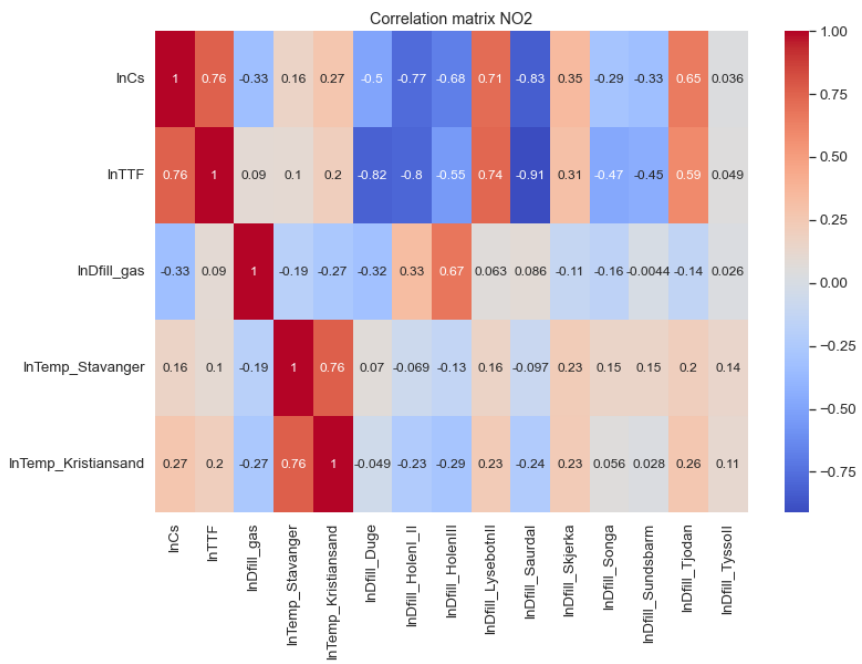
7	2	Songa	SR	1964	Vinje, Vestfold og Telemark	Skiens-vassdraget	Bitdalsvatn (70,4) Total: 70,4	Statkraft Energi (100)	Statkraft Energi	1 Francis	136	619,5
8	2	Sundsbarm	SR	1970	Seljord, Vestfold og Telemark	Skiens-vassdraget	Sundsbarmvatn (242,5), Sandsetvatn (11,4), Ljosdalsvatn (7,5) Total: 261,4	Skagerak Kraft (91,5) (Vest-Telemark Kraftlag (8,5))	Skagerak Kraft	1 Francis	110	396,4
9	2	Tjodan	SR	1984	Sandnes, Rogaland	Tjodan-vassdraget	Store Tjodanvatn (114,6), Andersvatn (44,4), Lille Tjodanvatn (34,8), Låtervikvatn (4,1) Total: 197,9	Lyse Produksjon (100)	Lyse Produksjon	1 Pelton	113	364,2
10	2	Tysso II	SR	1967	Ullensvang, Vestland	Tysso-vassdraget	Håvardsvatn (218,7) Langevatn (317,9) Breiavatn (148,9) Øvre Tyssevann (87,5) Nibbehølen (41,7) Total: 814,2	Statkraft (100)	Aktie-selskabet Tysse-faldene	2 Peleton	220	1117,6
11	5	Aurland III	PS	1979	Aurland, Vestland	Aurlands-vassdraget	Nyhellervatn (420,6) Total: 420,9	Hafslund Eco (93) (Statkraft Energi (7))	Hafslund Eco	2 reversible Francis pump turbines	270	94,5
12	5	Jostedal	SR	1989	Luster, Vestland	Jostedøla	Styggevatnet (987,2), Kupvatnet (402,8) Total: 1390	Statkraft Energi (100)	Statkraft Energi	1 Pelton	290	932,1
13	5	Lang-Sima	SR	1980	Eidfjord, Vestland	Austadøla	Langvatn (429,8), Rundavatn (61), Skruelsvatn (16,1) Total: 507	Statkraft Energi (65) (Eviny (26,25), Sunnhordaland Kraftlag (8,75))	Statkraft Energi	2 Pelton	500	1252,5
14	5	Leirdøla	SR	1978	Luster, Vestland	Jostedøla	Tunsbergdalsvatn (181,9) Total: 181,9	Statkraft Energi (100)	Statkraft Energi	1 Francis	115	498,4
15	5	Naddvik	SR	1987	Årdal, Vestland	Nysetelvi	Berdalsvatn (107,7), Riskallvatn (73) Total: 180,7	Østfold Energi (100)	Østfold Energi	1 Pelton	112	446,4
16	5	Sy-Sima	SR	1981	Eidfjord, Vestland	Numedals and Sima-vassdraget	Sysenvatn (938,7), Rembesdalsvatn (84) Total: 1022,7	Statkraft Energi (65) (Eviny (26,25), Sunnhordaland Kraftlag (8,75))	Statkraft Energi	2 Pelton	620	1637,1
17	5	Tyin	SR	2004	Årdal, Vestland	Tya-Rausdals-Utla- and Bergdals-vassdraget	Tyin (812,9) Mannsbergvatn (43,6) Krekavatn (32,7) Viervatn (24,9) Kyrkjevatn (16,6) Biskopvatn (11,2) Torolmen (10,2) Nedre Breibotnvatn (2,6) Total: 954,7	Hydro Energi (100)	Hydro Energi	2 Peleton	390	1462,4
SR = Storage Reservoir												

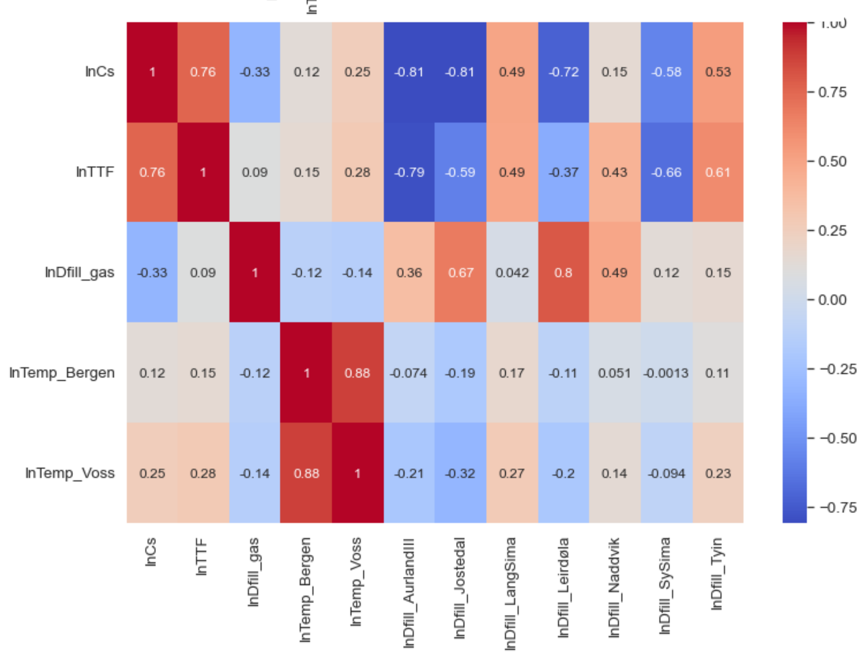
PS = Pumped Storage

Ownership, operator (NVE, 2020)
Installed generation capacity (Entso-E, 2021a, 2021b)
Average annual production, location, price area (NVE, 2022c)
Reservoirs (NVE, 2022a)
Waterways (NVE, 2023b)

Appendix 4. Correlation matrix.

The correlation matrices below show the correlation between the independent variables included in the model. Since the model is run for each individual power plant with the associated reservoir filling variable, it was not relevant to include the correlation between the reservoir fillings of the different power plants.



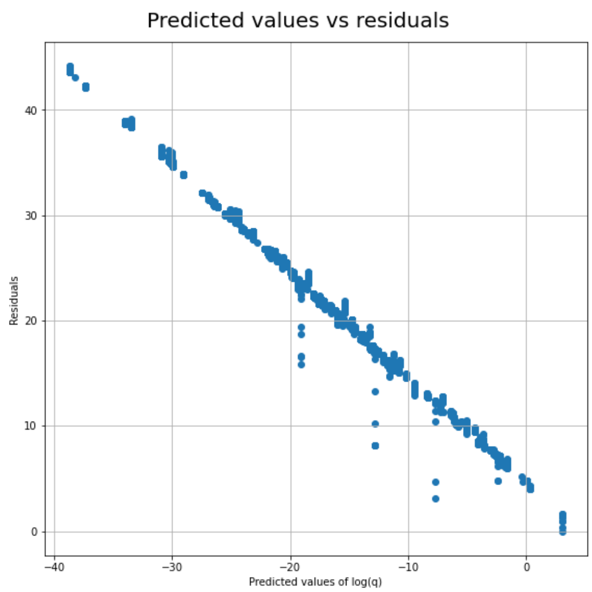


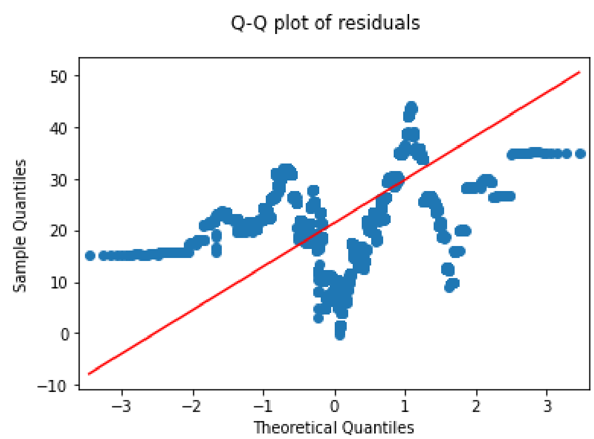
Appendix 5. MLE 4: Errors are normal and I.I.D

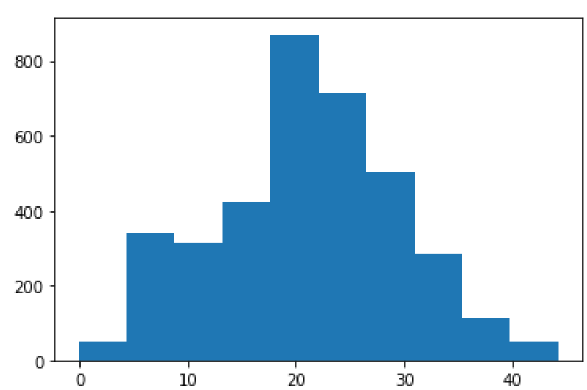
The three graphs below were obtained when we performed tests to ensure that the I.I.D assumption holds. The first graph is the predicted values vs residuals, the second is the Q-Q plot of residuals and the last is the histogram of residuals.

Tysso, Tyin and Jostedal had similar results. Therefore, we have only included the results for Tysso, to give a general impression of what the results for these three plants look like. Similarly, the results for Sundsbarm have been included below, as an illustration of the approximate results of the remaining plants except Tjodan. Tjodan is presented last, which has a slightly similar pattern as Sundsbarm but more volatility, a more visible pattern, and a skewed histogram.

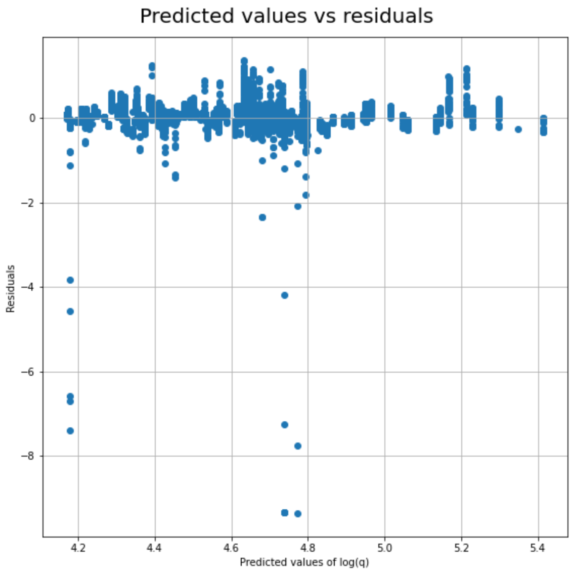
Tysso:

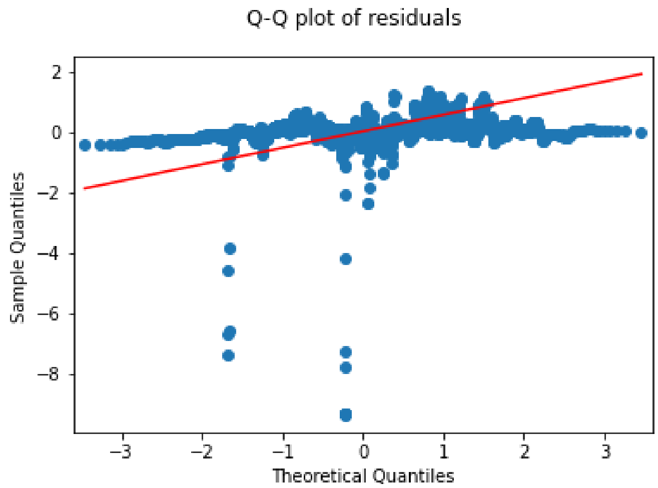


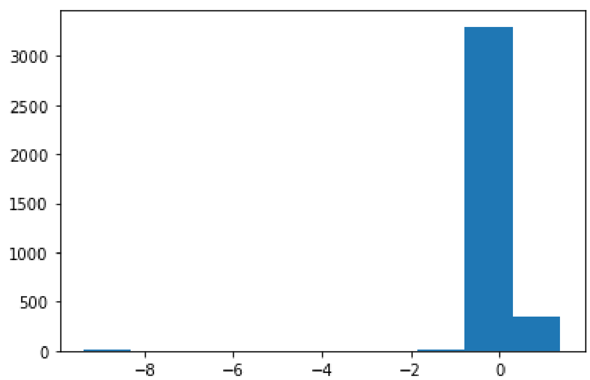




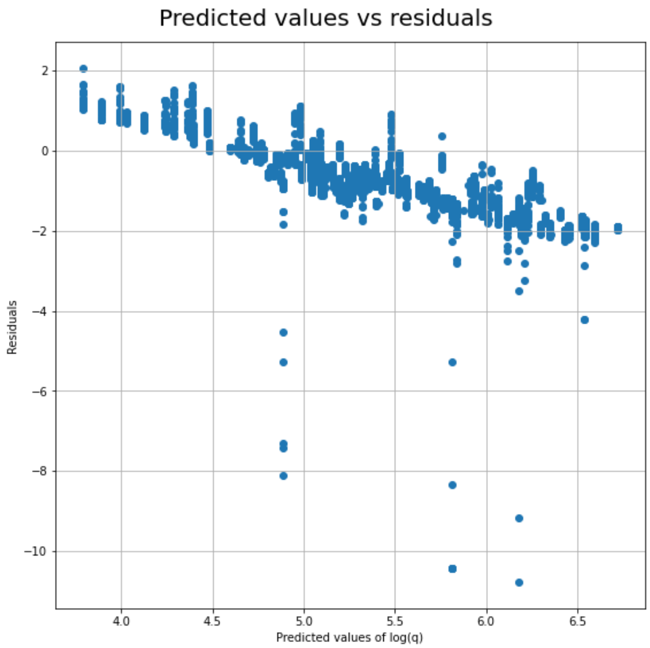
Sundsbarm:


Predicted values vs residuals
Residuals
Predicted values of log(q)

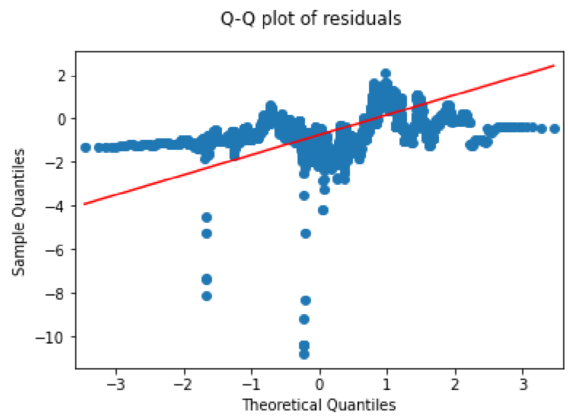

Q-Q plot of residuals
Sample Quantiles
Theoretical Quantiles



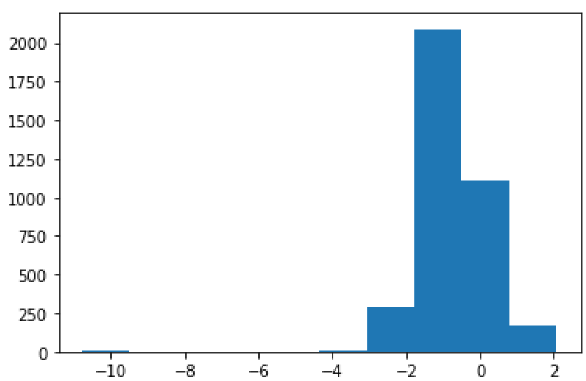
Tjodan:



Predicted values vs residuals
Residuals
Predicted values of log(q)



Q-Q plot of residuals
Sample Quantiles
Theoretical Quantiles



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