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The Impact of Production Taxes on Hydropower Production

An Analysis of Norwegian Distributional Taxes

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Abstract

Challenges in the power balance (Norwegian: effektbalanse) occur during peak load hours in the morning (07-11) and in the afternoon (17-19) during the coldest winter days (Thema Consulting, 2022). Hydropower offers significant flexibility in adapting to electricity market conditions, such as the power balance, but the introduction of the Norwegian high-price contribution (Norwegian: høyprisbidraget), or HPC for short, potentially complicates this flexibility.

The HPC is a 23% tax on the portion of the spot price above 0.7 NOK/kWh. The tax took effect for large hydropower producers on the same day it was announced, 28 September 2022. By being levied on only high-price hours, the tax reduces the relative profitability of producing during these hours. Given the uncertainty of future prices, this could change the allocation of hydropower production over time. Therefore, the HPC could lead to reduced electricity production in the hours with challenges to the power balance.

This study investigates the impacts of the HPC on the daily allocation of reservoir hydropower production. It specifically aims to answer the research question, "How does the Norwegian high price contribution affect the allocation of reservoir hydropower production throughout the day?" Given the modest size of the HPC and its monotonic characteristics, the hypothesis suggests a relatively small impact on production allocation.

The research utilises hourly data on production plans from the Norwegian Energy Regulatory Authority (RME), controlling for reservoir- and temperature levels, maximum installed capacity, futures electricity prices and European gas and -carbon prices. The study obtains estimates on hourly production using a standard Tobit model, with interaction terms between hourly dummies and the HPC.

The results indicate lower hourly allocation for daytime hours after the HPC came into effect compared to before it was introduced. The results align with our hypothesis and indicate that the allocation of hydropower production over different hours of the day is altered as an effect of the HPC. The result is useful for policymakers in understanding the implications of fiscal measures on energy production. This thesis contributes to the field by taking an econometric approach to the operational dynamics of hydropower under distributional tax measures, a topic with sparse previous literature.

Keywords: allocation, water, electricity, hydropower, reservoir, high, price, contribution, høyprisbidraget, production, excise, tax, hour.

Acknowledgement

I wish to thank my beloved father, Gustav Hansen, for always urging my critical thinking through hour-long discussions about chips, life, and everything in between. You have always pushed me to do my best, and I would not be who I am today without you. I wish you were here for me to show my gratitude. You will always be my best friend.

My mother, Bente Johannessen, has put in extreme amounts of time for me to have personal interests. Driving me to practice several hours every week, teaching me to care for animals, and always making my favourite food when I come home. All this simultaneously as running a farm, working, and raising seven children. In practice, you have taught me everything about equality. You are my security net.

Thank you to my supporting spouse, Torgeir Dahl Jørgensen. By example, you inspire me to live well and to be more pragmatic. You support me in all my endeavours, no matter what country they are in, and I trust that you will come and bring me back home. Life is better when I can get daily hugs from you.

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Table of Contents

List of Figures

List of Tables

Preface

This master's thesis marks the completion of my master's study in Applied Economics and Sustainability with a specialisation in "Environment, Climate and Energy Economics" at the Norwegian University of Life Sciences (NMBU). The thesis is written as a part of the research project Fairpower funded by the Research Council of Norway and coordinated by the Center for International Climate Research (CICERO, Retrieved 07.05.24).

The author of the thesis is currently employed by the Norwegian Ministry of Energy (ED), but the thesis is written independently of this work. The thesis is the individual work of the student alone and does not represent the viewpoints of any governmental institution. The background section (and only that section) of the thesis is read and commented on by one ED employee before delivery.

Data agreement

Data on planned production is provided by the Norwegian Energy Regulatory Authority (RME) under a resolution for the release of confidential information for use in the thesis. The confidential information includes information on installed capacity and planned production for the power producers. With authority under the Public Administration Act §13 (1970), the following conditions are set for the disclosure of confidential information for the master's thesis:

1. The information must be stored and handled in a safe manner.
2. Publication of results must take place in statistical form or by omitting individualising characteristics in other ways.
3. The data material must only be used by persons with a professional connection to the master's thesis and must not be passed on to others without consent from RME.
4. The provided data must be deleted no later than one year after the project ends, i.e. no later than 30 June 2025.

This has some implications for the publication of results in the thesis. Results from the analysis based on the confidential data will be published as part of the thesis with per bidding area as the highest aggregation level. The sections relevant for the data delivered by RME have been read and commented by RME before the thesis delivery.

1. Introduction

Challenges in the power balance[1] (Norwegian: effektbalanse) occur during peak load hours in the morning (07-11) and in the afternoon (17-19) during the coldest winter days (Thema Consulting, 2022). Deficits in the power balance may be more difficult to cover with imports in the future as more variable renewable energy is added to the European grid following the European Union (EU) ambitious climate targets (Retrieved 07.05.2024). Reservoir hydropower, which makes up a large part of power production in Norway, is often the most cost-effective alternative to provide supply-side flexibility (IEA, 2021). The Norwegian policy, the high-price contribution (Norwegian: høyprisbidraget), or HPC for short, might alter this flexibility, resulting in lower electricity production when it is most needed.

The HPC is a 23% tax[2] on the portion of the spot price above 0.7 NOK/kWh. The tax took effect for large hydropower producers on the same day it was announced, 28th September 2022. By being levied on only high-price hours, the tax reduces the relative profitability of producing during high-price hours. Given the uncertainty of future prices, this could shift hydropower production away from these high-price periods. In Norway's demand-driven power market, high prices usually indicate high demand hence, a necessity for production. Therefore, the HPC could lead to reduced electricity production when it is most needed. This makes investigating the effect of the HPC on hydropower production of uttermost importance for making informed policy decisions that are fit for the future electricity grid.

The main objective of this study is to investigate the effect of the HPC on Norwegian hydropower production. The thesis aims to answer the research question, "How does the Norwegian high price contribution affect the allocation of reservoir hydropower production throughout the day?" to which the thesis hypothesises production during load-peak hours to be lower after the introduction of the HPC than before. However, as the size of the HPC is small and its transformation is monotonic[3], the hypothesis is that the effect is relatively small. The thesis focuses on changes in reservoir hydropower production from a production-shifting perspective. To achieve this, the thesis implements measures to isolate and remove the effects of long-term impacts, such as investment behaviour.

This thesis starts by describing background information that is relevant to the later analysis on topics such as the Norwegian electricity system, hydropower production and hydropower policies. Then it introduces relevant literature before it delves into the theory behind hydropower production allocation and stating the thesis research questions. After this the data sources used and the process for attaining them are described, followed by the econometric approach taken. Results are presented and discussed before the thesis concludes with an examination of the research questions.

[1] Thema defines power balance as an equilibrium between production and consumption during peak load hours on cold days in the winter.

[2] Excise duty (Norwegian: særavgift)

[3] A monotonic transformation is where the order among the elements is preserved through the transformation. Here this means that if the price in one hour is less than the price in another hour, it will still be less than the other after the HPC.

2. Background

This section provides background information to the Norwegian electricity market and the role of hydropower within this market. In addition, it explains the policy in questions: the Norwegian high price contribution (HPC), as well as looking into other factors that might affect the analysis of the thesis. The goal of the chapter is to provide the information relevant to assess the attributes of the HPC.

2.1. Electricity in Norway

Power on the gird follows the laws of least, which makes it impossible to distinguish different power deliveries from each other. This makes electricity a relatively homogeneous good – fulfilling one of the conditions for a perfect market. However, one could argue that the primary energy source of the electricity, whether it be coal or renewable hydropower, affects willingness to pay. Electricity's differential from other goods is that it cannot easily be stored. Therefore, there must always be an exact balance between generation and consumption.

Transmission capacity

The balance between production and consumption must be true for the entire synchronous grid area, which Norway shares with Sweden and parts of Denmark. This means that the power system throughout this area has the same frequency (which is decided by the relationship between production and consumption).

In Norway, the state-owned company Statnett is the transmission system operator (TSO). The grid is divided into transmission-, regional and local distribution grids, typically with different voltage (Norwegian: spenning) levels (Ministry of Energy, Retrieved 07.05.2024 a). Norway's electricity market is divided into five bidding areas: NO1 (East), NO2 (South), NO3 (Central), NO4 (North) and NO5 (West). These zones are designated to account for variations in electricity generation, consumption, and transmission across different regions, giving variations in prices between each area. However, towards the north of the country the grid suffers from low transmission capacity and different voltages in the transmission grid compared to the rest of the country.

The capacity of the grid refers to the maximum amount of power that an electrical grid can reliably deliver to consumers at any given time. This means that the total capability of the grid infrastructure is decided by the one hour of the year with the largest transmission. In 2024 Norway has a transmission capacity abroad of about 9000 MW (Ministry of Energy, Retrieved 07.05.2024 a). This amounts to about 50% compared to the average hourly production in a normal year[4]. The transmission capacity corresponds to a theoretical potential of 80 TWh power transmission per year, but its utilization in practice is much lower (Ministry of Energy, Retrieved 07.05.2024 a). The capacity was significantly increased in the summer of 2021 when new cables to UK and Germany came into operation.

Norwegian power markets

For a long time, the Norwegian electricity market was subject to heavy political regulation, where the government determined the electricity price, based on the costs of production. In 1991, market-based principles for power sales were introduced. This started a deregulation of the Norwegian power market (NOU, 2023). A liberalized electricity market prevailed with competition between power producers and the possibility of trading power.

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[4] A normal year amounts to 156 TWh production (Ministry of Energy, Retrieved 07.05.2024 b).

The most defining characteristic of the power market is that supply must be equal to demand at each point in time to avoid outages. In Norway, electricity is traded in several different markets. The power market can be divided into the wholesale and end-user market. In the end-user market, purchases are made between small consumers and power suppliers. In the wholesale market the power suppliers trade on behalf of these typically small individual consumers, only here aggregated into larger volumes. Large industrial customers can also trade on behalf of themselves. Sellers to the wholesale markets are typically power producers. The wholesale market includes the day-ahead/spot market, intraday market, and balancing markets (Ministry of Energy, Retrieved 07.05.2024 d).

The day-ahead market is the electricity market with the largest volumes traded. Here, participants make bids and offers between 8-12h each day for delivery of power hour-by-hour the next day. Prices for each hour of the following day are made public between 12-13h. The price is calculated for each bidding area based on all the purchase and sell orders received and the transmission capacity available in each bidding area. After the day-ahead auction closes changes in weather forecasts and other unforeseen events can still happen, making actual production or consumption change from its position in the day-ahead market. This is where the intraday market comes in. Here, contracts are continuously traded up to one hour before the operation hour. Day-ahead and intraday trading takes place on the Nord Pool power exchange. Unforeseen weather events can still take place, and bottlenecks might occur. This implies that some imbalances cannot be handled in the intraday market. These must be taken care of in the reserve (/balancing) market. The balancing market is run by Statnett, the Transmission System Operator (TSO) and includes several different markets (Statnett, Retrieved 07.04.2024 a). The reserve markets are currently under structural changes and will not be described in detail here.

In addition to the electricity markets mentioned above market participants may also make financial/bilateral contracts for a specific volume and price for delivery of electricity in an agreed period. This includes options, future and forward contracts and electricity price area differentials (EPAD). These are often traded in larger European markets. Norway remains closely integrated with other Nordic and the wider European power market through transmission lines. Also, Norway are members of the European Economic Area (EEA), ensuring close cooperation with the EU. Because of this interconnectedness, the Norwegian power market must be analysed keeping in mind EU energy policies.

Electricity prices

As explained, the Norwegian bidding areas represent a geographical area. The price in the spot market is decided for the different markets by the supply and demand in each bidding area. When the supply decreases, the price increases, everything else equal. The same is true for higher demand. Spot prices do not necessarily need to differ between areas, but historically they have differed. The underlying cause of this is that the power situation differs from one region to another (NOU, 2023, s. Ch. 8), and bottlenecks in the grid between areas can stop the power from flowing from one area to another. Price differences between bidding areas give incentives for power to move to where it is most needed.

Power prices seen by end-users can be based on the spot price, fixed-price contracts, or something in between. In Norway, the share of each type depends on the type of consumer. Power-intensive industries typically use fixed-price contracts, while most households have power prices dependent on spot prices (Statistics Norway, Retrieved 07.05.2024). In addition to the power price end-user prices must account for grid tariffs, electricity tax, value-added-tax (VAT), and electricity certificate prices.

During the fall of 2021, electricity prices experienced a rapid increase resulting in higher prices, especially in the southern bidding areas. This trend is described for spot prices in greater detail in the section on “Day-Ahead Electricity Prices”. As explained in the Official Norwegian Report (2023) the new price situation created a shift in the distribution of income/cost for different groups. This was the foundation for the introduction of the power price subsidies, as explained in the section on “Other policies”.

Demand-Driven Power Market

The Norwegian power market can be described as a demand-driven power market where the market output is actively adapted to consumption patterns, rather than by the supply side. This is often characterized by low price elasticity in the demand for electricity and relatively higher elasticity of the supply side. Electricity is a necessity in modern societies, and numerous studies point to the low flexibility in the electricity demand. Electricity supply in Norway is highly dominated by reservoir hydropower which because of its storing ability is relatively more flexible in the short run than the electricity demand. In the long run, however the flexibility of reservoir hydropower supply is low as the total production is decided by the inflow to the reservoirs.

Because of the demand-driven power market the hours with high electricity prices are also the hours with the highest demand for electricity. That is, the hours with high prices are the hours where the need for electricity is the largest, and therefore the hours where production is most needed. If a policy has an effect of lowering production in these exact hours, the power system run the risk of not having enough production to meet demand, creating instability in the grid.

Thema Consulting (2022) states that challenges in the power balance[5] (Norwegian: effektbalanse) occur during peak load hours in the morning (07-11) and in the afternoon (17-19) during the coldest winter days and follows consumption peaks from households and commercial buildings. They also expect the issues with the power balance to occur more often towards 2050 due to a tighter energy balance[6] (Norwegian: energibalanse).

2.2. Hydropower production in Norway

Hydropower as a source of electricity

Hydropower, also known as hydroelectric power, is a renewable and primary energy source that generate electricity by converting the kinetic energy of water into electrical energy through generators. Hydropower can be divided into different types, based on the plant's operations. Reservoir hydropower is a type of hydropower generation that involves large dams storing water, which is released to flow through turbines to generate electricity. Run-of-river (ROR) hydropower generates electricity through turbines using the natural flow of rivers. Pumped storage hydropower plants pump water from a reservoir to another reservoir at higher elevation during times of low electricity prices, making the foundation for higher production from the higher reservoir. Other types of hydropower include tidal and wave power. This thesis mainly focusses on reservoir hydropower.

An important distinction between different types of energy sources is whether it is regulated or variable, which refers to how controllable the output from these energy sources is. Regulated energy sources can adjust output based on market conditions, such as demand. Variable energy sources are less controllable as their output depend on other factors, such as environmental conditions. Reservoir hydropower is considered as a regulated energy source, while ROR is placed in the group of variable energy sources along with wind and solar power.

Hydropower is based on water driving turbines again generating electricity. This makes electricity production from hydropower highly dependent on the water cycle where inflow vary, both from one year to another

[5] Thema defines power balance as an equilibrium between production capacity and consumption during peak load hours on cold days in the winter.
[6] Thema defines energy balance as the balance between energy production and consumption year by year.

and between seasons. Water inflow is highest when the snow melts during spring/early summer make up the majority yearly reservoir filling. The inflow normally declines towards the end of summer but increases again during the autumn. In the winter months inflow is generally very low (Ministry of Energy, Retrieved 07.05.2024 b). This sets restrictions on the supply of hydropower and are factors which is difficult to alter using policies. In practice, this means that total production long-term cannot be changed from the high-price contribution (HPC). Therefore, short-term allocation of production is a more interesting focus for this thesis.

Reservoir hydropower as a source of electricity

Unlike variable energy sources, reservoir hydropower is easily turned on and off from changing market conditions at low costs. This allows for flexibility in when to produce, making the elasticity of hydropower production relatively more flexible, thereby making it an interesting energy source for this thesis. Because of this ability to regulate production producers need to decide on *when* to produce based on the value the production gives for each point in time: the water value.

The main advantage of reservoir hydropower e is its natural storing capacity. Reservoirs allow a transfer of water from high-inflow periods to lower-inflow periods. However, like batteries, reservoirs have a limit on how much water and potential power they can contain. This constraints production and can alter the optimal decision to produce for hydro plants. If the reservoir is full, it runs the risk of running over, meaning that no electricity is produced from the overflowing water, providing no income.

Also, other constraints could be set on the production of electricity. E.g. water takes time to transport, and one might not be able to produce at full capacity instantly. Today reservoirs often exist linked through rivers with several other reservoirs, meaning that the production at one plant affects downstream plants. This is not accounted for in this analysis.

Hydropower in Norway

Norway's topography and numerous rivers make the country well-suited for hydropower production. The country has a long history of harnessing water resources for electricity generation dating back to the late 1800s when the first hydropower plant was built in Telemark (Norwegian Government, Retrieved 07.05.2024 a). The construction of hydropower plants in Norway accelerated during the first half of 19-hundreds. Many of the hydropower plants are in the western part of the country where the terrain is mountainous, and the water resources are abundant.

Production Capacity

Installed (production) capacity refers to the maximum amount of electricity that can be generated at any given time under optimal conditions. At the beginning of 2023, the Norwegian power supply had a total installed (production) capacity of 39 703 MW, of which 33 691 MW came from hydropower plants (Ministry of Energy, Retrieved 07.05.2024 b). The number of hydropower plants in Norway at the same point in time amounted to 1 769, of which more than 1240 is storage reservoirs.

Hydropower, and especially that from reservoirs makes up a large storing capacity in both Norway and Europe, providing flexibility to the grid in when to produce. Almost 50% of European reservoir capacity is in Norway (Statkraft, Retrieved 07.05.2024 a). Total reservoir capacity corresponds to 70% of annual Norwegian electricity consumption and the 30 largest reservoirs provide about half the storage capacity in Norway (Ministry of Energy, Retrieved 07.05.2024 b). As the world transition towards a greener economy the flexible characteristics of hydropower will be crucial as more intermittent energy is added onto the grid.

Much of the potential (production) capacity of hydropower in Norway is already exploited (NVE, Retrieved 07.05.2024 c). Also, much of the remaining hydropower potential is protected. This means that few new hydropower plants will be added to the grid in the period analysed in this thesis: 2021-2023. However, most of the reservoirs were constructed before 1990 (Ministry of Energy, Retrieved 07.05.2024 b) providing some potential for Norway to increase its hydropower capacity through upgrading existing hydropower plants to increase efficiency. In fact, installed capacity, has been slowly increasing over the past couple of years, as shown in Figure 2-1 below. The increase in production capacity can reflect increasing investments in the hydropower sector, which is not the focus of this analysis. Therefore, the analysis must take account for this in the analysis such that our data on production does not reflect the increase in installed capacity.

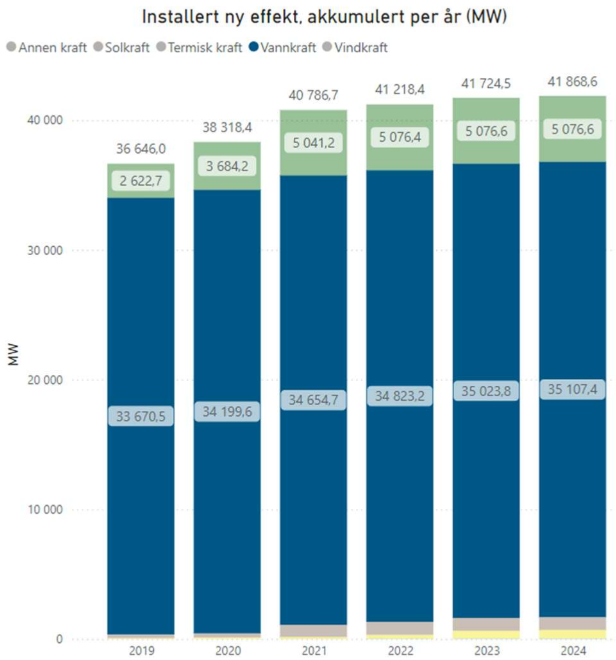


Figure 2-1. Installed capacity among Norwegian hydropower producers (blue area) for 2019-2024. Source: (Elhub, Retrieved 12.05.2024 a)

Hydropower Production

Today, hydropower is the most important source of electricity generation in the Norwegian electricity sector. Norway has the highest relative production of electricity from hydropower in the world. Production by hydropower plants is about 136 TWh in a normal year, which makes up about 88% of all Norwegian power production (156 TWh) (Ministry of Energy, Retrieved 07.05.2024 b). Globally, 16% of the total supply of electricity comes from hydropower (International Hydropower Association, 2022, s. 6). Together, this implies that changes in hydropower production are likely to alter overall electricity production in Norway, potentially having effects on the entire electricity market.

Hydropower production in Norway varies within a year. Figure 2-2 below shows the production of electricity from hydropower production and the net[7] consumption of electricity, per month, in Norway from 2019 to 2023. The figure shows how hydropower production follows the same seasonal pattern as net consumption of electricity. This emphasises the role of hydropower in meeting national consumption of electricity, and hence the severity of changes in the production of hydropower.

[7] Net consumption of electricity is by SSB defined as “the sum of all measured electricity consumption for primary industries, secondary industries, tertiary industries and households”.

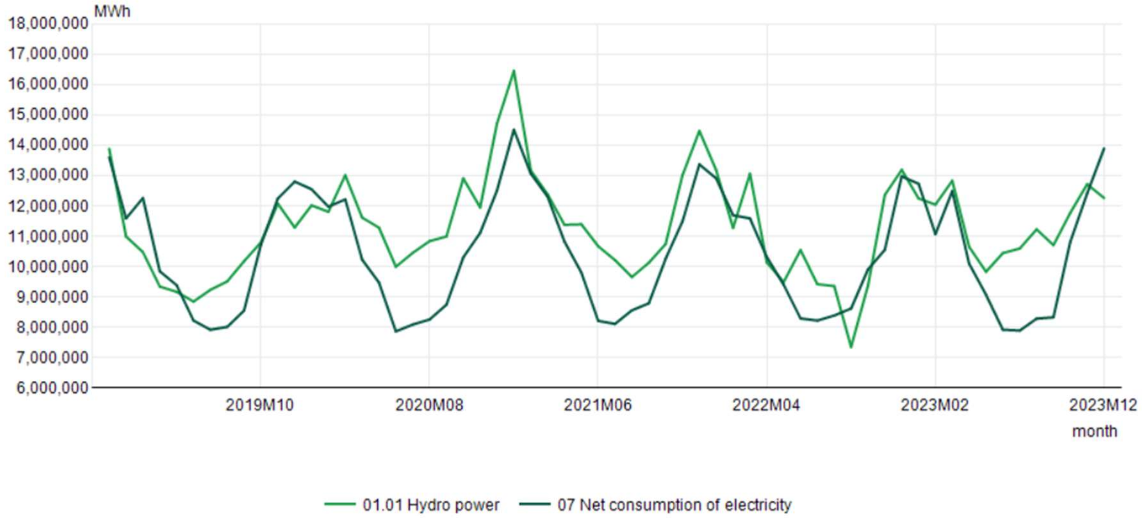


Figure 2-2. Production of electricity from hydropower production and net consumption of electricity, Norway, monthly, 2019-2023. (Statistics Norway, Retrieved 07.05.2024, s. Table 12824)

Size of Norwegian Plants

Table 2-1. Size and number of Norwegian hydropower plants. (NVE, Retrieved 07.05.2024 h).

Category (MW)	Number	Maximum output (MW) (norwegian: ytelse)	Average annual production ability (TWh)[8]
< 1	582	191	0.7
1-10	838	3114	11.1
10-100	265	10 021	43.6
≥ 100	84	20 404	81.8
TOTAL	1769	33 730	136,9
Pumps	32		-0.3

In Norway, most of the electricity production from hydropower plants comes from few, but large plants. From the Norwegian Water Resources and Energy Directorate (NVE, Retrieved 07.05.2024 h) the numbers for the size of the Norwegian hydropower plants are obtained, summarized in English in the table above. The table shows statistics of existing hydropower plants as of 31/03/2023. Notice that even though there are few hydropower plants in the largest size span (≥ 100), this group stands for about 60% of both maximum output and average annual production ability. Also, the plants in the two categories <10 MW account for 80% of the plants (number), but they make up only 8,5 % of average annual production ability and 10% of maximum output.

Lastly, observe that 32 pumps were registered, with an average annual production ability of -0.3 TWh, which is only 0,2% when compared to the total average annual production ability. The table shows that the average annual production ability of pumped hydropower is relatively small. This fact is supported by the monthly statistics from (Statistics Norway, Retrieved 07.05.2024, s. Table 12824) when measuring electricity consumption from pumped storage against hydropower production.

[8] Estimated based on water influx in the period: 1991-2020. (Norwegian: Midlere årsproduksjon)

As of September 2023, 88% of all hydropower plants in Norway are owned by the public, which mainly consists of the state-owned Statkraft (NVE, Retrieved 07.05.2024 a). Other large suppliers are Hafslund, Å Energi and Norsk Hydro.

Environmental concerns

The environmental concerns of hydropower, and regulations following from these are not accounted for in the analysis of this thesis. Hydropower is the renewable energy source which causes most deaths around the world per unit production (Our World in Data, 2020) and the most emission intensive energy source among the renewable energy sources. However, hydropower production emits substantially lower GHG emissions than non-renewable energy sources, but this factor plays a minor role as almost all Norwegian electricity production is renewable. More relevant for Norway is that hydropower production can affect biodiversity of areas of production as it alters water levels. Also, the transportation of hydropower in the electricity market causes large interventions of nature. Several regulations address these concerns and limit the negative impact on biodiversity. Thereby these regulations can affect the production levels of hydropower producers.

2.3. The Norwegian high-price contribution (HPC)

Following the spot price increase in the fall of 2021 the Norwegian government introduced a tax to redistribute more of the extra ordinarily high income from power production (Ministry of Finanace, 2022, s. 18). The tax, namely the high-price contribution (HPC) (Norwegian: høyprisbidraget) is a 23% tax[9] on the portion of the spot price above 0.7 NOK/kWh. The below presentation of the HPC builds on the explanation by the Norwegian Tax Administration (Retrieved 07.05.2024 b).

The HPC was announced as part of the presentation on the state budget on 28 September 2022 (Norwegian Government, Retrieved 07.05.2024 c), and took effect from and including that date for hydropower stations that own generators with a rated power output of 10,000 kVA or more (large producers). From 1 January 2023, it also included hydropower stations of at least 1 MW and licensed wind power plants. The policy is designed as an excise duty authorized under the regulation on excise duties (Regulation on excise duties, 2001). When introduced it was estimated, with a great degree of uncertainty, that the proposed tax will increase tax revenues by around NOK 16 billion annually.

Specifically, for power traded in the spot market, the HPC is 23% of the monthly average of price that exceeds 0.70 NOK per kWh. The average price is calculated based on income from power production per month, divided by the power production in the same month. The basis for the duty is the portion of the power price that exceeds NOK 0.70 per kWh. The specific formula for calculation is shown below.

$$\left(\frac{revenues\ from\ power\ production}{actual\ produced\ kWh} - strike\ price\right) * tax\ rate * actual\ produced\ kWh$$

By taking this monthly average calculation, the HPC can give incentives to produce at either very low prices or very high prices to optimize their income, thereby changing their bids to the spot market. However, undergoing market manipulation is not allowed under today's regulation and giving bids that does not reflecting firms marginal cost of production is an example of such market manipulation. To clarify this issue the Norwegian Energy Regulatory Authority (RME) provided an instruction for bidding under the HPC stating that "it may involve market manipulation, or attempts at market manipulation, to adapt bidding in order to optimize income within the calculation period for the high price contribution" (RME, Retrieved 07.05.2024 c,

[9] Excise duty (Norwegian: særavgift)

s. translated). Because of this clarification the thesis do not especially account for the above-mentioned changes to bidding strategies in this thesis.

The duty is calculated separately for electricity valued at the spot market price, licence power, and power in accordance with withdrawal rights and own power (Norwegian: egenstrøm). Other contracts and agreements relating to power are calculated as one. If the enterprise subject to the HPC owns several power plants in different pricing areas, the calculation is made per bidding area and then aggregated for the enterprise. Volumes are allocated to the bidding area where the power has been supplied.

Introducing a tax on production during high-price hours changes relative prices between hours and thus give lower economic incentives to produce during high-price hours. As the tax base is the *share* of the price exceeding 0,70 NOK/hour, the transformation caused by the tax is monotonic, meaning that the policy alone does not change what hour gives most revenue under no uncertainty. This implies that the economic incentives to produce are still the largest in the high-price hours, compared to low-price hours. Still, the relative difference in price between hours over time is altered, meaning that the allocation of production over time can be changed if there is a presence of uncertainty.

Along with the voting on the state budged the parliament decided on 14 December 2023 to terminate the high-price contribution with effect as of 1 October 2023 (Norwegian Tax Administration, Retrieved 07.05.2024 a). Power producers must still submit special tax notices for October and November, but the tax authorities will refund the tax paid for these two months. The discontinuity between the day of the vote and the publication date of the change makes the ending of the tax difficult to analyse. As explained in the section on “Specifics of the High-Price Contribution” this thesis takes steps to account for this issue.

The Norwegian state-owned company Statkraft, Europe’s largest distributor of renewable energy, warned that the HPC changes water values, thereby reducing incentives for sound disposal of hydropower. This was stated by Julie Wedege, Director for policy and ownership at Statkraft, as highlighted in a news-article in EnergiWatch (2023).

2.4. Other policies

In addition to the high-price contribution (HPC) the Norwegian government has introduced other policies affecting the electricity market. Here, some of them are introduced. Information on policies not mentioned here that hydropower plants are subject to, is available at the website of the Norwegian Tax Administration (Retrieved 07.05.2024 d) or at the Ministry of Energy (Retrieved 07.05.2024 c).

Power Price Subsidies

As a reaction to the price increase during the fall of 2021 and spring 2022, the Norwegian government introduced power price subsidies in December 2021 (Norwegian Government, Retrieved 07.05.2024 d). The subsidy applies to households with consumption below 5 000 kWh per month per meter. The amount is set as a percentage of the price difference between 0,7 NOK/kWh (excluding VAT) and the monthly average price at the power exchange. This percentage was 55% from December 2021 (inclusive), changed to 90% from 1 September 2022, and 80% from April 2023 (inclusive). From September 2023, the electricity subsidy is 90% and based on the average electricity price hour by hour in the local bidding area. The subsidy is paid by the grid company. In addition to the policy for consumer, there are several other support mechanisms towards the high electricity price – a full overview can be found on the website of Norwegian Government (Norwegian Government, Retrieved 07.05.2024 b).

Climate Policy

Energy systems are closely linked with climate policy, especially in the form of carbon pricing. One example is the effect of the EU Emission Trading System (ETS) on the Norwegian electricity network, to which hydropower is closely linked. The EU ETS is a tradable quota permit system for GHG emissions. This means that it sets a maximum quantity of allowed CO2 (equivalents) emissions for certain sectors within the EU and lets sector actors trade permits. This results in setting a price on carbon emissions, heightening production costs for actors with emissions in the affected sectors – resulting in lower profitability in the affected sectors. Lower profitability in emission intensive sectors makes it relatively more attractive to invest in the renewable sectors. As hydropower is a substitute to this energy, this can shift demand from non-renewable sources to hydropower. This higher demand again drives up the water value, yielding higher profits in the hydro sector. In the longer run this results in more hydropower producers.

Resource Rent Tax

Resource rent refers to the surplus profit earned from having exclusive access to the extraction of natural resources. That is, access above what would be earned in a competitive market. Resource rent tax aims to capture a portion of this surplus for the government and is typically imposed on the profits generated by companies engaged in resource extraction activities. Thereby, it is levied on the revenue earned from selling the extracted resources minus allowable deductions for expenses related to extraction.

In Norway, a resource rent tax (Norwegian: grunnrenteskatt) on hydropower production was first introduced in 1997 (Norwegian Tax Administration, Retrieved 07.05.2024 c). The tax applies to hydropower stations that own generators with a rated power output of 10,000 kVA or more in the income year. The rate of the resource rent has been adjusted upwards over time, lowering the profitability of hydropower facilities. From and including the 2021 income year, the ground resource rent tax was converted to a cashflow tax. The most recent change was in 2022 (inclusive), where the effective tax rate was increased from 37% to 45%. In addition to the resource rent tax, the hydropower plants must pay a natural resource tax (Norwegian: naturressursskatt) to the municipality and state governor.

While both the resource rent tax and the HPC relate to natural resource extraction, a resource rent tax is a form of taxation on profits generated from resource extraction, whereas the HPC is a tax on the revenues of resource extraction alone during periods of high electricity prices. Thereby, the HPC does not consider the costs of production. By also accounting for costs, the resource rent tax makes investments that were profitable before the tax also profitable after the tax, thereby considered as a neutral tax in theory if the tax rate is fixed for the entire lifetime of the investment. However, when the rate of the resource rent tax varies, the tax might lead to some changes in investments to the sector. As explained further up, this thesis takes measures to account for changes in investments to hydropower plants. Because of this, it can be concluded that it is not necessary to account for changes in the resource rent tax specifically in the analysis.

3. Literature review

The purpose of this section is to provide insight into previous research and analysis on the topic of taxing hydropower production. Few previous studies have been conducted on the topic of the effect of taxes on hydropower production, but a wide literature exist on describing the supply of hydropower.

3.1. Tax on Hydropower Production

The Norwegian electricity system is unlike any other electricity network in the world. One reason is that an exceptionally high share of total energy consumption comes from electricity (electric heating and electric cars/transportation). Few other countries have the same reliance on electric energy. Also, as in the background section, most of Norway's electricity production comes from hydropower. To the authors knowledge, no other countries rely as heavily on hydropower as Norway. The authors have not found other instances where a similar production tax on hydropower production is implemented. Hence, as few countries have these types of taxes, there is also close to no analysis on the topic of taxes on hydropower production. One idea would be to look at taxes on other energy sources. However, the results would not be applicable, as the characteristics of reservoir hydropower do not resemble other energy sources. Not having supporting literature to look to has been a challenge when writing this thesis.

Excise Taxes

A study conducted by Thema Consulting (2022) on behalf of KS investigated the economic consequences of the tax proposal of the resource rent tax and the high-price contribution for municipal and county owners. They find that the tax proposal directly affects both the yield and indirectly the equity value of the owner municipalities /counties. The tax proposal is estimated to reduce the total capital by 24% of the equity value, amounting to 70 billion, of which NOK 22 billion results from the high-price contribution (HPC). They expect the dividend level to fall 25-30% due to the tax proposal.

The NOU (2019) on taxation of hydropower plants also provides some useful information in this context. The main task of the report is to assess whether the current hydropower taxation is an obstacle to economically profitable measures for society in the power sector. They divide taxes into two general groups: profit-based and gross taxes, which refer to the tax's dependence on profitability. They place production taxes in the second group. They state that production taxes can be designed as a value-based tax or as a quantity tax, of which the high-price contribution would fall in the first category (NOU, 2019, s. 87). They state that gross taxes result in the companies will assess investment and operating decisions differently with tax than in a situation without.

Amundsen, Andersen, & Sannarnes (1992) investigate rent taxes on Norwegian hydropower generation. They analyse the effects of six different tax systems on hydropower plants, including an excise tax like the high-price contribution (HPC). They find that using excise taxes helps avoid problems with cost-consciousness. However, they are not very neutral to investments, as they directly affect the revenues earned from production without differentiating on the economic rent generated by each power plant.

3.2. Explaining hydropower supply

Førsund (2015) in the book "Hydropower Economics", provides a comprehensive examination of the economic aspects related to hydropower production. The author addresses various economic factors tied to hydropower generation, including cost structures and allocation of water across periods. He also addresses how technical and environmental considerations impact the economics of hydropower. The book provides a theoretical framework for analysing hydropower supply from an economic perspective, which the thesis utilises and explain in greater detail in the Theory-chapter.

Jahns, Podewski & Weber (2020) divides the literature on modelling the operation/bidding behaviour of hydro reservoirs into four groups: 1) simple parametric functions, 2) econometric approaches, 3) stochastic- and 4) deterministic optimisation approaches. The literature is vast, and this thesis will only mention parts of the knowledge available. As the goal of the thesis is to explain the relationship between variables, and not on optimising production or bids ahead of time our focus in this section is more on the econometric side. However, elements from stochastic optimal approaches must be included to explain the relationship. This chapter only investigates research from Norway or the Nordic setting to limit the search.

Econometric approaches

Among studies with econometric approaches, the article by Birkedal & Bolkesjø (2016) explains how various economic factors influence the weekly dispatch of regulated hydro in Norway. The authors analyse the question using a simple OLS model, including the explanatory variables hydrological balance, inflow, temperature, power prices, price expectations, and short-run marginal costs (SRMC) for coal power generation. Upon finding signs of endogeneity between Norwegian power prices and hydropower production, they expand the OLS into a 2SLS model, using German electricity prices as an instrument variable (IV) for Norwegian electricity prices. Results indicate a significant impact on short-run hydro supply of hydrological balance, inflow, temperature, SRMC of coal power generation, and power prices. Thereby, the findings suggest that a few predictable determinants can explain a substantial portion of the variation in weekly hydro supply. Model results for the entire sample show that a 1 % increase in the power price would increase the supply by 16,8 GWh. By coupling the estimated model (in a simpler OLS-version) with observed values of hydropower generation, they find an average absolute deviation of 13,6 % but conclude that adding a lag structure to the model can improve the model's predictive power further.

Jahns, Podewski, & Weber (2020) develop different econometric approaches and combine them with fundamental models. They investigate the supply curves for hydro reservoirs in Norway. The paper formulates four different hypotheses for the supply curves of hydropower. They test these empirically using different model specifications. By estimating the various model variants to Norwegian data from 2016 to 2018, and then testing them on 2013 data, they confirm their hypotheses'. They find that the water value depends on the deviation from the seasonal equilibrium reservoir filling level and the variable costs of coal-fired power plants.

The master's thesis by Løfgren & Ingstad (2023) investigates the development of water values for hydropower production as a result to the 2021 energy price shock. They estimate water values using a double censored Tobit model, including reservoir filling, the TTF day-ahead gas price, the European carbon spot price, European gas storage and temperature deviations from a historical mean.

Stochastic optimisation approaches

Stochastic dynamic programming (SDP) and stochastic dual dynamic programming (SDDP) are both stochastic optimisation approaches. These approaches are often well used for modelling energy systems while accounting for uncertain variables like inflow, but frequently entail considerable computation time. A widely used SDP approach used in the Nordic context is Samkjøringsmodellen. Wolfgang et al. (2007) for SINTEF on behalf of the Ministry of Energy (ED), investigates the reservoir disposal before and after the 1991 deregulation (Norwegian Energy Act). They use "Samkjøringsmodellen" to solve their electricity market model (EMPS) optimisation problem. SINTEF by Wolfgang, Naversen, & Mo (2022) on request from the ED, performed a similar model in their assessment of the power situation in 2021-2022. Using Samkjøringsmodellen to investigate optimal reservoir water use in the last half of 2021, they found that hydropower producers (HPPs) underestimated both prices and the water value. The consequence of this was higher production than was socially optimal.

Aasgård et al. (2017) present a methodology for price-taking hydropower producers to optimise bids to the Nordic spot market. They do this by setting up a stochastic model in which hydropower producers optimal production schedules are found by maximising 1) the short-term revenues from selling power and 2) the value of water left in the reservoirs at the end of the horizon, 3) less the costs related to start-ups. Also, they point out that other stochastic parameters such as load, maintenance and prices in different markets may be included in the model in the future. They investigate how uncertainty in inflow can affect bid curves using stylised inflow uncertainty. Results show that the production strategy is affected by inflow uncertainty making bids better reflect the true opportunity costs. They also state that flexibility among downstream reservoirs is reduced by having multiple reservoirs along one riverbed.

Gjerden et al. (2015) investigated hydrothermal scheduling in Norway using stochastic dual dynamic programming (SDDP), where each hydro reservoir is modelled individually. By comparing the results of an SDDP model with the results of an aggregation/disaggregation model, they found SDDP to be computationally heavy and disadvantageous for system simulation when using historical inflow.

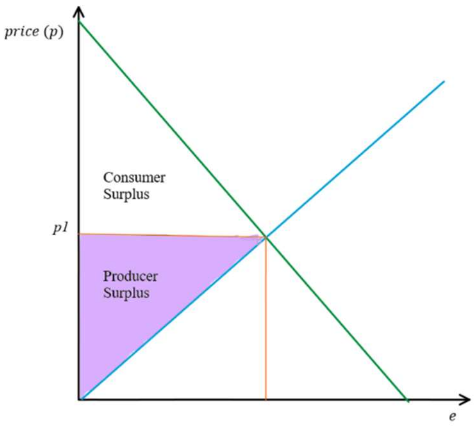
4. Theory

This thesis investigates how the high-price contribution (HPC) alters hydropower-producing companies' (HPPs) production decisions. To do this, the thesis describe how production decisions are made. Second, the concept of taxes on electricity production is introduced, then analyse how such taxes affect the production decisions. Any analysis of hydropower production decision needs to be founded on the physical characteristics of hydropower. The chapter takes base in the explanations in Førsund (2015, s. 15).

An alternative approach to investigating this is to ask HPPs to see their optimisation mechanisms or explain how decisions are altered. However, this is often highly confidential information, and there is often a discrepancy between communication and what is happening in the marketplace. Therefore, this thesis takes the approach of first building a theoretical argument and then testing the hypothesis empirically.

4.1. Hydropower Producers' Production Decisions

Profit Function



The goal of economists is often to maximise the social welfare of a market. That is, the sum of consumer benefits (CB) and producer benefits (PB), as shown in Figure 4-1. However, the focus of this thesis is not on social welfare, but on the producer surplus as this is the variable of interest for hydropower producers. By making this simplification the focus of the analysis is described in a simplified manner as the purple area in Figure 4-1.

Figure 4-1. Simple illustration of supply and demand for electricity from hydropower. Here, p is the price and e is the hydropower produced for that period.

As discussed in the background section, the majority of hydropower producers are owned by the government in some form. However, most are registered as commercial firms and, for all practical purposes, act like private companies. From this, it can be assumed that HPPs maximise the producer benefits in the form of production profits. Profits at time t are described as revenues minus costs, both at time $t = 1, 2, \dots, T$.

$$\pi_t = p_t e_t - C e_t \qquad (1)$$

Profits depend on p_t, electricity prices at time t, multiplied with e_t, the electricity produced from regulated hydropower at time t (flow variable). Note that p_t is here the equilibrium price in the market at the relevant period, not the inverse demand function giving consumers marginal willingness to pay. The production of electricity from regulated hydropower, e_t, is measured in MWh and can be described as a function of the release of water during one period, r_t, measured in cubic meter(m^3), and the gross head of the reservoir, which is "the vertical height from the upper level of the dam to the outlet of water from the turbine" (Førsund, 2015). The head is again affected by the release of water for production itself, but this is not accounted for in this analysis. To simplify the statement that the produced electricity from regulated hydropower is equal to the release of water during the same period can be made. That is: $e_t = r_t$, which implies that $MWh = m^3$. Each reservoir also has a production capacity, $\bar{e}$, which gives an upper limit on the electric energy (MWh) that can be produced at each point in time. The capacity is decided either by 1) the maximal water flow of the feeding pipe, 2) the turbine capacity or 3) the transmission capacity from the plant, of which point two is often the most restrictive. This analysis assumes that the production capacity constraint $e_t < \bar{e}$ is not binding.

Total costs are described as production (e_t) multiplied with marginal costs (C). Hydropower production have high initial investment, but low marginal costs as production is easy to turn on and off. The expression above assumes that capacities are present and fixed, meaning that only variable costs (costs that vary with the level of output) should influence current operations. This is a reasonable assumption as the time horizon of question for the analysis is short, and there is taken steps to leave HPPs with capacity improvements out of the data used for the thesis. Also, most of the potential for hydropower in Norway is already exploited as previously explained. In this analysis the input to production is water, which is not bought on a market but given to us as a natural renewable resource. Førsund (2015) states that empirical information indicates that variable costs can be neglected in an analysis on hydropower production as the input to production, such as number of employees and maintenance, do not depend on the output. Following Førsund's this thesis assumes that there are zero variable costs and remove the cost term from the equation, leaving the profit function:

$$\pi_t = p_t e_t \qquad (2)$$

Production over time

Hydropower producers cannot control inflow into the reservoirs and must take this as given in the analysis. This means that the key question in hydropower production, made possible by storage capacity and flexibility in when to produce, is the time-aspect, whether to produce the available water in the reservoir now or later. Producers allocate production (choose e_t) such that Π, the net present value (NPV) of all single-period profits, is maximized. This thesis will focus on a finite two-period setup: the now and the future. That is $t = 1$ represents the present time-period while $t = 2$ represents the future. In this setup discounting can be disregarded for simplification. This analysis use discrete time as all practical applications of hydro production takes place within discrete time units. With this the maximization problem can be written as in formula 3 below. The formula rests on several conditions that will be explained in the following sections.

$$Max_{e_1,e_2}\, \Pi \;=\; Max \sum_{t=1}^{2} \pi_t \;=\; Max \sum_{t=1}^{2} p_t e_t \;=\; Max\,\{\, p_1 e_1 + \, p_2 e_2 \,\} \qquad (3)$$

Regulated hydropower has an opportunity cost, named its water value, as "production today means sacrificing the potential to use the same water for production in the future" (Førsund et al., 2005). These are the profits companies forgo in the future by choosing to produce today. The water value can also be regarded as the increase in producer surplus of getting one more unit of water. Observe that the expression above is a function of only p_t and e_t. This means that future profit depends on the electricity prices in the future. When looking at the spot market this means that the water value is affected by the bidding area in which the production takes place, and again factors that affects that bidding area. In a market without market power, each producer is not able to affect the price in that market. That is, the price is outside the control of the HPP. However, two recent master's thesis find indications of market power among Nordic and Norwegian HPPs (Øien, 2019) (McDermott, 2020). The water value also depends on todays and tomorrows' production, which again is dependent on the weather, and where in the waterway they are located.

Constraints

The maximization problem is only constrained by the total inflow during the period., the way it is displayed here. This is that the sum of production in all periods (T) cannot be higher than the total inflow during the same period.

$$\sum_{t=1}^{T} e_t \leq W \qquad (4)$$

In a two-period setting this is that the production in period one, e_1, and the production in period two, e_2, together cannot exceed the total inflow during all periods, W.

$$e_1 + e_2 \leq W$$

If the constraint is not binding, i.e., $e_1 + e_2 < W$, the Lagrange multiplier must be equal to zero. That is, if the amount of water increases, the producer surplus wouldn't get any higher. In this simple setup with overflow of water and no costs related to wasting water, the price in both periods must be equal to zero when there is abundance of water.

Reservoir constraints

There are several other constraints that explain the allocation of water over time more realistically. Still, the topic of this thesis is not to explain the allocation of hydropower production over time to great detail, but how the allocation is changed due to the high-price contribution (HPC). This allows us to take a simplistic format when explaining the setup around the changes.

The setup does not consider that the quantity available for production in one period depends on the water in the reservoir. The amount of water in the reservoir is dependent on several different factors: inflow, rainfall over the reservoir, evaporation, seepage (infiltration losses) and overflow (spillway). Inflow is again affected by the weather and other reservoirs upstream in the same waterway. In a cold country like Norway, it does not need to specially account for evaporation, and seepage and rainfall are neither considered. This analysis assumes that the production of electricity is efficient (i.e. no overflow), as it is not economically rational if prices are positive. Also, the water in the reservoir today depends on past production.

We can mathematically express the water in the reservoir at the end of period t, R_t (stock variable), as a reservoir constraint. That is, R_t must be equal or less than the reservoir level at the end of the period before, R_{t-1}, plus inflow in the current period, minus the release of water for production during the current period, r_t. As it is assumed that $e_t = r_t$ the constraint becomes: $R_t \leq R_{t-1} + w_t - e_t$. An inequality in the equation would imply that there is overflow. Here, w_t is the inflow during one period.

Also, it could be considered adding the condition that the reservoir filling must also be below the known maximum reservoir capacity due to physical reasons. That is: $R_t \leq R_{max}$. In such a constraint id would be important to consider both < and =, that is, if the constraint may be binding (we would like to save more, but not possible) or it may not be binding (capacity is more than big enough).

Lastly, reservoirs can be required to keep a minimum level minimum reservoir capacity due to environmental and security reasons. That is, $R_{min} \leq R_t$.

Uncertainty

Until now the feature of uncertainty in the modelling of the optimal production problem have been neglected. Equation 3 showed that allocation of production is highly dependent on prices today and in the future. However, the production decision is made in the current period while the future price is known only by predictions. This uncertainty of price affects the production decisions. The best option in the current period is to formulate an optimal production plan by maximising the *expected* sum of producer surpluses. Below, the decision problem is reformulated, evaluated in period one under uncertainty. Here, E is the expectation and p_2^U is the stochastic price in the second period. p_2^U is assumed to have a known distribution that is period specific. In the setup bellow the price in the current period is regarded as known. As described later in the section on data sources the price today is also uncertain as the market electricity price is obtained only after all bids are received. This uncertainty is disregarded for the sake of simplicity here.

$$Max_{e_1,e_2}\, \Pi = Max\,\{\, p_1\, e_1 + \, E(p_2^U)\, e_2 \,\} \qquad (5)$$

The sources of price uncertainty are many. Weather conditions can change rapidly, affecting power demand through the temperature or the power supply through the inflow. The situation in other countries might also affect demand through our transmission lines. Uncertain weather can also affect other production sources such as wind and solar directly, and the transmission system itself through storms creating fallouts and changing the maximum capacity of the network. To simplify the calculations to the topic at hand this thesis focus only on price-uncertainty, thereby not explicitly accounting for the fundamental reasons behind the uncertainty.

4.2. How is production changed from the high-price contribution?

To now the thesis has looked at how HPPs make production decisions. Now the thesis investigates how are hydropower-producing companies' (HPPs) decisions about production altered because of the high-price contribution.

Intuition behind taxes

To understand how the high-price contribution affects hydropower production one first need to understand how the tax works. As explained in section 2.3, the high-price contribution (HPC) is a tax on production in hours where the price is 0,7 NOK/kWh or higher per hour. By reducing the marginal revenue from production to supplier the policy reduces the profitability of producing in high-price hours. By reducing the profitability of production, it overall also reduces the profitability of investments in hydropower production. Especially, it disincentivises investments that upscale generators so that the maximum production per hour is larger, that is, investments that can increase $\bar{e}$. These last two effects are stronger the longer the policy is in place, but they are not the focus of this thesis.

The changes to the market for one hour are illustrated for a static setup in Figure 4-2, as if the producers of electric energy consisted of only hydropower producers. The supply curve looks different to the earlier presented figure because here HPPs consider the water value when deciding production bids. The original supply is illustrated with the dark blue line. After the HPC is introduced, there are no changes to supply while the price is below the 0,7 threshold. However, when the price exceeds 0,7 NOK, the supply curve pivot as the marginal revenue seen by producers is lower than before the HPC was introduced. In the market this results in a steeper supply curve and a lower quantity of electricity from hydropower is supplied for the same price, ceteris paribus.

Adding the demand curve to the market, which here can be thought of as the residual demand for hydropower, one can see that there is no change to the equilibrium if the price is below the 0,7 threshold. However, when the demand crosses the supply curve above 0,7 the equilibrium shifts to a lower quantity supplied at a higher price. The size of these shifts will depend on the elasticity of the two curves. As shown in the background section, the *short-run* elasticity of demand for electric energy is inelastic, and the production of hydropower is relatively flexible in the short run. This can lessen the effects of the reduced production. The size of the tax is the distance between the two blue lines. The tax is zero when the price is below 0,7 NOK. The figure explains changes in the full market for hydropower. However, each single producer makes up only a small part of this market. For the individual producer the supply curve will be approximately horizontal up to the production capacity where it will be approximately vertical. For the individual suppliers it can be optimal to produce zero (corner solutions) for singular hours.

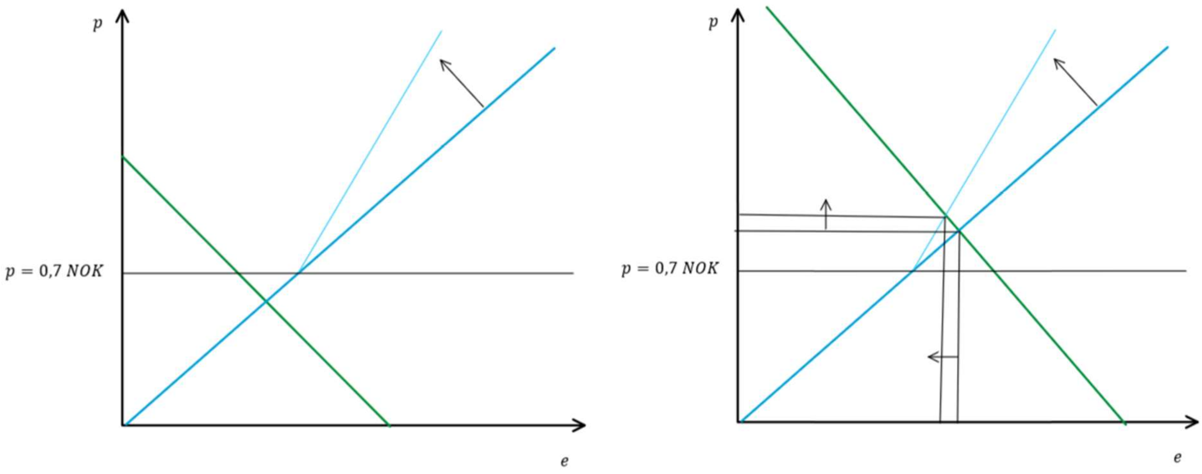


Figure 4-2. Effects in the market for hydropower electricity resulting from the high-price contribution. Left: low residual demand. Right: High residual demand. D: demand curve. S0: original supply curve. S1: new supply curve. The figure assesses the effect of HPC ceteris paribus and does not consider other policies e.g. the power price subsidies.

The setup above shows the effect in a market of production from hydropower and for the residual demand for hydropower *for one period*. The effects for the electricity market in total are probably not as strong, but it is reasonable that some of the same effects on the quantity supplied and the price will be observed as hydropower makes up a large part of the total electricity production in Norway. The figure displays the market for hydropower as only one period, while in the electricity market the electricity markets of different periods must be evaluated together. That is, higher production today leaves less water to produce tomorrow.

In the optimization problem

Section 4.1 expressed the maximization problem for optimal production for one hydropower producer, in two periods under uncertainty of future prices and inflow. Here, this formula is updated to also capture the effect of the high-price contribution as described in the section above. The goal is to observe if the optimal allocation of production between the two periods changes as a result of the HPC. The section derives the production allocation under four different scenarios. First looking at the case with no uncertainty, then with price uncertainty. In both circumstances, the case where the HPC is present and where it is not is compared. The different setups can be illustrated using Figure 4-3.

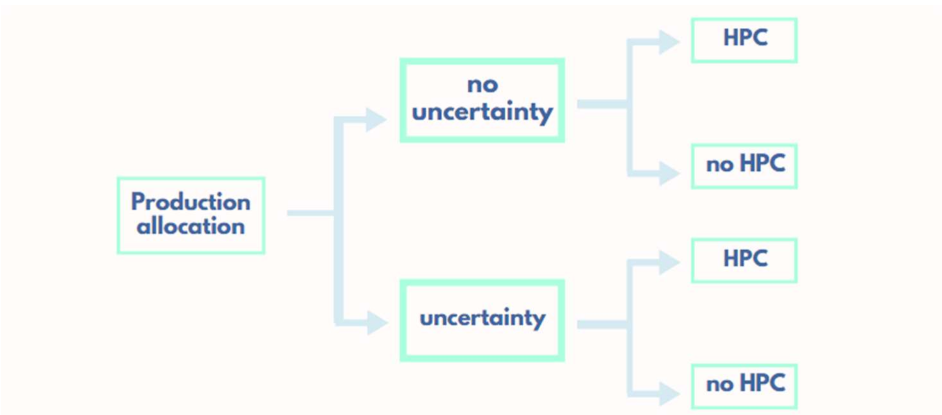


Figure 4-3. Illustration of the different situations considered when investigating the effect of the high-price contribution on the allocation of production over time.

We set up the optimisation problem thinking of period one as the current price which set to be below the 0,7 threshold (P) for simplicity, that is $p_1 < P$. Period two is the future where there is a possibility that the price is above 0,7 NOK. The price in the current period is known, but there exists uncertainty of the future price. This uncertainty gives two different possible outcomes for the formula. If the price is above 0,7

NOK/hour the HPC reduces the price seen by producers per unit produced. That is, only $1 - tr$ (100% minus the tax rate) of the part of the price above 0,7 NOK is attained by producers. The tax does not consider the costs of production and included on the revenue side of the of the maximisation problem. The expression can be written as bellow, where $tr = 0{,}23$ and $P = 0{,}7$.

$$Max_{e_1,e_2}\, \Pi \; = \; Max\,\{\, p_1e_1 + (P + (1 - tr)(p_2^H - P))e_2 \,\} \quad (6)$$

If the price is below the 0,7 NOK/hour the HPC does not apply, and the profit function is as before.

$$Max_{e_1,e_2}\, \Pi = Max\,\{\, p_1e_1 + \, p_2^L e_2 \,\} \qquad (7)$$

Without uncertainty

Following the logic of the policy from above the updated maximization problem is explained here. For the setting under no uncertainty, the thesis takes the assumption that the price in period two is higher than that of period 1 to visualize allocation. That is, under no uncertainty $p_1 < p_2$ is true for all possible values of p_2. This can be because there might be the case when there is abundance of other intermittent energy sources in the first period, e.g. because of seasonal variations.

Without HPC

When HPC is not present the maximization problem is the same for both high and low prices in the second period and p_2 is denoted without its H/L subheading.

$$Max\,\{\, p_1e_1 + \, p_2e_2 \,\}$$

Where p_1, p_2 is known and we have the constraint: $e_1 + e_2 \le W$

This gives us the Lagrange function:

$$L = p_1e_1 + \, p_2e_2 - \lambda(e_1 + e_2 - W)$$

We obtain the first order conditions (FOCs):

1. $L'_{e_1} \le 0 \;\; \{= 0 \; if \; e_1 > 0\}$
2. $L'_{e_2} \le 0 \;\; \{= 0 \; if \; e_2 > 0\}$
3. $L'_{\lambda} \;\; \le 0 \;\; \{= 0 \; if \; \lambda > 0\}$

As we look at only the two-period setting it will be economically optimal to produce all the water. Hence, we assume that $\lambda > 0$. This gives: $L'_{\lambda} = 0$.

We get:

$p_1 - \lambda \le 0$
$p_2 - \lambda \le 0$
$e_1 + e_2 = W$

In our simple setup it will be optimal to produce all the water in one of the periods. The reason for this is our lack of reservoir constraints. As there are no restrictions on when we produce, HPPs will chose to produce everything when the price is highest. In this two-period setup the water value is decided by the period with the highest marginal revenue.

Now, an interior solution ($e_1, e_2 > 0$) would imply:

$$p_1 = \lambda = \lambda = p_2$$
$$p_1 = p_2$$

However, from above we have that $p_1 < p_2$ indicating that $e_1 = 0$. If $e_1 = 0$ we must have that $e_2 > 0$ from the third FOC. Specifically, we get that $e_2 = w$. Here, the water value is higher than the price in the first period and HPPs will choose to save all the water.

For example, $p_1 = 0{,}69$ and $p_2 = 0{,}71$ ($p_1 < p_2$) both in NOK/kWh, Under no reservoir constraints producers will choose to allocate all production to the period with the highest marginal revenue. Hence, all production will be allocated to the second period.

With HPC

After the introduction of HPC there are two possible outcomes; either the price is above the threshold P, or it is below. The maximization problem for a price bellow P is explained by equation 7 above. This is the same maximization as in the case without the HPC, yielding the same production. Hence, without uncertainty of future prices the allocation is the same as without HPC. However, when the price is above P the maximization problem becomes:

$$Max\,\{\,p_1 e_1 + \,(\mathrm{P} + (1 - tr)(p_2^H - P))e_2\,\}$$ Where p_1, p_2 is known, P is the threshold for the tax (0,7) and we have the constraint: $e_1 + e_2 \leq W$
This gives us the Lagrange function: $$L = p_1 e_1 + \,(\mathrm{P} + (1 - t)(p_2^H - P))e_2 - \lambda(\mathrm{e}_1 + \mathrm{e}_2 - \mathrm{W})$$
Working with the FOCs described above we get: $p_1 - \lambda \leq 0$ $(\mathrm{P} + (1 - t)(p_2^H - P)) - \lambda \leq 0$ $e_1 + e_2 = W$
An interior solution ($e_1, e_2 > 0$) would imply: $$p_1 = \lambda = \lambda = (\mathrm{P} + (1 - tr)(p_2^H - P))$$ $$p_1 = (\mathrm{P} + (1 - tr)(p_2^H - P))$$ Setting in $tr = 0{,}23$ and $P = 0{,}7$ we get: $p_1 = 0{,}7 + 0{,}77\,(p_2^H - 0{,}7)$ From above we have that $p_1 < p_2$. We don't know the exact relationship between p1 and p2, but we will have that $p_1 < 0{,}7 + 0{,}77\,(p_2^H - 0{,}7)$ as long as $p_1 < p_2$. This again results in all production being allocated to the first period, leaving $e_2 = 0$.   Taking the extreme example $p_1 = 0{,}69$ and $p_2 = 0{,}71$, both in NOK/kWh, we get the relationship: $0{,}69 < 0{,}7077$. Hence, all production is still allocated to the second period.

We observe that under no uncertainty the optimal allocation of water in the two periods does not change neither when the price in the second period is below OR above the 0,7 threshold of the high-price contribution. One condition for this is that the relationship between the prices stay the same, that is $p_1 < p_2$ and $p_1 < P$. This highlights the monotonic characteristic of the tax.

With uncertainty

Following the logic of uncertainty and the policy from above we have the maximization problems below.

Without HPC

$$Max\,\{\,p_1\,e_1 + \,E(p_2^U)\,\mathrm{e}_2\,\}$$ Where p_1, is known and we have the constraint: $e_1 + e_2 \leq W$
This gives us the Lagrange function: $$L = p_1 e_1 + \,E(p_2^U)e_2 - \lambda(\mathrm{e}_1 + \mathrm{e}_2 - \mathrm{W})$$
Working with the FOCs described above we get: $p_1 - \lambda \quad\; \leq 0$ $E(p_2^U) - \lambda \leq 0$ $e_1 + e_2 = W$
In this case, the allocation of water depends on the relationship between the marginal revenue from the two periods, p_1 and $E(p_2^U)$, but now the price for period 2 is uncertain. To find the expected value of a discrete random variable, X, we simply multiply each value of the random variable, x,with its probability, $P(x)$. Then we add these products for each of the value of the random variable. That is: $$E(X) = \sum x P(x)$$ For simplicity we assume that there are two possible values of the random variable, p_2^U, with equal probabilities. This gives:

$$E(p_2^U) = 0{,}5\, p_2^L + 0{,}5\, p_2^H$$ Taking one example, if $p_1 = 0{,}69$ and p_2 has two possible outcomes: either $p_2 = 0{,}80$ or $p_2 = 0{,}60$ (all prices in NOK/kWh). From this we get that: $E(p_2^U) = 0{,}5 * 0{,}6 + 0{,}5 * 0{,}8.$ Which gives: $0{,}69 = p_1 < E(p_2^U) = 0{,}7$. and HPPs choose to produce everything in the second period.

With HPC

$$Max\,\{\, p_1 e_1 + \; E(p_2^U) e_2 \,\}$$ Where p_1, is known and we have the constraint: $e_1 + e_2 \leq W$
This gives us the Lagrange function: $$L = p_1 e_1 + \; E(p_2^U) e_2 - \lambda(\mathrm{e}_1 + \mathrm{e}_2 - \mathrm{W})$$
Working with the FOCs described above we get: $p_1 - \lambda \leq 0$ $E(p_2^U) - \lambda \leq 0$ $e_1 + e_2 = W$
In this case, the allocation of water depends on the relationship between the marginal revenue from the two periods, p_1 and $E(p_2^U)$, but now the price for period 2 is uncertain. Everything is as the case as for the uncertain case without the HPC so far. Following the same calculations, only that now the marginal revenue from the high-price outcome for period two is $(\mathrm{P} + (1 - tr)(p_2^H - P))$. This gives: $$E(p_2^U) = 0{,}5\, p_2^L + 0{,}5\, (\mathrm{P} + (1 - tr)(p_2^U - P))$$ Taking the same example where $p_1 = 0{,}69$ and p_2 has two possible outcomes: either $p_2 = 0{,}80$ or $p_2 = 0{,}60$ (all prices in NOK/kWh) we get that: $E(p_2^U) = 0{,}5 * 0{,}6 + 0{,}5 * (\mathrm{P} + (1 - tr)(0{,}8 - P))$ Setting in $tr = 0{,}23$ and $P = 0{,}7$ gives: $E(p_2^U) = \; 0{,}5 * 0{,}6 + 0{,}5 * \big(0{,}7 \; + (1 - 0{,}23)(0{,}8 - 0{,}7)\big)$ Which gives: $0{,}69 = p_1 > E(p_2^U) = 0{,}6885$. Hence, our allocated production change and the HPP will choose to produce everything in the first period.

In total, we have observed that under uncertainty, the allocation of production over time can be changed due to the high-price contribution. The setup shows the case where $p_1 < P$ – that is, the price in the first period is below the threshold for the HPC.

This section investigates how the allocation over time changes at the introduction of the high-price contribution, both under certain future prices and uncertainty. In this simplified model without a reservoir constraint the resulting outcomes are corner solutions, with all available water being allocated to one of the periods. In a real- life electricity market there will be reservoir constraints that can halt production allocation to be subject to corner solutions. By not allowing production to move freely between periods water values will be affected when the reservoir constraint is binding. There are also multiple other factors which are not considered in this analysis because of its simplifying assumptions.

5. Research Question and Hypothesis

This section describes the research questions (RQs) and the hypothesis of this thesis. As discussed earlier in the "Background" chapter electricity production in Norway is to a large extent adapted to demand, which makes it crucial to have enough production when demand is high. The flexibility of electricity production is possible by the large share of storable reservoir hydropower. If hydropower production is affected by new policies, this can reduce this flexibility in production. Because of the demand-driven power market electricity prices are driven by the demand, meaning that hours with high prices most often reflect high demand. The high-price contribution (HPC) affects exactly these high-price hours.

5.1. Basis for Research Question 1

When deciding when to produce, hydropower producers estimate the expected marginal revenue from producing one unit in a specific hour, and the water value of producing one unit of water later. The setup in the analysis of Aasgård et. al. (2017, s. 260) describes the objective behind allocation of water over time as a maximization problem. Maximizing quantity is the "revenues from selling power within the short-term horizon plus the value of water left in the reservoir at the end of the horizon". This can be translated to the simplified theoretical discussion above by assessing the short-term can translate to today (t=1) and the value of water at the end of this horizon to be the water value (λ).

It follows from the maximization problem that hydropower producers (HPPs) will choose to produce when the marginal revenue from selling power now is higher than the water value. The effect of the HPC on hourly allocation of hydropower can be separated into two effects resting on the same argument: the effect of the HPC on the marginal revenue today and the effect on water values. This section starts by explaining the marginal revenue effect, keeping the water value constant.

Before the HPC was introduced the marginal revenue was the price of electricity. After the introduction of the HPC, the hours with a price higher than 0,7 NOK has a marginal revenue of the price minus the tax. This means that the marginal revenue is lower in hours with a price over 0,7 NOK after the introduction of HPC, compared to before its implementation. Because of this reduced marginal revenue, we in the theory section showed that the HPC lowers the expected marginal revenue of producing under uncertainty. It is the hours where at least parts of the price probability range go over the 0,7 NOK threshold that are affected by this effect. In cases where the whole probability range is below 0,7 NOK, the tax will not affect the expected income from production.

As explained in the theory section, the HPC performs a monotonic transformation of the marginal revenue. This means that when there is no uncertainty the price is highest in the same hours before and after the introduction of the HPC. This indicates no changes to the allocation of water over time. However, HPPs do not know for certain what hours will have the highest price when making their bids – that is, there is an uncertainty of price which affects their production decision. As HPPs receive a penalty for not producing in line with their bids into the spot market, production plans are highly dependent on the production bids. In the bidding process, the spot price is still unknown but is revealed shortly after. This means that when making the bids, and in reality, deciding the production plan, there is still uncertainty about what the price will be. Production plans can also reflect participation in the intraday market, an effect that is not accounted for in this analysis.

Because of the uncertainty described above, for hours whose probable price-range goes over 0,7 NOK, the expected marginal revenue will be relatively less after HPC than before the HPC was introduced. Therefore, there is reason to believe that the same hours will be allocated less production, *when keeping the water-*

value constant. The theory-section displays the corner solution example of this. That for one plant all production will be allocated away from the period with a probable price-range going over 0,7 NOK.

Looking at historical data on average prices for the years 2021, 2022, and 2023, in Figure 5-1 below we see that the price is generally higher for some hours of the day than others. We observe that the trend in what times of the day with high average prices follow the trend of peak consumption in household and tertiary services. These peaks are mainly driven by daily energy consumption habits in private households, as stated in the background section. The figure shows that the price in load peak hours often surpass the 0,7 NOK threshold historically. It is reasonable to assume that HPPs consider such historical trends when making production decisions. Based on this and the arguments of high-price hours above, one can expect production during load-peak hours to be lower after the introduction of the HPC than before. However, as the HPC is set only as a share of the price exceeding 0,7 NOK, *we expect the effect to be rather small*.

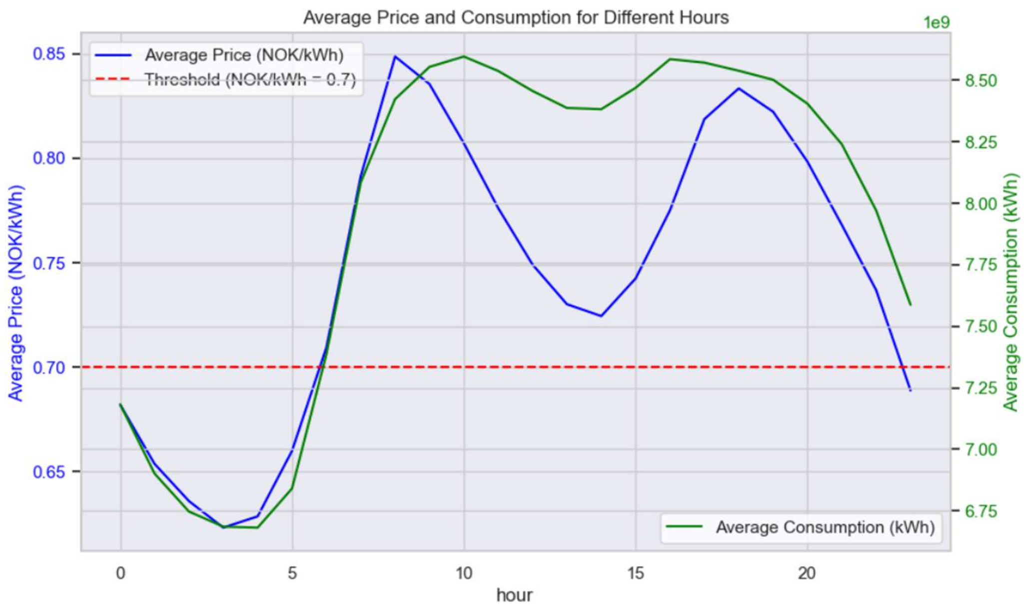


Figure 5-1. Average spot price and -consumption for different hours of the day, all bidding areas in Norway, 2021-2023. Source: Day-ahead spot price (NOK/kWh) (left axis) is described in section 6.3. Electricity consumption is the sum of the consumption in household and tertiary services (kWh) (right axis) is retrieved from Elhub (Elhub, retrieved 07.05.2024 c).

Now over to the second effect of the HPC on hourly allocation through the water value. The argument from above states that the HPC can alter allocation between hours of the day when price is uncertain, due to differences in marginal revenue. The price has also varied through the year historically, with lower prices in the summer and higher during winter. The Figure 5-2 shows the average price for hours in the day, for each season. The figure represents data from 2021, 2022 and 2023. We observe that even during the summer the average price is above 0,7 NOK for the peak hours. For the winter almost all hours have an average price above 0,7 NOK. The graph shows us that even though price levels vary between seasons there is still a within-day variation on average. We do note however that the mid-day descend does not seem to be as large for the winter season, for which also the nigh drop seems to be even more distinct than for other seasons.

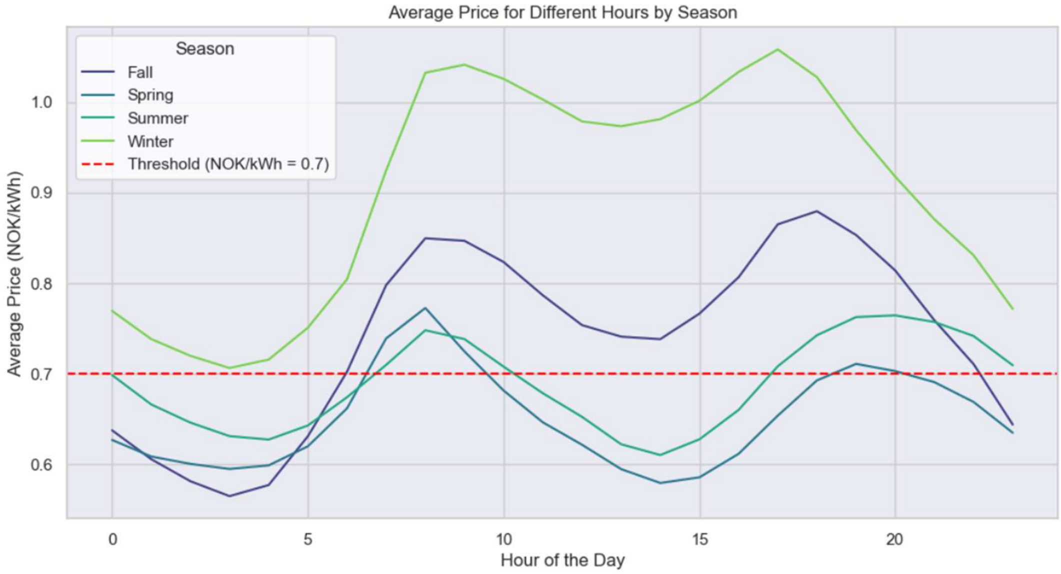


Figure 5-2. Average spot price for different hours of the day, for different seasons, all bidding areas, Norway, 2021-2023. Source: Day-ahead spot price (NOK/kWh) is described in section 6.3.

The potential change in marginal revenue of production due to the HPC affect both the marginal revenue of producing the current hour and the water value which it compares against. This can lead to other adjustments in addition to the first effect. The two main factors for the water value are the expected marginal revenue in future periods and the size of the reservoir for each HPP. The reservoir size is seen as constant in this analysis, but the expected marginal revenue on the other hand is affected by the HPC with the same logic as explained above and in the theory section.

As shown above, winter months have historically a higher average price. These level differences reflect changes in demand, mainly driven by temperature changes. Lower temperatures lead to more building heating, not the daily habits as in the case of daily peaks. Water values are often higher during the fall, due to the approaching winter season, which most likely have higher average price. This incentives HPPs to save water for future periods. However, as more of the hours during the winter season are subject to the HPC, the tax will also be present in a larger share of the hours. Hence, the HPC decreases the expected marginal revenue for the winter season. This reduces water value during the autumn creating lower incentives to save for the winter season, resulting in higher autumn production. Therefore, the HPC can shift the allocation of production between seasons in addition to the within-day effect. As prices still vary between hours of the day a change to the water value described above can lead to higher/lower production in marginal hours, thereby affecting allocation of production for hours in the day in the long run.

Water values are based on forecasts of future prices. These forecasts are often highly uncertain and based on some aggregate time-level, and granularity on the hourly level is unlikely. From this, it is a reasonable assumption that the water value is the same for all hours of the day. Changes to the water value between seasons affect the level for the whole day, but this seasonal effect due to temperature changes does not eliminate the hourly differences driven by daily habits.

5.2. Basis for Research Question 2

Also, the second research question is based on the same argument as above. Figure 5-3 shows the average prices for hours of the day across different bidding areas in the period 2021-2023. From the figure the average prices are below the 0,7NOK/kWh threshold for all hours of the day for the bidding areas NO3 and NO4, while it is above for NO1, NO2 and NO5. There is a clear distinction in the average price for different hours over the bidding areas. The HPC is connected to high prices. When prices differ between bidding areas it is reasonable to hypothesis that also the effect of the HPC on hourly allocation of production stated for the first research question will differ across the same areas.

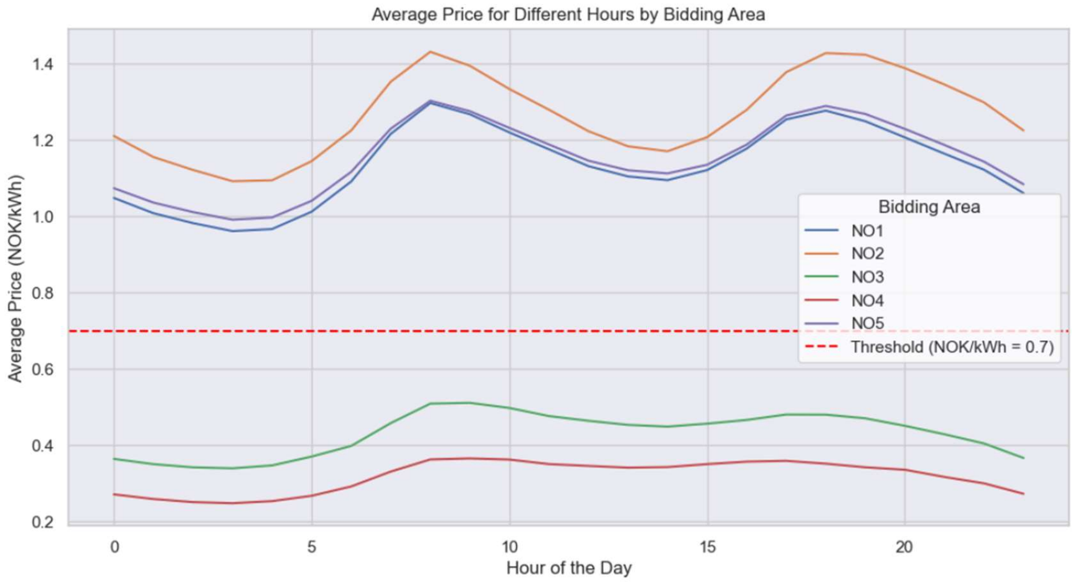


Figure 5-3. Average spot prices for hours of the day across different bidding areas, 2021-2023. Source: Day-ahead spot price (NOK/kWh) is described in section 6.3.

5.3. Research Questions

Based on the arguments above we want to answer the following research questions (RQs):

RQ1. How does the Norwegian high price contribution affect the allocation of reservoir hydropower production throughout the day?

RQ2. Is the effect from RQ1 dependent on the general price level in different bidding areas?

The RQs can be answered using econometric methods estimating production before and after the introduction of the HPC. If the factors relevant for deciding the production of hydropower are included in the model we have controlled for all relevant variables, in theory leaving only the effect of the high-price contribution left. The RQs could also be answered using a dynamic modelling approach, but such an investigation would be outside the scope of this thesis.

It is not certain which of the effects explained above (marginal revenue or water value) that dominates the total effect on hourly load of the HPC. This thesis might not be able to distinguish where the effect on shifts in production between hours comes from empirically. However, it is reasonable to assume the effect through the water values is the strongest as there is greater uncertainty of future prices than of tomorrows. The goal of the thesis is the total average effect on hourly differences in production levels, not the singular effects of the policy on water values and marginal revenue separately.

Also, for both effects on hydropower production due to the HPC it can be the case that changes to the production leads to different market prices. As foreign power production is not subject to the HPC a change in the Norwegian market price might increase trade. Increased trade can again increase the price, which again increases national production. In total the presence of trade can distinguish the effect on prices of the HPC, which again can reduce the effects on production over time. This will not be accounted for in this analysis.

6. Data sources

The section explains how the thesis collects information on the variables included in the analysis. The thesis takes an empirical approach, using data from several sources to answer the research questions. Data on planned hydropower production, maximum installed capacity and day-ahead electricity prices is retrieved from the Norwegian Energy Regulatory Authority (RME), futures electricity prices from Macrobond and Euroepan gas- and carbon prices from Montel. Also, weather data on reservoir filling and temperature data is retrieved from the Norwegian Water Resources and Energy Directorate (NVE) and the Norwegian Meteorological Institute (MET) respectively. All data is for the Norway market unless otherwise specified. For each variable descriptive statistics and explanations on how data is treated is provided

6.1. Production Plans

The thesis retrieves data on production plans per hour per station group from the Norwegian Energy Regulatory Authority (RME). The data is obtained for the full years of 2021, 2022 and 2023.

Choice of Production Variable

Information on hydropower production can be obtained both in the form of planned production and the actual measured production, and choosing the right variable is an important for the analysis. As opposed to data on actual production, production plans do not include changes in production due to participation in the reserve/balance markets (Statnett, Retrieved 07.05.2024 b) for electricity, or unexpected weather events or grid fallouts. Such events can result in changes in the actual production that are not easily accounted for in the analysis, resulting in more systematic noise in the data, which can make it more difficult to obtain valid estimates. Production plans do not entail this noise, and therefore provides an advantage when analysing how the hydropower plants alter their optimal allocation of production over time.

Station groups are required to report on *net* planned production, meaning that the data includes information on the consumption of electricity for pumped storage, resulting in negative planned production. The reason for this is that the net planned production includes the additional consumption meters from pumped storage while actual production measures only production. This is one possible downside of using production plans instead of actual production. However, as shown in the background section, pumped storage is small relative to actual production. Also, production plans are seen as more sensitive information than actual production and can therefore be more difficult to obtain information on. In total, data on planned production is seen as a more beneficial variable of input to the analysis than actual production.

Origins of Production Plans

To gain access to trade in the wholesale market, operators are required to have a direct balance agreement with Statnett, the system operator (SO). Market participants can either balance on their own behalf or have an agreement with a balance responsible party[10] (Norwegian: balanseanvarlig) to settle their imbalances for them (Elhub, Retrieved 07.05.2024 b).

Production plans, along with available reserves and system data, are reported by the balance responsible parties to the SO by 16:00 each day for the next 24 hours (Statnett, 2023). Changes to the production plan and system data must be reported continuously as they occur, and generally no later than 45 minutes before the operating hour. This information is used by the SO to be able to handle bottlenecks in the grid.

[10] Statnett is currently working on splitting the role of the balance responsible into two separate roles, but this change is not relevant for our period in question.

Production plans are required to be in line with the bids to the spot and intraday markets and the SO follows up major and/or repeated deviations from the production plan (Regulation on the system responsibility in the power system, 2002, s. § 8). This means that the production plans are decided by the bids placed in the spot and intraday market.

Production plans are recorded per station group, a collection of several production plants. The station group is decided by the system operator in agreement with the relevant operator. The division into station groups is first based on already existing station groups. Second, a station group must be located within one fixed area (Norwegian: fastområder) but can include production plants in several bidding areas. Statnett have defined 8 fixed areas that are used for consumption forecasts which should remain unchanged to ensure comparability over time (Statnett, 2018). For the data used, all station groups have reported production in only one bidding area. Lastly, production in the same station group generally has the same production type. Usually, only one actor owns all the plants in one station group, but there exist station groups (and plants) with several owners. One power producer can have several station groups. Also, one station group is normally (but not always) located along one riverbed, but there might be several station groups along the same riverbed, and there are rules for how station groups along one riverbed must communicate to prevent flooding. Because plants within one station group is often along one riverbed, data on this aggregation level compared to singular plans can reduce the effect of a hydropower producer's optimization being altered among generators along one riverbed.

In addition to the reporting per station groups, all singular power stations with a total output (Norwegian: samlet ytelse) $\geq 50\ MVA$ rated power (Norwegian: merkeeffekt) must report production plans and system data for each unit (Norwegian: aggregat). The data is submitted and updated with the same procedure as for data at station group level. Information on the collection of data from production plans can be found at the pages of Statnett (Retrieved 07.05.2024 d)

Process of Attaining Data

Both data on the production of electricity per plant and station group data on production plans (and total installed capacity) is regulated under the authority of the Public Administration Act (Norwegian: forvaltningsloven) (1970, p. §13). This is because it is company sensitive information that can provide detailed information about the producing unit that can be used for harming business' activity. This has made it difficult to obtain the appropriate data for use in this thesis.

The first alternative to attaining data would be to retain data from public sources. Elhub (retrieved 07.05.2024 c), NVE (Retrieved 07.04.2024 i) and Statnett (Retrieved 07.05.2024 c) all publish data on production of hydropower. Also, the transparency regulation (Norwegian: transparensforordningen) requires the reporting and publication of actual produced power (n: effect) for generation units with 100 MW or more installed production capacity and is published by the European Network of Transmission System Operators for Electricity (ENTSO-E) (Norwegian Government, 2017) and (RME, Retrieved 07.05.2024 b). These public sources have a too high time resolution, have data at a level of aggregation giving few observations, as it is not possible to distinguish only regulated hydropower from pumped storage hydropower. Together, this makes it unlikely that it is possible to draw conclusions on the research questions of statistical significance from these sources. Another alternative could be to contact hydropower producers directly and ask for the data of their plants. However, this would require a large coordination process – a work that is deemed to time intensive for the scope of a thesis.

In October 2023, a coordination process started to find at what granularity production data is available from different institutions. Contact was made with both Elhub, RME and Statistics Norway (SSB). SSB stores electricity data on monthly basis only, which is not sufficient to analyse the research questions of the thesis.

Elhub and RME both have data on actual production of hydropower per hour. RME in addition has data on hourly production plans. Of RME and Elhub, the preference for data collaboration was on RME as it was possible to obtain information on planned production and the time-horizon for attaining the data was perceived as shorter. Also, Elhub is restricted by the EU General Data Protection Regulation (GDPR) to store the data for no more than three years, possibly making it a challenge for data analysis.

Specifications of the data

Ideally, data would be available per plant to match production data with other relevant confounding variables about business characteristics. However, a necessary condition for attaining the data was to aggregate the production plans into groups with information such that each plant is not recognizable. Under advice of RME, the variable of aggregation is station groups as this is the aggregation for which production plans are reported. Data quality might be an issue when aggregating the data from the granular level. Testing the quality of the data for unrealistic values is only possible with access to the metadata of each metering point. That is, the approximately the range of the production level that is realistic for one production plant is known. However, for data on station groups, the range of realistic values becomes much wider as it aggregates over several plants. Hence, it is more difficult to assess what observations that give unrealistic values. However, the data quality is assessed by RME as part of their regulatory tasks, providing some quality assurance.

Some metadata is available for each station group: bidding area and total installed capacity. The data on the station group is anonymised, with a randomly assigned station group ID assigned to each station group. This means that further information on geographical location or the number of plants in each station group is not available, providing difficulty matching the data with variables from other sources. Also, with respect to privacy concerns, station groups with total installed capacity lower than 50 MW are excluded from the dataset.

Before aggregation, RME has ensured that that the plants in each station groups entails some characteristics. First, for each station group it is ensured that only power production defined as reservoir power is included. However, the definition of reservoir power might not always be accurate, as it can be difficult to accurately distinguish between reservoir and run-of-river hydropower. E.g. very small reservoir might be defined as reservoir power, but in practice it can function like unregulated run-of-river hydropower as the storing capacity is small. This is not accounted for in the analysis.

Second, only station groups where all plants with rated power output (Norwegian: påstemplet merkeytelse) of 10,000 kVA or more is included in the dataset. That is, for the included station groups the high-price contribution (HPC) was introduced for all plants on 28 September 2022 as explained in section 2.3. As the high-price contribution is introduced for all units at the same time as a control group for the analysis is not available. One possible solution to this difficulty, would be to find similar plants above/below to the threshold of 10,000 kVA and analyse differences in adaption. This is possible as the HPC was not introduced for power plants below 10,000 kVA and higher than at least 1 MW until January 2023. This has not been possible in this thesis because of the aggregation.

Lastly, the number of hydropower plants may change over time, reflecting overall profitability in the industry and general development in the electricity market. Higher electricity prices over time can result in larger investments in hydropower, leading to the establishment of new producers. This can again lead to a higher total production of hydropower. The opposite is true for changes negatively affecting the profitability of the industry, such as taxes on the production of hydropower. The effect of changed profitability over time is not the focus of this thesis. This makes it important to exclude additional and shut-down producers from the analysis. If not, the analysis would also catch the change in overall hydropower production due to new (or retired) producers. The dataset used in the thesis shows only the BRPs and station groups that have not had changes in their organisation in the period 2021-01-01 to 2023-12-31. Information on new power production can be found at an aggregate level at RME's webpages (RME, Retrieved 07.05.2024 a). Also, station groups with changes in production capacity above 10 MW to at least one its generators are excluded from the analysis. This means that when the definition of the station group is changed to include new plants, or remove old ones, these station groups are excluded from the data set. However, small upgrades to existing plants might be included in the data set.

Data Quality Issues

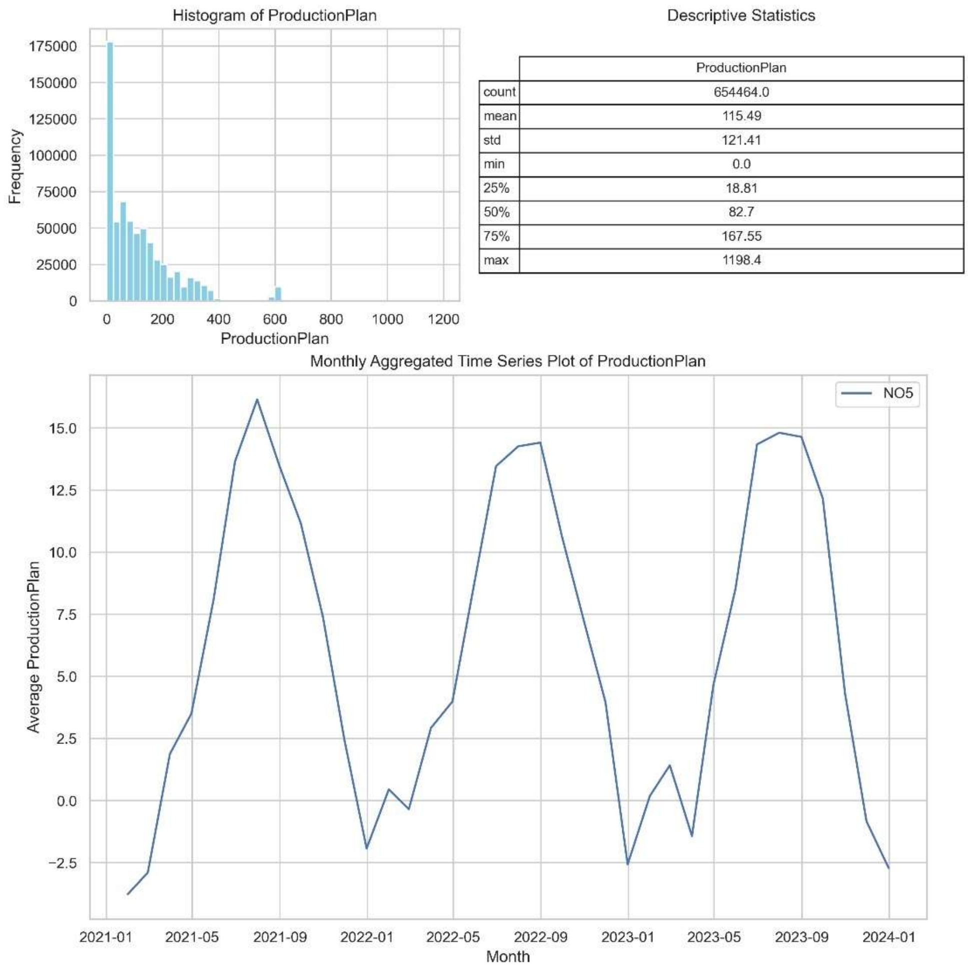
For all three datasets, the dates of January 25., 26., 28. and 30. 2022 are no available from RMEs website. The dataset on production plan also misses one hour for every winter backward time-zone shift. Also, several station groups have the same station group number in different bidding areas. RME does not have exact answers for what the reason for the overlap is. The issue with unique identifiers is solved by creating a new identifier containing the station group number and the bidding area.

Variable Statistics

Figure 6-1 bellow shows summary statistics for production plans (measurement in MW): a histogram of the production plans (top left), a table summarizing descriptive statistics of the variable (top right) and a plot of the monthly average of production plans over time (bottom).

Looking at the top left panel notice a high share of zero values. This is what is called corner solution responses, a concept described in larger detail in the methodology chapter. Also, observe that for some of the observations, the production plans are negative. This happens because production plans are reported on net planned production. In other words, consumption from pumped storage is higher than the total production from the station groups. In some cases, one might see that station groups are producing at the same time as consuming for pumped storage, but the probability that pumped storage is profitable at the same time as it is optimal to produce a lot is low. Because of this, hours with negative production plans are removed in our analysis.

In the econometric model, production plans are used as the dependent variable without taking any transformation (log, squared). The reasons for this lie mainly in that it increases the interpretation of the estimates obtained, a large advantage when communicating findings. Also, in the python packages available for estimation, it was not possible to set the censoring level at another than zero.



	ProductionPlan
count	654464.0
mean	115.49
std	121.41
min	0.0
25%	18.81
50%	82.7
75%	167.55
max	1198.4

Figure 6-1. Summary statistics of the production plan variable. Top left: histogram. Top right: descriptive statistics. Bottom: development over time, monthly average, measurement in MW.

6.2. Maximum Installed Capacity

Maximum installed capacity (MaxEffect for short) reflects the technical maximum production capacity at one station group. That is, it affects only the upper bound, but not the lower band of the production plans. Intuitively, the MaxEffect tells us something about the size of the station group. As this is the only information available on the station group outside of the bidding area it lies within, this is an important variable to include to reduce unobserved effects of each station group.

Information of maximum installed capacity (measured in MW) is obtained from RME along with the data on production plans. RME report that the variable values are uncertain and might be prone to measurement error. If these errors are systematic this might induce bias to our regression. However, if the measurement error is random/not systematic this measurement error does not entail bias, only increase our variance.. Of privacy concerns summary statistics of the MaxEffect is not included in the thesis. However, it has been checked that the variable is relatively constant through the entire period of question. In the econometric model MaxEffect are used as an independent variable without taking any transformation (log, squared).

6.3. Day-Ahead Electricity Prices

As stated in the chapter on the conceptual framework, the hydropower producers evaluate the relationship between the water value and the expected marginal revenue when making the production decision. As the most important factor behind the expected marginal revenue, expected electricity prices are important to control for in any analysis of hydropower production. The observed electricity prices can work as a proxy for expected electricity prices. As there exists several markets for electricity, there are different options for what electricity price to use in the analysis. The spot market is the market where most of the volume of electricity is traded and it's the main base the high-price contribution takes. Hence, this thesis utilises the spot-prices. The hourly spot prices are traded at the NordPool marketplace, and they are known a little after noon the day before the operating hour. The marketplace is open all days of the year.

Production plans must be in line with commitments from participation in the spot and intraday markets. The spot price is not known when giving the bids to the spot market, but the equilibrium price is decisive for the volume producers are committed to deliver. That is, the equilibrium price has a direct effect on what bids are "activated". It is the activated bids in the spot and intraday market that are reflected in the production plans, our variable of analysis. Hence, the spot price of that hour of one day have a direct effect on the production plan of the same day, leading to simultaneous causality which is explained in more detail in the section on "Latent Explanatory Variables". Because of this issue, the electricity price which is included in the model is lagged by 24 hours for each production plan observation.

Data on the hourly spot price of electricity per bidding area in Norway is retrieved from RME, who have attained the data from ENTSO-E, a publicly open database. The unit of price is originally given in EUR/MWh but is converted to kWh and to the local currency, NOK, using the same daily exchange rate which is used by Nord Pool in conversions. The price is used in EUR, not NOK, in the statistical analysis to maintain consistency between different price currencies, but NOK values are utilised for descriptive statistics and for creating other variables as the high-price contribution is set based on NOK prices. Time is given in UTC+1 during wintertime and UTC+2 in summertime. In other words, it reflects local time in Norway.

Figure 6-2 below shows summary statistics for current electricity price (measured in NOK/kWh): a histogram of the production plans (top left), a table summarizing descriptive statistics of the variable (top right) and a plot of the monthly average of the variable over time for different bidding areas (bottom). For some observations in the dataset, negative electricity prices are obtained. These amount to about 2% of the observations. As removing these do not highly affect our regression results, the observations are kept in the dataset. However, one implication of this is that a log-transform of this variable cannot be made in the estimation.

From the top right panel notice that for half of the observations, prices are less than 0,49 NOK/kWh, with 75% being bellow 1 NOK/kWh. However, at least one extreme observation of 8,22 NOK/kWh is observed. From the bottom panel observe the earlier mentioned trend of rising prices from the fall of 2021. First notice that electricity prices look overlapping for NO1 and NO5. Monthly prices in these two bidding areas are extremely similar for the period in question, but they are not exactly the same (for most periods). Monthly values of NO1 and NO5 are checked against NoordPools public data (NordPool, Retrieved 07.05.2024). Also from the bottom panel, notice that NO3 and NO4 did not experience as extreme price increases as the other bidding areas during the period.

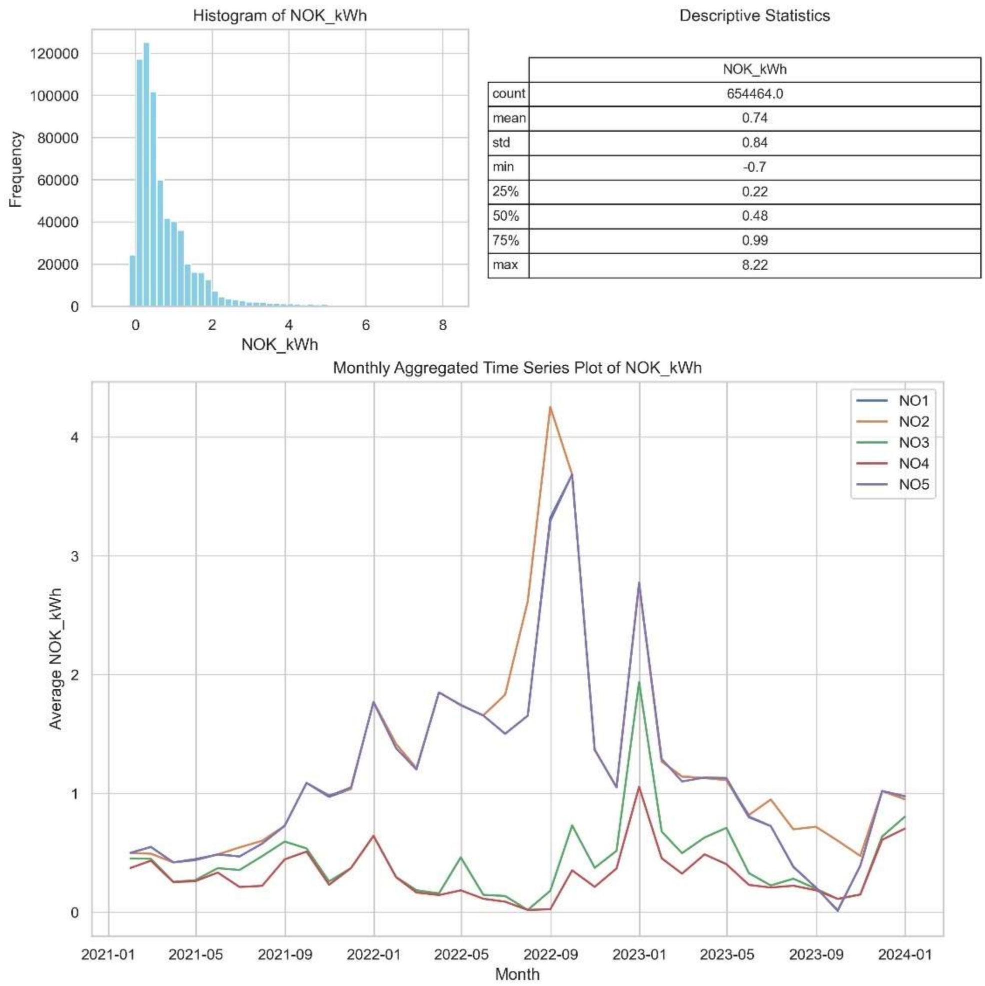


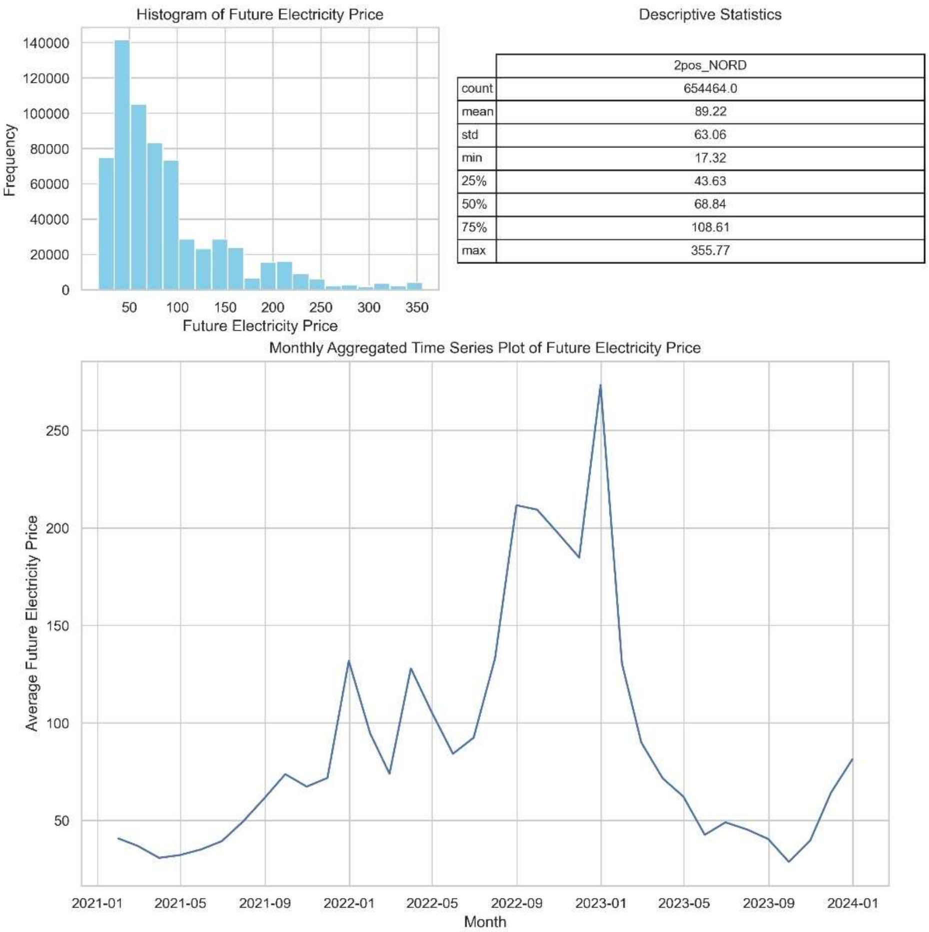
Figure 6-2. Summary statistics of the spot price variable. Top left: histogram. Top right: descriptive statistics. Bottom: development over time for each bidding area, monthly average, measured in NOK/kWh.

6.4. Futures Electricity Prices

As discussed in the section on the Research Question and Hypothesis the water value depends on expectations of future revenues from production of hydropower. Future revenues are highly dependent on the future price of electricity. Using the actual future price of electricity (futures prices) is one way of reflecting the future prices, but this would require HPPs price expectations to be very precise. A better indicator of the expected price in the future is the futures prices, which to larger degree reflect the market expectations for the electricity price in the future. When assessing the price in the future electricity markets, it is often divided between futures and forward markets. Birkedal & Bolkesjø (2016) states that many stakeholders in electricity markets treat futures and forward markets as an unbiased estimator for futures prices, given that the markets are liquid. Futures prices refer to the agreed-upon prices for the delivery of electricity on a specified future date. These prices are determined on futures markets, where buyers and sellers enter contracts to either purchase or sell electricity at a future point in time. Forward contracts on the other hand are traded over the counter (OTC), meaning that the contracts are negotiated and traded directly between two parties. This setup entails greater uncertainty for the public on the terms of the trade compared to futures markets. Because of this uncertainty, this thesis utilizes futures electricity markets.

Futures markets contracts can be tied to spot prices (down on each bidding area) or to system prices (synchronous grid areas). Futures markets for individual bidding areas have historically been assessed to have low liquidity, we use a futures price dependent on the Nordic system price in this thesis. Specifically, we obtain data on the ICE Nordic Power Financial Base Futures from Macrobond. The price is for 2nd positions, that is contracts for delivered electricity two months forward in time. The price is delivered in daily closing price for EUR/MWh. The marketplace is closed during weekends and public holidays. Each production plan is matched with the last available futures price. However, as the marketplace does not close until 6pm (Intercontinental Exchange, Retrieved 07.04.2024 b) the futures prices is available for spot market bidding the day after closing and reflected for production plans for operating hours the day after that again. Hence the futures price is lagged by two days in our dataset and log transformed for the analysis.

Figure 6-3 below shows summary statistics for future electricity price (measured in EUR/MWh): a histogram of the production plans (top left), a table summarizing descriptive statistics of the variable (top right) and a plot of the monthly average of the variable over time (bottom). Observe that the development of future price over time follows much of the same trends as those seen in the current electricity price as shown above. However, the future electricity does not see the same September-maximum that we saw in the southern bidding areas in Norway. Instead, the max for the future price is in January 2023. Also notice no negative values and a somewhat flatter curve than the distribution of Norwegian electricity prices.



	2pos_NORD
count	654464.0
mean	89.22
std	63.06
min	17.32
25%	43.63
50%	68.84
75%	108.61
max	355.77

Figure 6-3. Summary statistics of the future system price variable. Top left: histogram. Top right: descriptive statistics. Bottom: development over time, monthly average, measured in EUR/MWh.

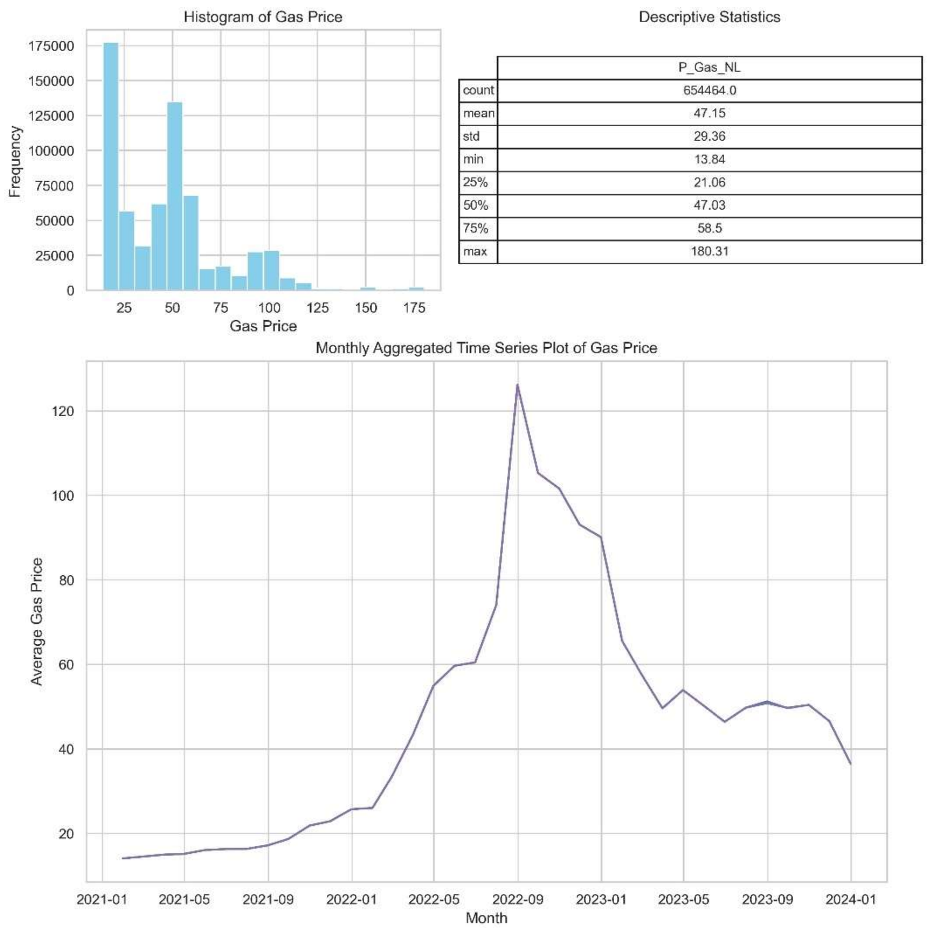
6.5. Futures European Gas Price

In a closed economy, the electricity price in Norway would be decided by national supply and demand. However, our transmission network is closely connected with both other Nordic countries, and Norway have an enormous transmission capacity abroad. Because of this, the energy situation in our trading economies also affect Norwegian prices. As a result, the analysis must control for variables important for the European electricity prices. Also, gas makes up a large part of the European electricity production and the gas price is likely to affect the European and hence the Norwegian electricity prices. Because of the above arguments the European gas price is included as a variable in this analysis.

Daily gas price data is also obtained from Montel on the ICE Endex TTF natural gas price (Intercontinental Excange, Retrieved 07.05.2024 a). TTF stands for the Dutch marketplace Title Transfer Facility, one of the largest trading hubs for natural gas in Europe. The price often serves as a benchmark for the European natural gas market (European Comission, 2022). Specifically, the TFM closing price in EUR/MWh is obtained. Following the same argument from the futures prices the gas price is lagged by two days in our dataset and log transformed for the analysis.

On the TFM market multiple contract times are available, from month, quarter, season, and year. This makes the TFM a futures price for gas. One might also expect European gas prices to affect Norwegian electricity prices today, not just the water value in the future. However, the futures gas price and the current gas price is probably highly correlated. Therefore, this thesis does not collect data on more current gas prices[11]. For the remains of the text the European futures gas price is referred to as gas price.

Figure 6-4 below shows summary statistics for gas price (measured in EUR/MW): a histogram of the production plans (top left), a table summarizing descriptive statistics of the variable (top right) and a plot of the monthly average of the variable over time (bottom). Observe that the development of future price over time follows much of the same trends as those seen in the current electricity price, although the development for 2023 does not resemble the current price as closely as the future electricity price. Also, notice no negative values.



	P_Gas_NL
count	654464.0
mean	47.15
std	29.36
min	13.84
25%	21.06
50%	47.03
75%	58.5
max	180.31

Figure 6-4. Summary statistics of the gas price variable. Top left: histogram. Top right: descriptive statistics. Bottom: development over time, monthly average, 2021-2024, measured in EUR.

6.6. European Carbon Price

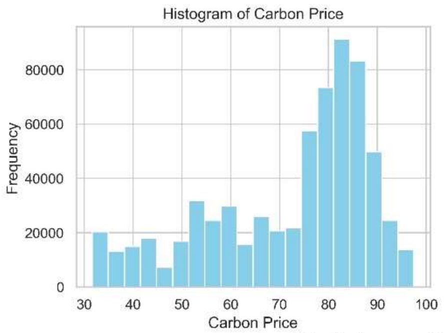
As stated in the section above, the Norwegian and European electricity prices are highly connected and we must control for variables in the European electricity price when assessing Norwegian production of

[11] An appropriate day ahead gas price for current prices could be the TTF TFE day-ahead (DA).

electricity, which highly follows the price. Fossil energy types stands for more of the electricity generation in Europe than it does in Norway. The price of generating electricity from fossil fuels is highly affected by the European Emissions Trading System (EU ETS) as stated in the section on “Climate Policy”. Because of this argument the European carbon price is included as a variable in our analysis.

Data on daily carbon prices of the European Energy Exchange (EEX) EUSP European Carbon Spot is obtained from Montel. The daily closing price is given in EUR/t. Following the same argument from the futures prices the carbon price is lagged by two days in our dataset and log transformed for the analysis.

Figure 6-5 below shows summary statistics for carbon price (measured in EUR/t): a histogram of the production plans (top left), a table summarizing descriptive statistics of the variable (top right) and a plot of the monthly average of the variable over time (bottom). Unlike the Nordic futures elecitricity price and the European gas price the carbon price does not follow the same time-trend. The reason for this can be many, but the price is closely connected to the size of the quota for the EU ETS. Neither here any negative prices are seen, and the histogram’s distribution is more skewed to the right.



Descriptive Statistics

	P_Carbon
count	654464.0
mean	72.23
std	16.51
min	31.64
25%	59.45
50%	78.3
75%	84.53
max	97.5

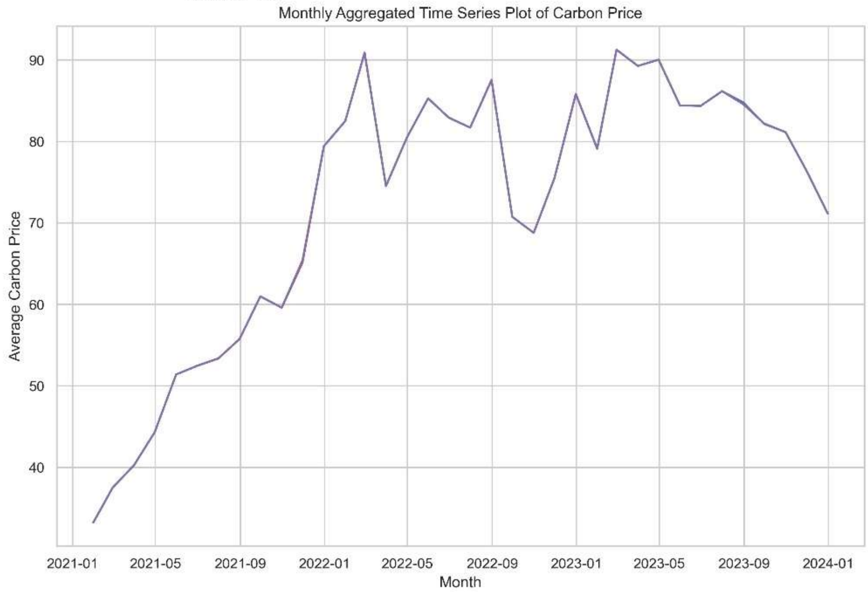


Figure 6-5. Summary statistics of the carbon price variable. Top left: histogram. Top right: descriptive statistics. Bottom: development over time, monthly average, 2021-2024, measured in EUR/t.

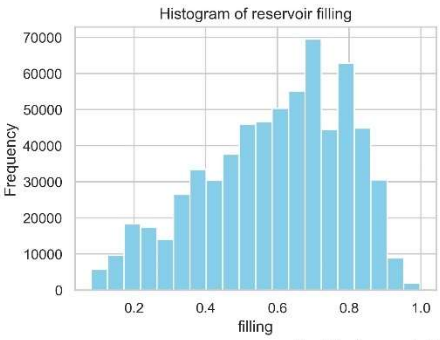
6.7. Reservoir Filling

A crucial factor for hydropower production is that there is available water to produce, which is reflected in the hydrological balance. Weather data is important to provide information on the uncertainty of supply and demand. A crucial factor for hydropower plants to consider when determining the water value is the reservoir filling. To represent the hydrological data the thesis makes use of reservoir filling.

NVE provides information on hydrological data per week, per bidding area, in the form of reservoir filling (NVE, Retrieved 07.04.02024 e) and hydrological balance (NVE, Retrieved 07.05.2024 d). These variables are not available at lower time resolution because of the measuring methodology. Also, as observations on station groups are anonymized data on such granularity is not possible to match with station groups. As mentioned in the handbook for the reservoir statistics the reservoir filling value are observed every week Sunday evenings 24:00 (NVE, 2019). This is the date of the weekly hydropower data. However, measurements are made public Wednesday at 13:00, meaning that the information is available for Thursdays bidding, and reflected in production plans on Friday the earliest. Because of this we will in the analysis lag the observation of one week's reservoir filling with five days.

Figure 6-6 below shows summary statistics for reservoir filling (measured in percentage, %): a histogram of the production plans (top left), a table summarizing descriptive statistics of the variable (top right) and a plot of the monthly average of the variable over time for different bidding areas (bottom). From the top right panel, see that for some observations the reservoir filling is above 1, that is, the reservoirs in the bidding area are filled more than 100%. This might indicate that there is overflow in several reservoirs, but as there are regulations against wasting water, which is perceived as little plausible to be the case for the entire bidding area as a whole. From this it can be concluded that these observations might be the case of measurement error and removed from the dataset used for analysis.

From the bottom panel observe a clear seasonal pattern in the reservoir filling, like mentioned in the background chapter. Do note however, that the seasonal pattern seems to vary between the bidding areas, e.g. the filling level for NO1 and NO5 seems to be lower at the minimum value compared NO2 and NO4 for all three years. The lowest reservoir filling was 8% for NO1 in May 2022.



Descriptive Statistics

	filling
count	654464.0
mean	0.59
std	0.2
min	0.08
25%	0.45
50%	0.63
75%	0.75
max	1.0

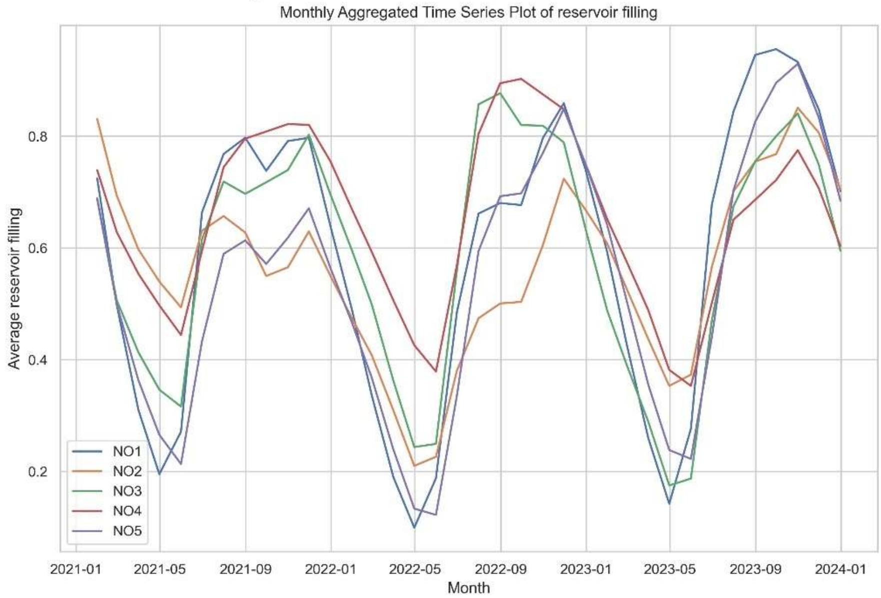


Figure 6-6. Summary statistics of the reservoir filling variable. Top left: histogram. Top right: descriptive statistics. Bottom: development over time for each bidding area, monthly average, measured in %.

6.8. Temperature

Temperature is the main driving factor the demand for electricity, especially during the winter months. Hence, it is a crucial factor to include to determine the variation in demand which affect the expected current electricity price. For this thesis average hourly air temperature in degrees Celsius is retrieved from the Norwegian Meteorological Institute (MET), FROST API. The temperature is retrieved in degrees Celsius in time UTC+1 (wintertime)/UTC+2 (summertime). Data is collected for all weather stations with available observations for the time-period (2021, 2022 and 2023) for one municipality in each bidding area. The municipalities chosen are:

- NO1 – Eastern Norway – Oslo
- NO2 – Southern Norway – Kristiansand
- NO3 – Central Norway – Trondheim
- NO4 – Northern Norway – Tromsø
- NO5 – West Norway – Bergen

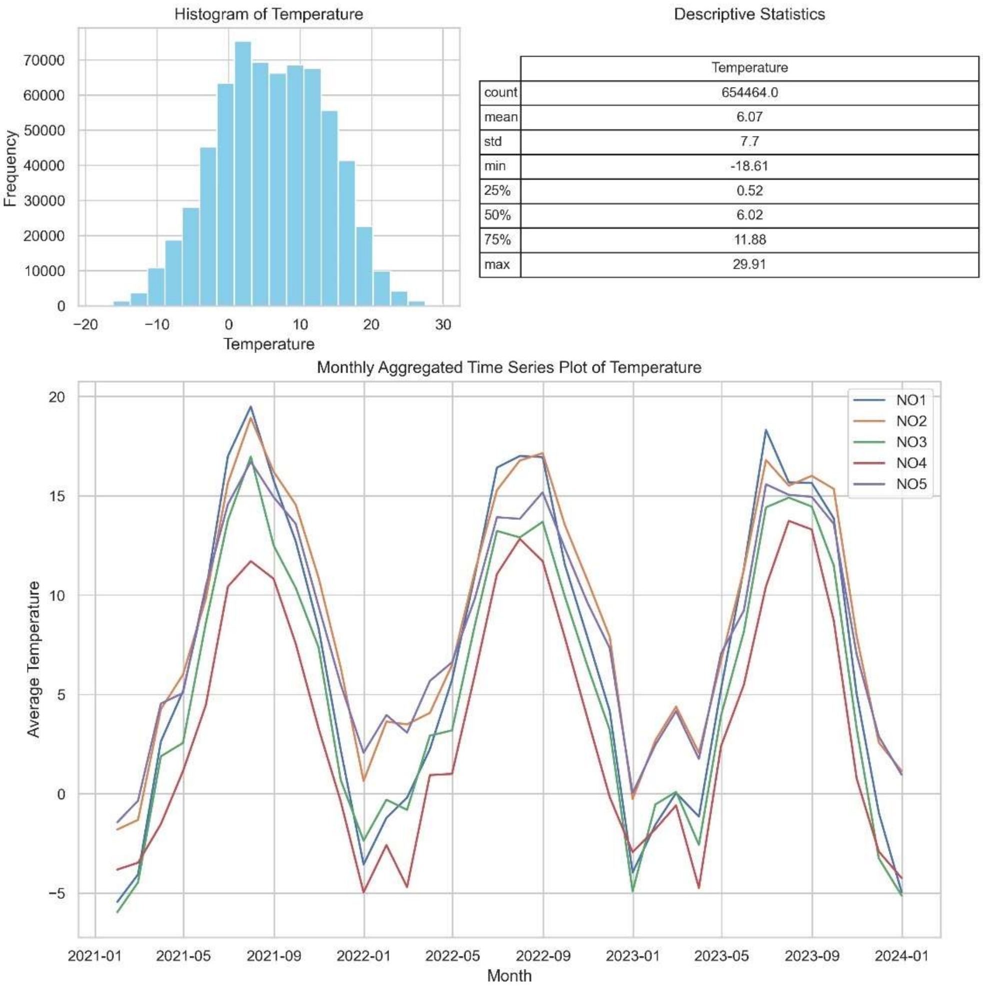
The municipalities were chosen after discussion with NVE, and what they make public in their own reports. One might argue that including Stavanger as a city for NO2 and Alta for NO4 would have been an even better approximation. One might also imagine that adjusting for the population in the different cities may be beneficial if one were to include multiple cities within one bidding area.

Other approaches were tried to obtain temperature data. To get a better picture on the temperature in the entire bidding area it was originally tried to obtain estimates for all weather station within the entire bidding area, represented by a polygon. A polygon for the price area is retrieved from the database Temakart from NVE (Retrieved 07.05.2024 g), then used to retrieve an average temperature over all weather stations in the area within the polygon. Data on this is available both through the NVE API (Retrieved 07.05.2024 b) and the MET FROST API. However, the approach did not succeed because of difficulties with the polygon becoming too large for the APIs to handle.

Temperature is known instantly, and often well forecasted ahead of time. That means the temperature for the given hour is used, not its lagged value. However, the effect of temperature on the electricity network is not a simple function. For cold temperatures, households will turn up heating making electricity consumption high (which again reflects in price). On the other side consumption for cooling during summer months are almost no households but driven by businesses (Ericson & Halvorsen, 2008).

Figure 6-7 below shows summary statistics for temperature (measured in degrees Celsius): a histogram of the production plans (top left), a table summarizing descriptive statistics of the variable (top right) and a plot of the monthly average of the variable over time for different bidding areas (bottom). Also here, see a clear seasonal pattern, with NO4 showing the lowest monthly average for most months which is unsurprising as it is also the northernmost bidding area.

Low temperatures are connected to higher electricity use for household heating, which is driving much of electricity consumption during winter months. However, at higher temperatures household heating is a small share of the consumption mix heating tends to be excessive during warm months. In these months the consumption mix is to larger degree other consumption groups, which may have increased consumption for higher temperatures dues to a need for cooling systems. This may indicate that temperatures should have another functional form than a linear. This thesis has tested squared and log-transformed versions of the temperature to try to catch this effect but have decided to not include it in the final model out of concern for out-of-sample performance. When keeping the linear functional form of temperatures, it can be expected the effect of cold months to be dominating. That is, in total it can be expected higher temperatures to have a negative effect on production plans.



	Temperature
count	654464.0
mean	6.07
std	7.7
min	-18.61
25%	0.52
50%	6.02
75%	11.88
max	29.91

Figure 6-7. Summary statistics of the temperature variable. Top left: histogram. Top right: descriptive statistics. Bottom: development over time for each bidding area, monthly average, 2021-2024, measured in degrees Celsius.

6.9. Time- and Unit Specification

Data on production plan are obtained per hour. The data is retrieved UTC but converted to local time (CET/CEST). For simplicity all other data sources are made to match this setup. However little of the data for merging is at such a granular time specification. Where differing, the time measurement of data other sources (gas, carbon and futures electricity price, reservoir filling) is adjusted to match the time measurement of the production data. That is, all data sources is set with a time aggregation higher than that of the production data as a constant for all the relevant observations.

The production plan data is collected per station groups, but all observations are anonymous, making it difficult to merge with other sources. Hence, for data sources where the entity is at more aggregate level (per bidding area or for the entire country) the observation is set as a constant for all station groups.

6.10. Specifics of the High-Price Contribution

The HPC was introduced the same day as it was announced, not giving producers a chance to prepare for the new policy. This means that for a period, it is likely that producers had not yet adjusted the future water value, taking in the effects from the policy. It is not set in stone how long this grace period should be. The HPC itself is not a complicated tax, but the monthly average calculation might introduce some thought into assessment. Also, as the RME guidelines mentioned in the background chapter is an instance there was some uncertainty of what would be allowed within the regulation. This analysis work with a grace period of one week. That is, the one week of observations is removed from the dataset before analysis.

Also, on 6. October the HPC was announced to be terminated with retroactive effect from and including 1. October. However, the change was not passed in parliament before 14. December 2023, along with the rest of the state budged for the following year. Still, there was reasonably certainty that the suggestion would be passed as announced. However, power producers still had to report and pay the HPC to the Norwegian Tax Authorities for October and November according to the then current rules but would be corrected in the tax report after the parliament's decision. This uncertainty of when the policy was fully terminated makes the period after the announcement of the termination prone to uncertain effects. Keeping this in mind this period is excluded from the analysis. This exclusion and the one mentioned in the paragraph above leaves a dataset with two parts, pre-HPC (absent) and post HPC (inEffect). An overview of the time-periods mentioned is shown in Figure 6-8.

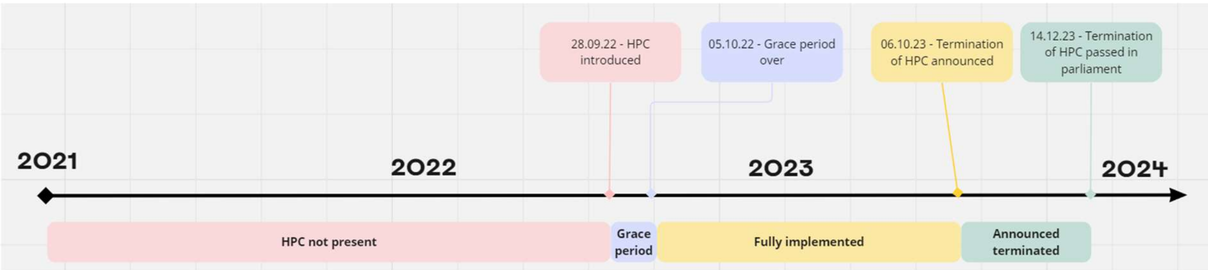


Figure 6-8. Overview of the timeline of the high-price contribution.

7. Methodological Approach

This chapter explains and gives reasons for the econometric approach used to investigate the research questions. The thesis uses statistical inference methods to investigate how the Norwegian high price contribution (HPC) affects the allocation of reservoir hydropower production throughout the day. Also, the chapter discusses some important issues with the data set.

To estimate shifts in production plans through the day resulting from a production tax is complex, but not impossible. Previous research on the effects on production taxes on electricity from hydropower is sparse, which makes it difficult to look to previous research for good approaches to model the situation at hand. However, the topic of modelling supply of hydropower has a lot of previous research. This thesis utilizes the fact that there are sound econometric approaches for modelling the general hydropower supply by keeping production plans to be the dependent variable, controlling for variables that are known to affect hydropower supply from previous studies.

7.1. Econometric Approach

This thesis estimates the supply of hydropower production using a left-censored standard Tobit model (Tobin, 1956). This model is chosen because of the presence of a corner solution responses as introduced in the section on "Production Plans". The reasoning behind the choice of model is discussed in more detail in the following sections. The standard Tobit model, also called the type I Tobit model, is a way to rectify the issue of corner solution responses but can also be used for dealing with censored variables. The model splits the production decision into two parts: first weather to produce and second, how much to produce given that you are already producing.

The Tobit model assumes that there is a latent variable, $ProdPlan^*$, that follows a normal distribution. Here, $ProdPlan^*$ is a concept for the underlying process of deciding how much to produce given that you are already producing. The observed dependent variable, $ProdPlan$, is a combination of $ProdPlan^*$ and the corner solution process. Simply put, when $ProdPlan > 0$ the actual planned production which follows the distribution of $ProdPlan^*$, but when $ProdPlan < 0$ it is optimal to produce zero and 0 is observed instead of $ProdPlan^*$. The observe production plans can be explained as follows:

$$ProdPlan \ = \max\{0, ProdPlan^*\}$$

It can be described to be a function of a set of explanatory variables as in the equation below.

$$\begin{aligned} ProdPlan^* \ = \ & \alpha_0 + \alpha_1 MaxEffect + \alpha_2 ln(filling) + \alpha_3 ln(Price_{Fut}) + \alpha_4 Price_{El} + \alpha_5 Temp \\ & + \alpha_6 ln(Price_{Gas}) + \alpha_7 ln(Price_{Carb}) + \alpha_{8m} month_m + \alpha_9 HPC + \alpha_{10h} hour_h \\ & + \alpha_{11} HPCxhour_h + \alpha_{12} lag(ProdPlan\ ) + u_i \end{aligned}$$

Table 7-1 below gives a more detailed overview of the variables included in the model. In the equation α_0 is the regression intercept and u_i represents the error term. α_i represents the partial effect of the variable, herein referred to as variable estimate. The explanatory variables include maximum installed capacity of the station group ($MaxEffect$), reservoir filling ($filling$), futures electricity price ($Price_{Fut}$), current electricity price ($Price_{El}$), temperature ($Temp$), European gas price ($Price_{Gas}$) and European carbon price ($Price_{Carb}$).

In addition, $month_m$ represent eleven dummy variables for the different months of the year, using January as the reference value. The general effect of the high-price contribution (HPC) as a binary variable which equals 0 before the HPC was introduced and 1 for the period the HPC was in effect. $hour$ represents a dummy for each hour of the day in local time, using the zero-hour as default. Also, interaction terms between HPC and $hour_h$ is added to estimate the difference in hourly allocation of production before and after the HPC was introduced. Lastly, $lag(ProdPlan\ )$ represents the 3-month rolling average of production plan for the station group.

Table 7-1. Overview of variables included in the model.

Symbol	Short Explanation	Data source
$ProdPlan$	Production Plans for each station group. Unit: MW.	RME
$ProdPlan^*$	Latent variable of the process for planned production given that Y>0.	-
$MaxEffect$	Maximum installed effect of each station group. Unit: MW.	RME
$\ln(filling)$	Reservoir filling for the bidding area. Lagg and log-product. Unit: percentage.	NVE
HPC	Binary variable indicating if the high-price contribution (HPC) is absent (HPC=0) of in effect (HPC=1).	Calculated
$hour$	Dummy for each hour of the day in local time (CET/CEST). The number represents the start of the hour, that is, 0 represents the hour from midnight to 00:59.	Calculated
$month$	Dummy for each month of the year.	Calculated
$\ln(Price_{Fut})$	ICE Nordic Power Financial Base Futures (expected future electricity price). 2nd position (contracts 2 months forward in time). Daily closing price. Lagged by two days and log transformed. Unit: EUR/MWh.	Macrobond.
$Price_{El}$	Nordpool hourly spot price for electricity of each bidding area. Lagged by one days and log transformed. Unit: EUR/MWh.	RME
$Temp$	Hourly average air temperature of all weather stations with available time series for one major city in each bidding area. Unit: degrees Celsius.	MET
$\ln(Price_{Gas})$	Futures European gas price. ICE Endex TTF gas price (NDX TFM). Daily closing price. Lagged by two days and log transformed. Unit: EUR/MWh.	Montel
$\ln(Price_{Carb})$	EEX EUSP European Carbon Spot (carbon price). Daily closing price. Lagged by two days and log transformed. Unit: EUR/t.	Montel
$\ln(ProdPlan)$	Variable representing the 3-month rolling average of production plan for the station group.	Calculated

.

The standard Tobit model uses a Maximum Likelihood Estimation method (MLE) approach (Wooldridge J. , 2010) to obtain parameter estimates. MLE is generally asymptotically more efficient than the best GMM estimator but relies heavily on an assumption of conditional normality of the latent dependent variable. If this assumption is not fulfilled, there is a risk of obtaining inconsistent variable estimates. Also, homoscedasticity[12] is an important assumption.

The data analysis is conducted in Python. There have been difficulties finding appropriate packages for the Tobit model in this programming language. A package developed and supplied by professor O. Bergland (NMBU) is utilised in the thesis. The code for the data treatment and analysis is not provided out of concern of showing data for specific station groups, which would break with the agreement with the Norwegian Energy Regulatory Authority (RME) mentioned in the Preface section.

For the second research question the model above is fitted separately for the five different bidding areas.

[12] Constant variance for different levels of the dependent variable.

7.1. Latent Explanatory Variables

The Tobit model presented above, model production decisions and investigates the effect of the HPC on these production decisions. The chapter on "Research Question and Hypothesis" stated that the decision to produce depends on the water value and the price today. The water value is again determined in part by the expectations of the future electricity price, for which Birkedal & Bolkesjø (2016) state that the futures electricity price is used as an unbiased estimator among many hydropower producers. Therefore, futures electricity prices are included as a variable in the model. In addition to the futures electricity price, the futures European Gas price is utilised for reasons stated in the section on "Futures European Gas Price".

As explained in section on "Production Plans", current electricity prices are not known at the time of making bids to the spot price market. This means that the expected price is decisive for production decisions. As hydropower producers´ expected price is latent information, a proxy to model the current electricity price is needed.

One possible proxy is the actual electricity price of that hour (electricity price for short) as it turned out to be. However, this would imply that hydropower producers' expected price is 100% accurate, which is unlikely. Also, the electricity price affects the production of hydropower, but the production of electricity from hydropower also affects the market price. This is because the price is jointly determined by bids for supply and demand through the equilibrium mechanism for each bidding area in the spot market. This describes the presence of simultaneous causality bias which results in an endogeneity in the electricity price of our model. That is, the electricity price is correlated with the error term of the structural equation. This thesis tested including the actual electricity price as a proxy for the expected future price, handling the simultaneity bias by standard Tobit with the two-step approach (Wooldridge J. , 2010, s. 531). However, the author did not manage to find exogenous instruments for doing so and attained better model accuracy for approaches using other variables as proxies for the expected electricity price. One instrumental variable that is not tested in this thesis is the German current electricity prices as utilised in Birkedal & Bolkesjø (2016) applying this approach might be a possible improvement of the analysis.

The section on "Day-Ahead Electricity Prices" stated that the spot price of the day before the hour in question is known when making the production decision. As yesterday's prices are decided before the bids of production today are delivered, they cannot be affected by todays' production. Therefore, these do not suffer from simultaneous causality bias. As this is the latest information available to producers at the time of making bids for production, it is reasonable that they utilise this information when making production decisions. Therefore, the thesis includes the lagged current electricity price, as described in the section on "Day-Ahead Electricity Prices", in our estimation. In addition, the section on "European Carbon Price" argued that European carbon prices can affect Norwegian electricity prices. Demand is an important driver of the price as previously explained, but it cannot be included directly as it affects several of the other explanatory variables. Instead, the temperature is included as a proxy. To account for differences in peoples' habits and changing business cycles through the year hourly and monthly dummies were added to catch some of this variation.

7.2. Corner Solution Outcomes

As mentioned in the data-section, data on production plans shows clear signs of corner solution responses. Corner solution responses is a type of limited dependent variable (LDV). An LDV is broadly defined as a dependent variable whose range of values is substantively restricted (Woolridge). A variable subject to corner solution responses if it is "zero for a nontrivial fraction of the population but is roughly continuously distributed over its positive values" (Wooldridge J. , 2019, s. 571). A presence of corner solution responses does not imply any issues with data observability, rather the distribution of responses.

In this case, the null responses come from that it is economically optimal to produce nothing in certain hours. However, the condition is decided by the relationship between the marginal revenue and the water value, which is latent. Simply put, it will be optimal to produce zero if the water value is higher than the marginal revenue of producing now. This means that for many hours it will be economically optimal not to produce.

This results in that the distribution of the dependent variable piles up at zero resulting in no conditional normal distribution of the dependent variable. This means that assumptions of the linear model are not fulfilled. Also, piling the dependent variable around zero probably leads to heteroscedastic variance. When not accounting for this in the linear model this can result in obtaining negative fitted values for the dependent variable, which does not make sense for the sake of this analysis. Also, showing coefficients in a linear fashion as having a constant partial effect on E(y|x) can be misleading. However, the linear model might still be a good fit around the mean values of Y.

The issue of corner solution outcomes can be dealt with by fitting a model which splits the production decision in two parts: first whether or not to produce and second, how much to produce given that you are already producing. Both the standard Tobit model and double hurdle take this approach. Double hurdle involves a two-stage decision-making process allowing for different variables to affect the participation decision and the production decision while the Tobit does not. In this case, the relationship between price and water value will affect both decisions and it can be concluded that the standard Tobit model will be the most correct representation of our data.

7.1. Model Assumptions

A systematic walk-through of all model assumptions can be found in the appendix. The standard Tobit model relies on the assumptions of heteroscedasticity and normal conditional mean of the latent dependent variable. If these assumptions are broken, the Tobit estimations $\hat{\beta}$ are inconsistent for β (Wooldridge J. , 2010, s. 533). However, in our corner solution problem the β is not of interest, but rather the partial effect of $E(y|x)$, which can be similar with and without presence of heteroscedasticity. The thesis finds the conditional distribution of the latent dependent variable not to be normally distributed, although it is symmetrical around zero. For the second research question the NO2 and NO3 models are even less normally distributed than the overall model. Also, our errors show signs of heteroscedasticity, another assumption of which our model relies on. This might introduce model results with a wrongly specified variance. Data filtering also introduces breaks to the assumption of random sampling. Lastly it is probable that there is a presence of unobserved effects, described in the next section. Still, the estimation approach presented and utilised in this thesis is the approach of highest accuracy of all methodologies tested.

7.2. Serial Correlation

Serial correlation is an issue to discuss in all data with observations over time. There is a presence of serial correlation when the value of your dependent variable is dependent on past observations. That is, it occurs when the regression errors of different time-periods are not independent of each other. Serial correlation can happen due to various reasons, including incorrect model specification, or omitted variable bias (OVB). Omitted variables can be due to several reasons, but this thesis likely has unobserved effects tied to the station group that are not accounted for in the analysis. Station group-specific variables are not possible to match with the data as it is anonymized. This leads to dependence in the distribution of production plans for different time-periods.

The standard Tobit model is designed to handle cross-sectional data and deals with the issue of corner solution response, but it does not specifically account for serial correlation. Hence, the approach taken in this thesis does not specifically address the presence of serial correlation as it fits the model to the entire dataset as one large cross-sectional dataset of size NT (NT= 592 402). A presence of serial correlation does not cause bias in the regression coefficient estimates, but it increases Type I errors (rejecting the null hypothesis when it is true). In other words, we are more likely to reject the null hypothesis when it is true, which we must take into consideration when assessing model results.

To reduce the presence of serial correlation the thesis includes a lagged dependent variable ($lag(ProdPlan\ )$) in the form of a 3-month rolling average of production plan for the station group. This was added on the foundation that Birkedal & Bolkesjø (2016) concluded that adding a lag structure to their model could improve the predictive power of the model. High past production affects the reservoir levels for each single reservoir today. Therefore, serial correlation from this omitted variable (reservoir level of each station group) might be reduced by including this lagged dependent variable.

One way of dealing with serial correlation is fitting a panel Tobit model as the methodology allows for serial dependence (Wooldridge J. , 2010). However, this would require advanced variance specification, but the author has not been able to locate a variance specification that is valid for the context at hand (T>N) in the literature available. Also, such variance specification is not currently available in the packages used for estimating the Tobit model. In total, we deem that accounting for serial correlation in this manner is outside the scope of a thesis.

Panel data methods are known to be used to obtain estimates on unobserved effects that are constant over time, thereby reducing serial correlation. It is known that when T is large (which is the case here), and especially when N is small, one must exercise caution in using the fixed effects (FE) estimator, excluding this as an option. However, panel data methods do not deal with the presence of corner solution responses, meaning that the estimates of such a model would have the right sign on the coefficient, but be inconsistent. Also, the author was not able to find panel data methods that are computationally possible for a specification for hourly dummies, which is a fundamental requirement following the research question.

7.3. Other Data Issues

The model runs all bidding areas as one and does not specifically address that different bidding areas are affected by different factors. This means that it might be factors specific for each bidding area that can affect the production, e.g. grid bottlenecks or the mix of consumers on the demand side. Also, the European carbon and gas price as instruments might not be of large importance in the northern bidding areas. Second, there is an unequal number of station groups in each area, making the different bidding areas non-equally represented in the analysis.

7.4. Model Performance

This thesis does not put much weight on evaluating R^2 for assessing model performance. The tobit model finds its estimates by using a maximum likelihood (ML) approach whose goal is not maximize R^2 unlike least squares estimators. For ML types of estimators, R^2 is therefore not a good measure of the model fit. In general, R^2 is solely a measure of in-sample performance, which might not be a good indicator of the methods prediction accuracy. To measure out of sample performance a K-fold validation (K=4) is performed to split the data into random training and testing datasets. It then fits the model on the training dataset and measures the mean squared error (MSE) on the testing dataset. MSE is the average of the squared distance between the actual observed dependent variable in the test dataset and the predicted value of the same observations given the parameters obtained from the training dataset. The K-fold validation then takes the average MSE across the K folds. This is a much-used technique for measuring out-of-sample performance of an estimation method.

7.5. Estimates from the Tobit model

This thesis wants to investigate the changes to allocation for hours in the day. In the model above these *hourly effects* are represented as a set of dummies for each hour of the day. The *change* to the hourly allocation is included in the form of interaction terms between hours and the HPC.

Differences in production between hours of the day could be modelled in other ways. First, a similar technique for obtaining hourly estimates before and after the HPC was introduced, is to estimate the supply of hydropower production separately on the two parts of the datasets explained in section 6.10: pre-HPC and post-HPC. A result of this is that no variable for the high-price contribution (HPC) is explicitly included in the model equation, which is the reason why this approach is not utilised in this thesis. However, the effect of the HPC is implicitly included as the difference in estimates between the two parts of the dataset, but such results are more difficult to interpret. Another alternative is to make production plans some sort of difference-variable between hours in the day. Our conclusion is that this would remove much information as only one estimate is obtained and there are many hours in the day.

Partial Effects

From the model explained above it is important to note that the variable estimate, α_i, is not the standard variable coefficient as we know it from standard ordinary least squares. Instead, they are the partial effects of the explanatory variables on the dependent variable $ProdPlans$. For simplicity it is referred to the α_i-s as variable estimates in the rest of this thesis.

What of the estimates from the Tobit model to obtain depends on the fundamental reason for using the model to begin with. The setup can be utilised for both censored and corner solution outcomes, of which the last is applicable to our situation. For data censoring interest would typically be in the model determining the latent y-variable $ProdPlans^*$, that is, the expectation of the latent variable given the explanatory variables $E(ProdPlans^*|x) = x\beta$. For corner solution responses on the other hand, one wants to investigate the total effect on production from the HPC, that is $E(ProdPlans|x)$. The reason for this is that the latent variable $ProdPlans^*$ does not have any meaningful interpretation in the given context. What is of interest for the electricity system is not the production in a certain hour after removing null observations, it is the total production in those hours. Oppositely to $E(ProdPlans^*|x)$, the partial effects on $E(ProdPlans|x)$ are non-linear in its form. These are obtained by multiplying the beta estimates with an adjustment factor. This makes the variable estimates roughly comparable to OLS estimates. The adjustment factor is computed by average partial effect (APE). The calculation is performed differently for continuous and discrete (including binary) explanatory variables, like stated in Wooldridge (2019).

8. Results

8.1. Results – RQ1

This section reports on results for the first research question. That is, how does the Norwegian high price contribution (HPC) affect the allocation of reservoir hydropower production throughout the day? The chapter starts by investigating the research question with descriptive statistics, looking at the difference in production before and after the HPC was introduced. Then, results from the statistical inference methods described in the section on “Econometric Approach” is shown.

RQ1 Descriptive Statistics

Figure 8-1 looks at the overall difference in the density of production plans before and after HPC. As the period before the implementation of HPC will be longer than that after resulting in different sample sizes, the figure ensures that the density for each group is normalized separately, showing the actual density of each 'HPC' state without affecting each other. This is useful for comparing distributions whose samples may vary in magnitude. In the figure it looks like the production levels are below zero – this is not the case for the real distribution, but a function of the density function. Observe that the two distributions are relatively similar but have some variations in the lower production levels. A somewhat larger part of the pre-HPC data is centred around zero and the interval 100-150, compared to post-HPC data. The post-HPC data on the other side lies over the pre-HPC data for production levels between 20-60 MW.

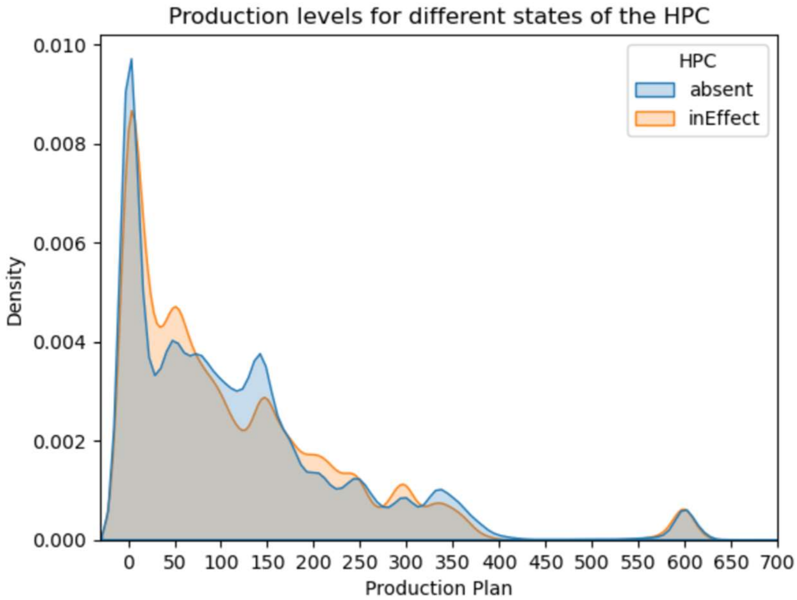


Figure 8-1. Density plot of production levels for different states of the high-price contribution normalized separately. Here, “absent” marks pre-HPC levels and “inEffect” marks post-HPC levels. Production levels are measured in MW.

This paragraph investigates the cross-sectional distributions for different hours. Figure 8-2 below shows the average hourly planned production for hours of the day, before the HPC was introduced (absent) and while it was in effect (inEffect). Observe that average planned production between 21h and 6h is higher when the HPC was in effect than before. The opposite is true between 6h and 20h, where average planned production was higher before HPC was introduced compared to after. This is in line with our hypothesis for the change to daily load resulting from HPC. It is also in line with the result from Figure 8-1 above, that the share of observations among the very lowest production levels is lower when HPC was in effect, compared to before.

To summarise, the average production for the different hours is flatter after the HPC took effect, than before it was introduced. Production plans during night-time (21 -06) hours are on average higher than before HPC was introduced, and the opposite is true for day-time hours.

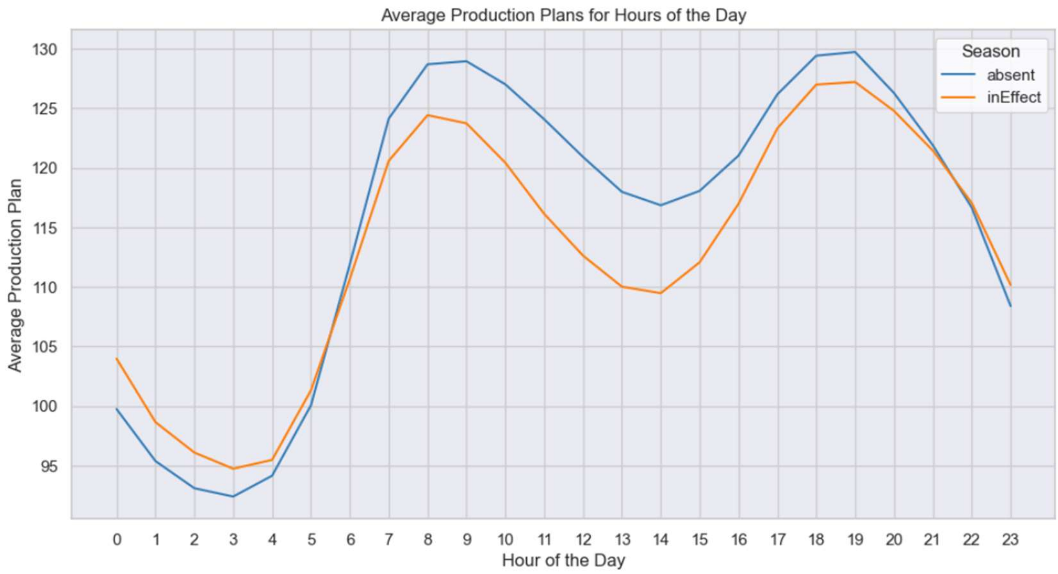


Figure 8-2. Average production plans for different hours of the day, for different states of the high-price contribution. Here, "absent" marks the period before HPC was introduced and "inEffect" represent the period while the policy was in effect. Production levels are measured in MW.

RQ1 Regression Results

This section provides estimates for the partial effects and significance of the included variables on the planned production. Look to the section about "Partial Effects" on how to interpret the results. To make the results easier to digest for the reader the section split up the results in three paragraphs: hourly dummies, other explanatory variables, and monthly dummies.

Hourly Dummies

Variable name	Partial Effects hours	p-values hours	Partial Effects interactions	p-values interactions
h1	-4.46	0.000	-1.47	0.324
h2	-6.79	0.000	-1.72	0.250
h3	-7.70	0.000	-2.32	0.120
h4	-6.25	0.000	-3.17	0.033
h5	-0.78	0.392	-2.60	0.081
h6	10.69	0.000	-5.11	0.001
h7	22.60	0.000	-7.50	0.000
h8	27.61	0.000	-8.38	0.000
h9	28.95	0.000	-9.43	0.000
h10	28.38	0.000	-10.83	0.000
h11	26.73	0.000	-12.21	0.000
h12	24.58	0.000	-12.52	0.000
h13	22.44	0.000	-12.30	0.000
h14	21.71	0.000	-11.80	0.000
h15	22.76	0.000	-10.49	0.000
h16	25.26	0.000	-8.60	0.000
h17	29.71	0.000	-7.57	0.000
h18	32.17	0.000	-7.15	0.000
h19	31.82	0.000	-7.29	0.000
h20	28.03	0.000	-6.35	0.000
h21	23.22	0.000	-5.29	0.000
h22	17.63	0.000	-4.35	0.003
h23	9.51	0.000	-3.02	0.042

Table 8-1. Variable estimates for hourly dummies from the standard left censored Tobit model described in section 7.1. Columns marked with hours show the "pure" hourly estimates while columns marked with interactions displays the results of the interaction terms between the same hours and HPC.

We start the chapter off with the results of our variable of interest, the hourly estimates, show in Table 8-1. The table displays partial effects (variable estimates) and p-values for two sets of variables: the "pure" hourly estimates, and the interaction terms between the same hours and the HPC. The pure hourly estimates (column 2) are the partial effect on production plans in the respective hour, when comparing with the reference hour (00:00-00:59). The reference state refers to the situation when all other time-dummies of that variable is set to zero. The interaction term estimates (col 4) can be interpreted as the partial effect on production in the respective hour due to the HPC, compared to the reference hour. Simply put, it is the *change* to allocated production due to HPC in that hour, compared to the midnight hour.

We observe that the pure hourly estimates are significantly different from zero at the 1% level (at least) for all variables except h5 which is not significant. For the interaction terms on the other hand results are not so certain. Here, variable estimates are significantly different from zero at the 1% level for the hours 6-22, and significant at the 5% level for 4h and 23h. These results indicate that there is a statistically significant difference in hourly allocation after the HPC came into effect. Observe that this is mainly the daytime hours.

To simplify the illustration of the partial effects from the table above they are displayed graphically in Figure 8-3. In the figure the pure hourly estimates are displayed in blue. The partial effects of the interaction terms (orange) are displayed as *deviation* from the pure hourly estimates. Simply put, the interaction estimate is subtracted from the pure hourly estimate for the respective hour.

First commenting on the overall trend, observe that HPC-interaction estimates lie lower for all hours of the day than the pre-HPC estimates. For the day-time hours this is in line with our hypothesis and with the descriptive statistics presented further up in this chapter. Observe a clear negative deviation from the pure hourly estimates. This indicates that during day-time hours the hourly trend becomes less decisive for production plans when the HPC is in effect than when its absent. That is, it indicates a more even production through the daytime hours after HPC than before.

The section on "Demand-Driven Power Market" stated that challenges in the power balance (Norwegian: effektbalanse) occur during peak load hours in the morning (07-11) and in the afternoon (17-19) during the coldest winter days (Thema Consulting, 2022). Observe that the interaction terms of the hours experiencing troubles with the power balance mentioned by Thema all have statistically significant estimates. This indicates that the HPC induces lower production in the hours of the day where the power balance is most likely to occur, creating possibly harmful effects for the electricity system.

However, the largest partial effects on the interaction terms are at and around 12h. This result does not provide a clear answer of which of the two effects mentioned in the section on "Research Question and Hypothesis" that is the strongest, but it is reasonable to assume the effect through the water values is the strongest as there is greater uncertainty of future prices than of tomorrows'.

For the night-time hours the trend is more difficult to explain, and not in line with the descriptive statistics further up in this chapter. Here, the results indicate that production during night-time hours is lower when the HPC is in effect compared to when HPC is absent, when controlling for other variables.

This could indicate that the overall production in the year after the HPC was introduced have a total lower quantity of water available to production had if reservoir filling and the HPC variable was not controlled for. Still the reservoir filling is for each bidding area and not for the specific station groups, possibly introducing some omitted variable bias in our results. The reservoir filling not explaining the full variation of that factor is an example of the included explanatory variables included not explaining the variation they are supposed to.

Another example might be the temperature which is lower during nigh-time hours and is only included for one municipality in each bidding area.

Also, variables not included in the analysis that are correlated with the nigh-time hours can affect these results. Temperature is the only variable included for explaining price variations from demand. However, the *felt* temperature might be a more appropriate indicator for demand, which is affected by factors such as wind and daylight. These can be vary depending on the hour of the day.

Another explanation could be that the guidelines on market manipulation set by RME, explained in section 2.3 are not followed. However, keep in mind that the interaction terms during nigh-time hours are not significant, and one cannot draw the conclusion that this is the overall trend. The lacking significance is a natural result of partial effects being closer to zero.

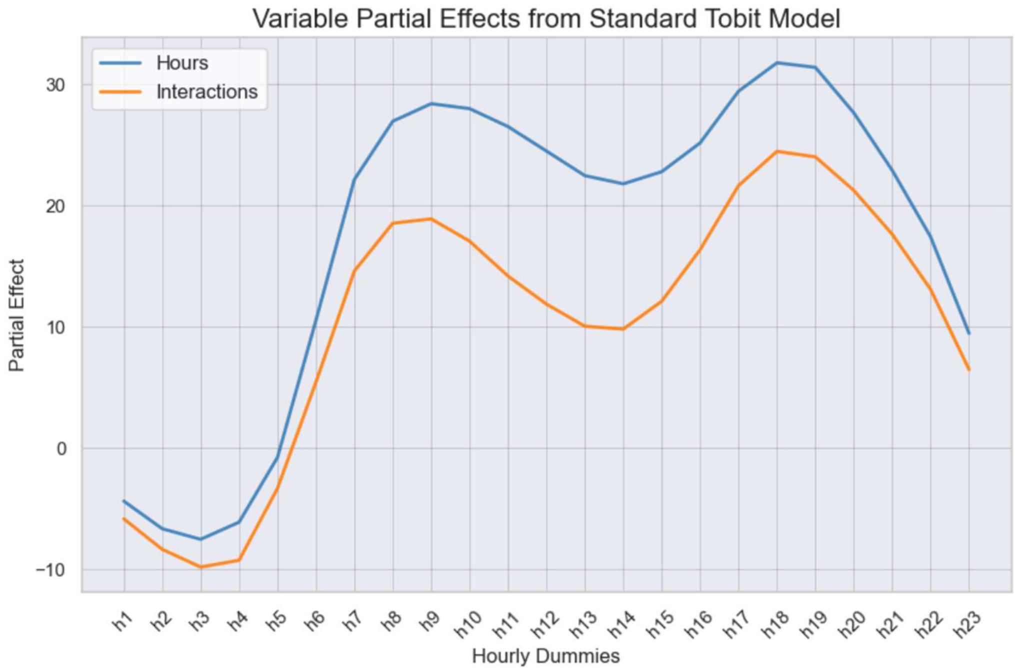


Figure 8-3. Variable estimates for hourly dummies from the standard left censored Tobit model described in section 7.1.

Other Explanatory Variables

Variable name	Partial Effects	p-values
Intercept	-151.64	0.000
Installed Capacity	0.06	0.000
ln(Reservoir filling)	32.54	0.000
ln(Futures Electricity Price)	7.27	0.000
Temperature	-2.21	0.000
ln(Gas Price)	-16.14	0.000
ln(Carbon Price)	38.42	0.000
HPC	17.35	0.000
lag(Production Plan)	0.90	0.000
lag(electricity price)	0.05	0.000

Table 8-2. Estimation results for continuous variables from the standard left censored Tobit model described in section 7.1.

Table 8-2 above show the variable estimates and p-values of all continuous explanatory variables. The coefficients can roughly be interpreted as the partial effect on production plans from a one-unit increase in the explanatory variable. First observe that the continuous variable estimates are all statistically significant different from zero at least at a 1% significance level. Intuitively, the installed capacity tells us something about the size of the station group. Larger station groups can be expected to produce more electricity, resulting in a positive variable estimate. This is in line with our result. The size of the estimate might seem small compared to other variable estimates, but keep in mind that installed capacity is not log-transformed in this analysis.

Also as expected, the log-transformed reservoir filling obtains a positive variable estimate. Intuitively, a higher degree of reservoir filling in the bidding area indicates that inflow is generally higher, leaving more water available for production. Thereby, the water value is lower, and it becomes optimal to produce more today. Although the reservoir filling might not represent each station group in the entire bidding area well, one would still expect the sign of the reservoir filling variable to be positive, as observed.

As stated in the section on "Temperature" lower temperatures are expected to increase production plans in total, when assessing a linear functional form of the temperature variable. That is, a negative estimate on the temperature variable, which is exactly what is observed in the variable estimates. The temperature is not log-transformed in this analysis.

Intuitively, the lagged current electricity prices are expected to have a positive sign. This is because a high electricity price yesterday is often connected with a higher price today, and hence also higher expected price of today. This results in higher production plans, which is in line with our finding. Keep in mind that the lagged current electricity price is not log-transformed following from the discussion in the section on "Day-Ahead Electricity Prices".

The section on "Data sources" showed that development in the gas prices and future electricity prices are similar over time. This can lead to the estimator not being able to distinguish from which variable to assign the effect, possibly resulting in variable estimates that are not intuitive. However, the two variables do not suffer from perfect multicollinearity and their p-values are low indicating that they have sufficiently distinct effects on production plans. Therefore, both variables are allowed to be in the estimation. Intuitively, a higher future spot price should result in higher water values resulting in a decrease in today's production plans. Thereby, one expects a negative estimate. In the table above, observe that the estimates for the future electricity price do not have the expected sign.

One reason for this might be that the futures electricity price is often connected with the current electricity price, which moves in the opposite direction. However, in the thesis data does not show a strong correlation between current electricity prices and futures electricity prices, which are lagged by one and two days respectively. Another explanation for this coefficient might be that it reflects more aggregated tax adaptions; that the HPC result in future electricity price being valued differently. This is difficult to conclude as the variable is estimated based on both the HPC-absent and the HPC-inEffect period. It can be concluded that the variable estimates on the futures electricity price indicate that our results should be regarded with caution.

Following from the discussion in the section on "Futures European Gas Price" one expects the future gas price to have a negative sign. This is because higher future gas prices result in higher future electricity prices, increasing water value and lower production today. This is in line with our finding above. There is high correlation between the future gas price and the carbon price, but this does not seem to cause large issues in our model as can be observed here. The carbon price is expected to have a positive sign as higher carbon prices tend to drive up the electricity price in Europe, further increasing the current Norwegian electricity price. This is also in line with our results.

Observe the partial effect of the HPC variable, which is positive. As mentioned in the section on the hourly estimates indicate an overall trend in production plans being higher for HPC-absent than HPC-inEffect. Such an effect is reflected in the HPC variable, as it is positive in the results of this thesis. However, as the analysis does not control for all time-varying variables this positive estimate can simply reflect that there are time-trends that are not accounted for in the analysis. Also, the seasonal effects of the HPC might result in this average total effect.

Intuitively, the lagged production plan should have a negative sign, as it reflects higher production in the past, leaving less water to produce today, but a strong positive sign is observed. This can indicate that the production level itself is correlated with past production levels, e.g. that the production level of a station group has a max production capacity at which it produces for a share of the observations. Also, the lagged production plan is strongly correlated with the installed capacity. In total, this indicates that the lagged production plan controls for some of the unobserved effects mentioned in the section on "Model assumptions".

Monthly Dummies

Variable name	Partial Effects	p-values
m2	-4.94	0.000
m3	-2.61	0.000
m4	5.33	0.000
m5	2.56	0.000
m6	5.61	0.000
m7	12.68	0.000
m8	12.61	0.000
m9	2.26	0.000
m10	0.05	0.935
m11	7.58	0.000
m12	-0.13	0.829

Table 8-3. Variable estimates for monthly dummies from the standard left censored Tobit model.

Our estimator obtains estimates for monthly dummies. For our monthly estimates January is set as the reference. From Table 8-3 observe that all monthly estimates, except October and December obtains estimates that are statistically significant different from zero at a 1% significance level. To observe the trend more clearly between the variable estimates they are portrayed in Figure 8-4 below. These are also the two months with partial effects closest to zero.

Overall, there seems to be a clear seasonal trend with some variations. First, observe the highest estimates in July and August, with local maximum in April and November. Lowest estimates are obtained for February. The estimates observed may be due to differences in household activity and business cycles as the estimator already controls for temperature differences, reservoir filling, and price variations through the year. The monthly dummies might also reflect other seasonal factors. E.g. the HPC was introduced in October 2022, a month where a dip in production can be observed. This might indicate that the changing market conditions could have led to uncertainty of the new policy resulting in low production plans. Overall, it can be concluded that estimates of our monthly variables can be caused by several factors, making results uncertain.

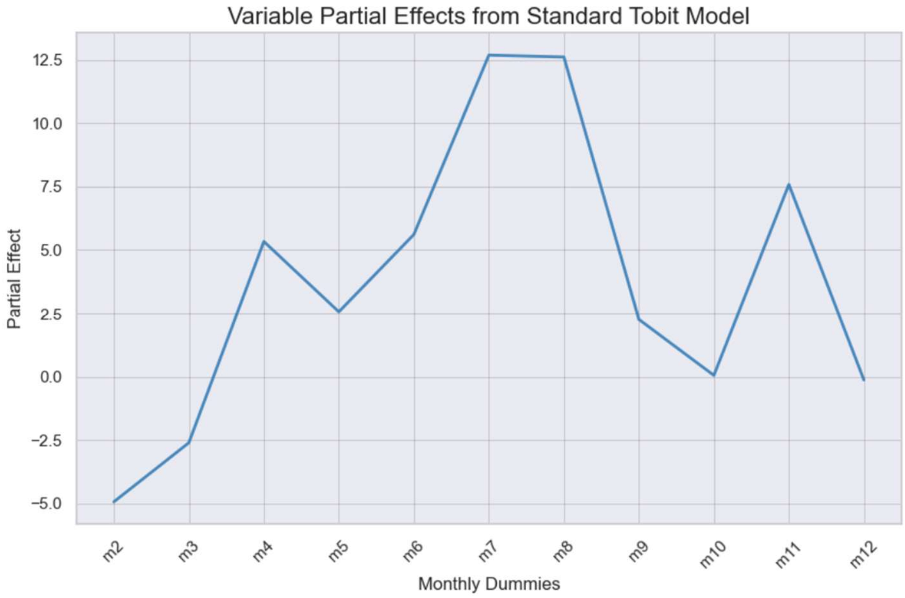


Figure 8-4. Variable estimates for monthly time-dummies from the standard left censored Tobit model described in section 7.1.

8.2. Results – RQ2

The second part of the chapter report on results for the second research question. That is, "Is the effect from RQ1 dependent on the general price level in different bidding areas?", RQ1 being how the allocation of reservoir hydropower production between hours in the day affected by the Norwegian high price contribution (HPC). The section widely follows the same structure of the chapter above but display results for each bidding area.

RQ2 Descriptive Statistics

We start the section looking at differences in hourly allocation of production before and after the introduction of HPC for different bidding areas, displayed in Figure 8-5. First, notice that the average production plans for hours of the day is relatively similar before and after the introduction of HPC for NO4, only nigh-time hours lying lower for HPC-inEffect. Only NO2 follows the same pattern as in Figure 8-2, with HPC-absent higher than HPC-inEffect production during night hours for then to swich for daytime hours. NO3 follows a somewhat similar trend, only here HPC-absent production plans are higher than HPC-inEffect for the entire day. Lastly, NO1 and NO5 follows similar patterns with the HPC-absent production being higher for all hours of the day. This is in line with Figure 5-3 further up where very similar average hourly prices for NO1 and NO5 was seen. Keep in mind that the differences between the bidding areas here might be due to differences in explanatory variables who are not controlled for in these descriptive statistics.

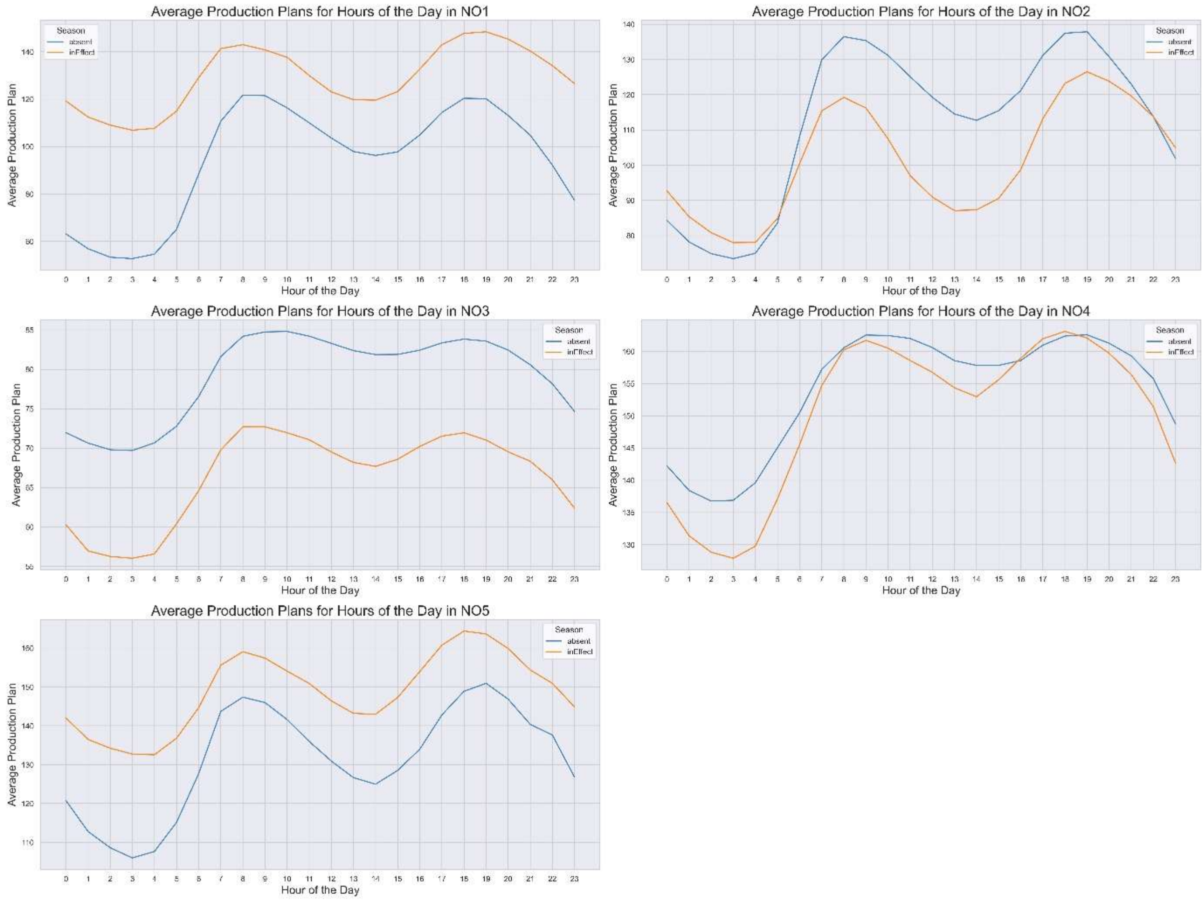


Figure 8-5. Average production plans for different hours of the day, for different states of the high-price contribution, split on the different bidding areas. Here, "absent" marks the period before HPC was introduced and "inEffect" represent the period while the policy was in effect.

RQ2 Regression Results

This section gives variable estimates when controlling for other explanatory variables, using the methodology explained in the section on "Econometric Approach" run on the different bidding areas separately, shown in Figure 8-6. In doing so each model estimate is run on much less data, providing less secure estimates. The section only displays results only for the hourly estimates, but information on other variable estimates can be found in the appendix. The estimates represent the partial effect of the hour compared to the midnight hour (0h), when controlling for other explanatory variables. In the figure the pure hourly estimates are displayed in blue. The partial effects of the interaction terms (orange) are displayed as *deviation* from the pure hourly estimates.

From Figure 5-3 showed that average spot prices are generally lower for all hours of the day in NO3 and NO4. Observe that the same bidding areas, NO3 and NO4, have resembling variable estimates in the regression results with estimates for the interactions being lower than the pure hours estimates during nigh-time hours. However, for the daytime hours both the relationship between the pure hour estimates and the interactions estimates differ between NO3 and NO4, with interactions being slightly positive for NO4 and slightly negative for NO3.

Figure 5-3 also showed that average spot prices are above the 0,7 threshold for all hours of the day in NO1, NO2 and NO5. From Figure 8-6 below observe that both NO1 and NO2 obtain quite similar results with HPC-absent estimates being around the same level or lower than the HPC-inEffect estimates, with the difference being larger for peak-hours. This trend is like that of the overall model. NO5 follow a similar pattern as NO1 and NO2, only here the interaction estimates are more clearly positive than the pure hourly estimates for night-time hours. Also, the divergence during day-time hours is not as large as for NO1 and NO2. Notice that NO1 and NO2 followed widely different patterns in Figure 8-5, while their trends are more similar here. This indicates that much of the variation in these bidding areas can be explained by the other variables controlled for.

The partial effects are significant at the 1% level for NO1 and NO2 in the hours 6-22 (inclusive), and at the 5% for 23h. No partial effects of interaction terms are significant for NO3 and NO4. For NO5 the partial effects are statistically significant from zero at the 5% level for the hours 7-10 and 19-20. All variables that are not time dummies obtain significant results at the 1% level, similarly to the overall model.

These results can be due to bidding-area specific factors which are not accounted for in the analysis. There are few observations of station groups in NO1, but if this affected results it should be represented in the p-values of our coefficients. The consumption mix in NO1 is also known for largely consisting of households. Also, especially NO2 is more closely connected to the European electricity grid.

When it comes to the variables that are not time-dummies all variables have the same sign as in the overall model, with two exceptions. The HPC variable is negative for NO3, and the futures electricity price is negative for NO1, NO2 and NO3. As discussed for the first research question a negative sign of the futures electricity price is intuitive. Therefore, these results indicate that the results of NO4 and NO5 should be regarded with caution. It is large variation in the coefficients of the monthly dummies. This can just indicate that different consumption groups are present to different degree in the different bidding areas, thereby representing real differences in business and household cycles. However, the significance of monthly dummies are overall noticeably lower in NO1 than in the other bidding areas.

The results indicate that the effect of the HPC on hourly allocation of production do depend on the general price level. NO1, NO2 and partly NO5, all high-price bidding areas, shows a significant reaction in hourly allocation during day-time hours similar to that of the overall results. The results for NO3 and NO4, the northern low-price bidding areas, is inconclusive.

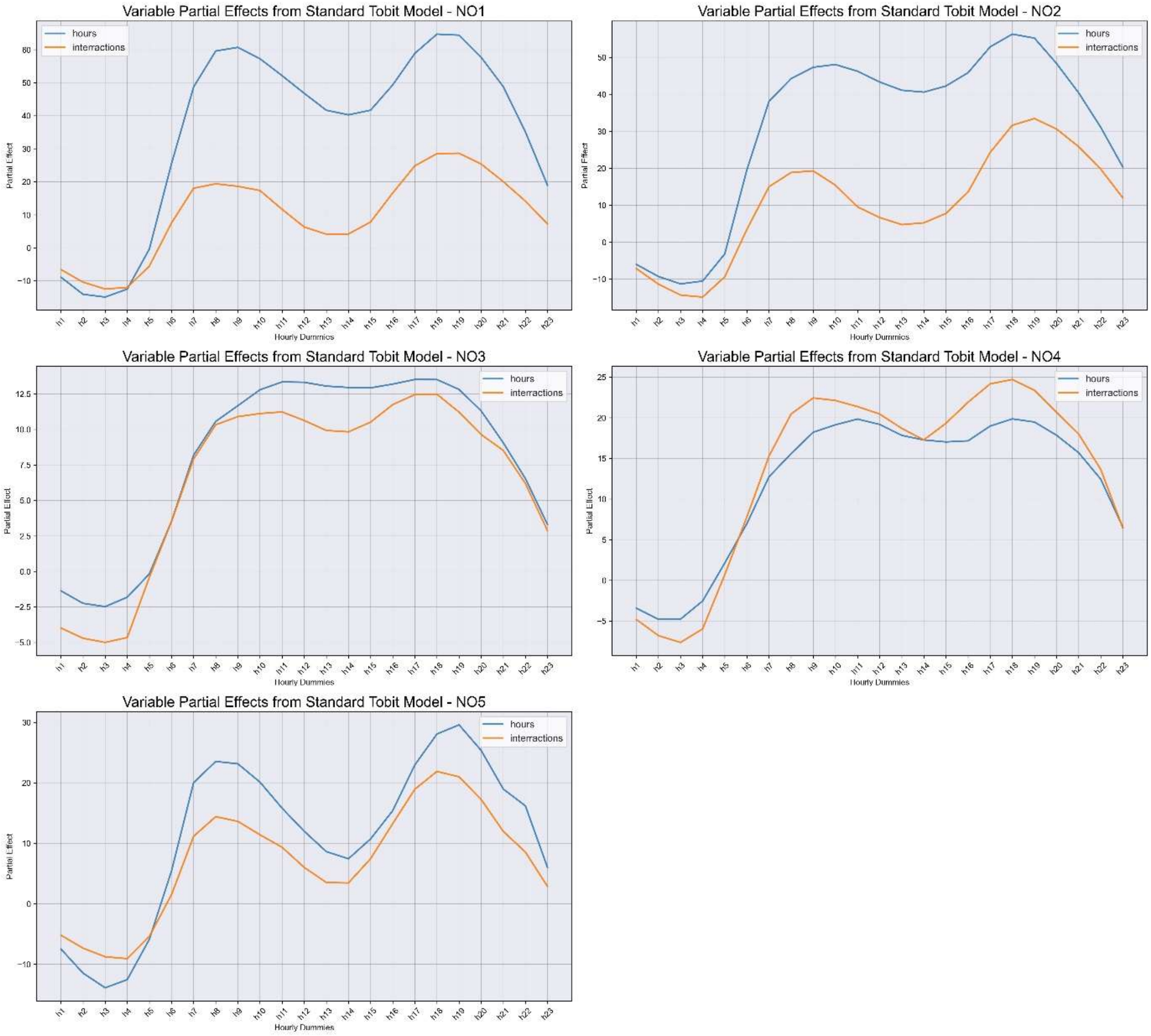


Figure 8-6. Variable estimates for hourly dummies from the standard left censored Tobit model described in section 7.1, split on the different bidding areas.

9. Discussion of the Methodology

This chapter discuss the results presented in the past chapter, potential shortcomings of the analysis, and what measures might be taken to account for these issues.

9.1. The Data

As our study takes place in a real-life market and not a controlled experiment any conclusion on causal effects is difficult. However, having a control group in the data could have been an advantage for better distinguishing the effects of the high-price contribution (HPC). This has been tried obtained,but was not possible due to data privacy concerns. The author recommends that institutions with the relevant access utilise this by looking at specific power plants right bellow and right above the threshold to observe their response to the implementation of the HPC. An alternative approach might be to use production in other Scandinavian countries or the northern bidding areas as control groups.

The HPC was active for one year only, resulting in only one observation for each season, after its implementation. This produces difficulties for the estimation as the electricity system is highly affected by seasonal patterns. As mentioned in the chapter "Research Question and Hypothesis" distinguishing weather the within-day and seasonal effects of the HPC dominates the total production for a specific hour of a day can be difficult. Due to the few observations on seasonal dependencies as the HPC was only present for one year, giving only one observation for each season, one can here confirm that distinguishing these effects is difficult. This was solved in the thesis by focusing on hourly differences in production levels, and not investigating the seasonal effects of the policy.

Lastly, data on production plans are retrieved for only reservoir hydropower. However, the reservoirs might be so small that they in practice operate like run-of-river plants. This might introduce error to our analysis which is not possible to control for with the dataset utilised.

9.2. The Econometric Setup

This thesis investigates the research questions by adding interaction terms between the HPC and hourly estimates. An alternative to the approach of estimating the effect of the HPC on hourly allocation would be to run two separate models with only hourly dummies, then comparing the result of the model on the two datasets. Such an approach would allow for all partial effects to vary between the two models but would not provide variable estimates for the HPC effect on hourly allocation specifically.

Second, the thesis uses the futures prices of electricity and -gas as proxies for the water value, and lagged current electricity prices, carbon prices and temperature as proxies for the expected current price. It is not certain that this specification controls for all relevant variables, or that the included explanatory variables reflect the full variability in the factor it is measuring. This might result in omitted variable bias (OVB). The chosen setup does not control for European gas storage, which might indicate future electricity prices in Europe, and current European gas prices are not included. Neither do the thesis obtain data on the reservoir filling in the specific station group. Also, other weather factors outside of the temperature might affect demand, and thereby explain more of the expected current electricity price. Further improving the model specification might be a possible improvement of the analysis.

Also, OVB might be present in the form of unobserved effects. That is, there are factors specific to each single station group that is not obtained data on such as the reservoir size and the production capacity. Also, one might imagine that different owners have different technological solutions for optimizing production plans or differing requirements from their board which might affect production strategies. Even if this information was obtained, one would not be able to match it with our dataset as station groups are anonymized. However, data on the maximum installed capacity of each station group is obtained, which reflects the general size of the station group. Still, this does not account for all station-group specific effects.

Both the above-mentioned types of OVB can result in a presence of serial correlation in our estimation. That is, our error term in one period not being independent on the error term from previous periods. This bring us over to the next issue regarding the model at hand - that our general estimator might not be the correct specification. The standard Tobit model utilised in this thesis corrects for the presence of corner solution responses in our dependent variable, but it does not specifically account for a presence of serial correlation. However, if does try to reduce the presence of serial correlation by including a lagged dependent variable as an explanatory variable. Serial correlation does not cause bias in the regression variable estimates, but it increases type I errors (rejecting the null hypothesis when it is true). In other words, our standard error will be too small. This means that the significance level of our variables should be regarded with caution.

One might reduce serial correlation in the form of unobserved effects using panel data methods, but these would not take into account corner solutions. Therefore, choosing between panel data approaches and the Tobit model becomes a tradeoff – panel data methods reduce the variance issues introduced by serial correlation but is inconsistent due to missing handling of corner solution responses while the Tobit model handle the corner solution responses but does not account for serial correlation. Using a panel Tobit model is a method for better handling serial correlation simultaneously as accounting for corner solution outcomes. However, this would require a highly advanced variance specification which is outside the scope of a thesis. Better handling of this serial correlation in our data is one suggestion for future research on the topic at hand.

The standard Tobit model is highly reliant on the assumptions of a normal conditional mean of the latent dependent variable. Results show that this distribution is not especially normally distributed, although it is symmetrical around zero. Also, our errors show signs of heteroscedasticity, another assumption of which our model relies on. This might introduce inaccurate standard errors in our results. Still, the estimation approach presented and utilised in this thesis is the approach of highest accuracy of all methodologies tested. For the second RQ, the bidding areas NO2 and NO3 obtained residuals of the latent underlying variable that are even further from being normally distributed than the overall model, possibly providing issues for our estimator.

For the RQ2 estimates the model fitted is the same for all bidding areas. This was done to ensure that it was not differences in the included variables that led to differences in estimates. Different bidding areas might be affected by different factors, and this is not accounted for in our analysis. Still, low importance of a variable for the specified bidding area is reflected in the estimate of that variable. However, one opportunity for further research is to investigate possible adjustments of the included factors to the respective bidding area.

9.3. Other Factors Affecting Production

This thesis has tried to include moments of all main factors affecting the production of hydropower. However, it is possible that the thesis does not specifically account for all factors affecting production.

First, this thesis investigates the effects only on the production itself resulting from the introduction on HPC, and disregards changes to investments by keeping only station groups that have not had changes in station group organisation and no changes to installed capacity during the period in question. However, information on changes in station groups is not easily accessible, and some changes might not have been excluded. Further investigating the investment effects of the policy could be an interesting development on the topic.

The analysis disregards the fact that the hydropower producers may also participate in the intraday- market as one cannot distinguish what market the different parts of the production are assigned to. This is a possible source of error. One advantage of using production plans as our data foundation is that participation in most balancing markets is not included in the data. This reduces the potential bias from participation in other markets.

Transmission capacity abroad was significantly increased in the summer of 2021 when new cables to UK and Germany came into operation. This happened during the period of our analysis but is not explicitly accounted for. One possible implication of this is that the variable estimates of European variables, such as the carbon price, and especially the gas prices might not have the correct specification as the variables' effect might have changes through the period in question.

Other policies can also have affected the production of hydropower without having been accounted for in the analysis. The resource rent taxes, power price subsidies and grid tariffs have all been changed through the period in question. However, one might expect that parts of the effects of the resource rent tax will be omitted by investigating the production itself, and not investments. Also, it is reasonable to expect that parts of the variation by power price subsidies and grid tariffs will be reflected in the partial effect of the current- and future electricity price.

Lastly, hydropower optimization can be affected by other restraints than those considered in the model. There might be environmental considerations that affects the maximum and minimum levels allowed for production, production can be restricted due to its position along a riverbed, or the area transmission capacity can be restrained.

9.4. The Question at Hand

One of the key questions regarded in the work of the thesis is what time-aspect that is of interest to investigate when it comes to the HPC. This thesis chose to investigate the distribution between hours in the day to provide information on the power-balance. This can be relevant to system operators' routines for handling these kinds of production policies. However, several other time-aspects might be interesting to investigate. It could be interesting to take an event study approach for the introduction of the HPC – looking at the power market effects in the first days, weeks and months following the introduction of the HPC. This has not been the focus in this analysis. Another aspect is more directly investigating the production in the high-price hours themselves, or the few hours of the year with the largest demand.

10. Conclusion

Challenges in the power balance (Norwegian: effektbalanse) occur during peak load hours in the morning (07-11) and in the afternoon (17-19) during the coldest winter days (Thema Consulting, 2022). Hydropower offers significant flexibility in adapting to electricity market conditions such as the power balance, but the introduction of the Norwegian high-price contribution (Norwegian: høyprisbidraget), or HPC for short, potentially complicates this flexibility.

The HPC is a 23% tax[13] on the portion of the spot price above 0.7 NOK/kWh. The tax took effect for large hydropower producers on the same day it was announced, 28th September 2022. By being levied on only high-price hours, the tax reduces the relative profitability of producing during these hours. The theory section showed that given the uncertainty of future prices, this could change the allocation of hydropower production over time. Following from this the thesis answers the two research questions (RQ): 1: How does the Norwegian high price contribution affect the allocation of reservoir hydropower production throughout the day? 2: Is the effect from RQ1 dependent on the general price level in different bidding areas?

To answer the research questions, the thesis takes an empirical approach, using data from several sources to answer the research questions. Data on planned hydropower production, maximum installed capacity and day-ahead electricity prices is retrieved from the Norwegian Energy Regulatory Authority, futures electricity prices and Euroepan gas- and carbon prices. Also, weather data on reservoir filling and temperature data is retrieved from the Norwegian Water Resources and Energy Directorate and the Norwegian Meteorological Institute (MET) respectively. The study obtains estimates on hourly production using a standard Tobit model, with interaction terms hourly dummies and the HPC. The methodology has some drawbacks in that it does not account for serial correlation and there might be a presence of omitted variables.

Descriptive statistics on the first RQ shows that the average production for the different hours is flatter after the HPC took effect, than before it was introduced. That is, production plans during night-time (21 -06) hours are on average higher than before HPC was introduced, and the opposite is true for day-time hours. Looking closer at the same question with statistical methods the same trend for the daytime hours is found, while the result is inconclusive for night-time hours. The results indicate that there is a statistically significant lower hourly allocation after the HPC came into effect for daytime-hours, compared to before it was introduced.

On the second RQ the answer is not as clear-cut. Here, a similar trend as the results from the first RQ for the bidding areas of NO1, NO2, and a similar result for NO5 can be seen. For NO3 and NO4, the two most northern areas, the model is inconclusive. The results indicate that the effect of the HPC on hourly allocation of production do depend on the general price level. NO1, NO2 and partly NO5, all high-price bidding areas, shows a significant reaction in hourly allocation during day-time hours similar to that of the overall results. The results for NO3 and NO4, the northern low-price bidding areas, is inconclusive.

The tax differentiates between hours bellow and above the 0,7 NOK/kWh threshold. As this thesis argue this is the attribute of the tax that gives the change in allocation of production over time. One policy implication of this is that setting an equal tax rate for all prices would not lead to the harmful allocation of production implied by the thesis results. Such a tax design would affect the expected marginal revenue for the whole range of probable prices, thereby forgoing the allocational responses to the tax seen here. Also note that the tax's' monotonic characteristics reduces these harmful effects.

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[13] Excise duty (Norwegian: særavgift)

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Appendix: Standard Tobit Model Assumptions

This appendix explains the model assumptions for the standard Tobit model used in this thesis, and how these are tested for. Also, results on these tests are presented. Wooldridge states the model assumptions of the standard Tobit model (2019, s. 572). That is, the latent variable, in our case, $ProdPlan^*$, must satisfy the classical linear model assumptions. In particular, the assumptions of normal distribution and homoscedastic errors are of especial importance. The consequence of breaking these last assumptions is explained in Wooldridge (2010, s. 533). The first four assumptions are discussed for the full dataset at these are connected to the dataset itself, while the last two assumptions are discussed for each model obtained for the second research question as well.

Linear in the Parameters

The assumption of a linear model states that there must be a linear relationship between the independent variables and the underlying latent variable. The assumption is examined using scatterplots between the underlying latent variable and the different independent variables. These plots are not displayed here out of space considerations. However, with many observations the assumption is difficult to assess and data show congestions of observations at different production levels, which again underlines the coefficient of the lagged dependent variable and a presence of unobserved effects.

Transmission capacity abroad was significantly increased in the summer of 2021 when new cables to UK and Germany came into operation. This happened during the period of our analysis but is not explicitly accounted for. One possible implication of this is that the variable estimates of European variables, such as the carbon price, and especially the gas prices might not have the correct specification as the variables' effect might have changes through the period in question.

To obtain a clearer linear relationship some variables were log-transformed. However, the lagged electricity variable was not log-transformed due to it containing negative and null-values. In retrospect this could have been adjusted for by replacing null-values with a small constant.

Random Sampling

This assumption requires that the data utilised in the thesis is obtained by random sampling from the cross sections. A potential threat to the criteria is that there is a selection bias in how cross-sections are obtained. The dataset utilised in this thesis is the full population of station groups, with some exceptions: Out of privacy concerns, station groups with total installed capacity lower than 50 MW are excluded from the dataset. Second, only station group including power production from other hydropower types than reservoir power is included. This can result in station groups consisting of other types of hydropower production being excluded from the dataset, possibly resulting in non-random sampling. Third, only station groups where all plants with rated power output (Norwegian: påstemplet merkeytelse) of 10,000 kVA or more is included in the dataset. Lastly, the dataset used in the thesis shows only the balance responsible parties and station groups that have not had changes in their organisation in the period 2021-01-01 to 2023-12-31. In total, these filtrations can lead to non-random sampling of the population Especially, station groups consisting of smaller plants, and smaller station groups, tend to fall out of the dataset. These were necessary adjustments to attain access to data in this thesis but can result in non-random sampling.

No Perfect Collinearity

Perfect collinearity, also known as perfect multicollinearity, occurs when two or more independent variables in a regression model are perfectly correlated. This means that one independent variable can be expressed as a perfect linear function of the others. Breaking the assumption can result in problems separating the effects of the perfectly multicollinear variables.

The assumption can be tested a correlation table of the included variables. Here all “other variables” are included, while hourly, interaction and monthly dummies are not included out of interpretability. However, when including these dummies, it can be observed some correlation between monthly dummies and the weather variables reservoir filling and temperature, a result that is in line with discussion in section on “Hydropower as a source of electricity”.

Observe that no correlation is above 0,8 meaning that perfect multicollinearity is not an issue in our model. However, do assess high correlation between the following sets of variables carbon price and gas price, lagged production plans and installed capacity (MaxEffect_MW), gas price and future electricity price, and lastly production plans and lagged production. The correlation table does not show signs of perfect multicollinearity. Also, their low p-values in the regression results in Table 8-2 indicating that they have sufficiently distinct effects on production plans.

	ProductionPlan	MaxEffect_MW	ln_filling	ln_2pos_NORD	Temperature	ln_P_Gas_NL	ln_P_Carbon	HPC_bin	ProductionPlan_lag	EUR_MW
ProductionPlan	1.000000	0.543334	0.087624	0.024349	-0.187989	-0.052090	-0.054753	-0.009109	0.671834	0.014701
MaxEffect_MW	0.543334	1.000000	0.006814	0.003528	0.032674	-0.000621	-0.001278	-0.002531	0.759850	0.127288
ln_filling	0.087624	0.006814	1.000000	0.120788	0.068534	-0.008486	-0.143122	0.038136	-0.010078	-0.150389
ln_2pos_NORD	0.024349	0.003528	0.120788	1.000000	-0.132631	0.675649	0.468964	0.041567	-0.073866	0.451810
Temperature	-0.187989	0.032674	0.068534	-0.132631	1.000000	0.118400	0.148140	-0.008466	-0.200268	0.040672
ln_P_Gas_NL	-0.052090	-0.000621	-0.008486	0.675649	0.118400	1.000000	0.774341	0.534519	-0.118322	0.295423
ln_P_Carbon	-0.054753	-0.001278	-0.143122	0.468964	0.148140	0.774341	1.000000	0.497702	-0.126179	0.185260
HPC_bin	-0.009109	-0.002531	0.038136	0.041567	-0.008466	0.534519	0.497702	1.000000	-0.047720	-0.057765
ProductionPlan_lag	0.671834	0.759850	-0.010078	-0.073866	-0.200268	-0.118322	-0.126179	-0.047720	1.000000	-0.059606
EUR_MW	0.014701	0.127288	-0.150389	0.451810	0.040672	0.295423	0.185260	-0.057765	-0.059606	1.000000

Table 0-1. Correlation table of selected variables.

No Omitted Variable Bias

The assumption of no omitted variables, also called the zero conditional mean assumption, imply that the independent variables included in the model are exogenous. That is, they are not correlated with the error term in the same model. When this is not the case, one can have a presence of Omitted Variable Bias (OVB).

OVB can be due to several reasons, but in our case, this analysis likely has unobserved effects tied to the station group that are not accounted for in the analysis. Station group-specific variables are not possible to match with the data as it is anonymized. This is because the thesis obtains panel data, but our standard Tobit model treats all observations as one long cross-sectional dataset. This leads to dependence in the distribution of production plans for different time-periods.

It is also possible that OVB is present by not including all variables that affect production decisions, e.g. current gas price and gas storage as mentioned in the section above. As stated in the section on “Futures European Gas Price” the day-ahead gas price might also be of importance in estimating the expected current electricity price, but it was not included because of a high expected correlation between the futures gas price and the day-ahead gas price. This might cause omitted variable bias (OVB) in our estimation. One possible solution to this would be to include the current gas price and rather include European gas storage as (Løfgren & Ingstad, 2023).

Also, OVB can result from one of the included variables only partly explaining the variation from a relevant factor. Temperature for example is a proxy for the demand of electricity, but temperature alone cannot explain all variation in demand. To account for differences in peoples' habits and changing business cycles through the year hourly and monthly dummies were added to catch some of this variation. Also, different functional forms of temperature were tested to account for very cold temperatures to have a stronger effect on demand than the temperatures not as extreme. However, these did not show improvement to model accuracy on test-data. Seasonal interaction terms were not tested, which could have been a possible improvement of the model specification. Second, the thesis obtains data on the bidding area reservoir filling level, not on the reservoir level for each station group. This might result in the full effect of the reservoir level not being controlled for, resulting in OVB. A related, but not the same issue is that of possible simultaneous causality of reservoir filling as it depends on the previous production. However, the reservoir filling which is included is lagged by five days. Meaning that the production plan today cannot affect past reservoir filling levels. Because of the lagging, the analysis do not consider simultaneous causality bias to be a problem in connection with the reservoir filling.

Homoscedasticity

Homoscedasticity implies that the variance of the error terms is constant across different levels of the predictor variables. The assumption can be examined using scatter plots of the residuals against the predicted values (here, $ProdPlan^{*}$), as shown in

Heteroscedasticity plots are similar for the results of the five bidding areas and are therefore not included.

Figure 0-1. The results show a clear pattern in the predicted vs residuals. Heteroscedasticity is tested using a Breusch-Pagan test. The null hypothesis is rejected and find a presence of heteroscedasticity. From the figure observe a clear decreasing pattern. The results indicate that our variance should be cautious of the standard errors, and hence the p-values of our regression results.

Heteroscedasticity plots are similar for the results of the five bidding areas and are therefore not included.

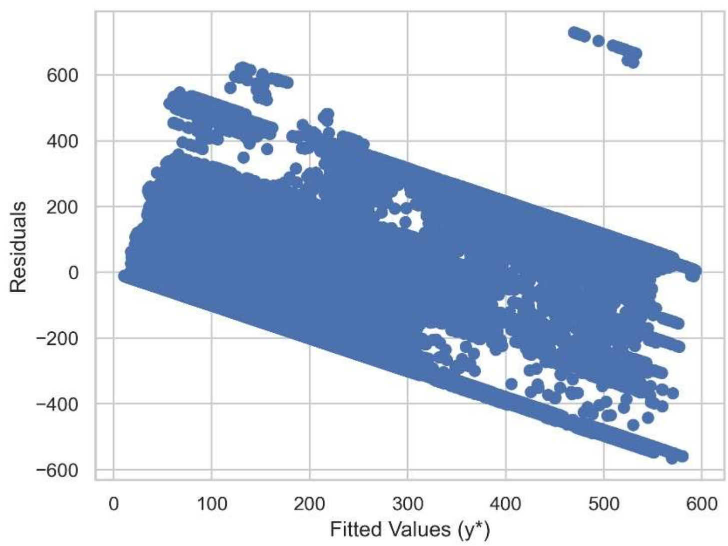

Figure 0-1. Scatterplot of residuals against fitted values, both of the latent underlying variable, $ProdPlan^{*}$. RQ1 model.

Normally Distributed Errors

The Tobit model, rely heavily on the latent underlying variable being normally distributed and independently and identically distributed (IID). The normality assumption can be examined plotting the residuals of the latent underlying variable ($ProdpLan^{*}$) and a quantile-quantile (Q-Q) plot. The results are shown in Figure 0-2. From the right panel very volatile Q-Q plots can be observed. Hence, the latent underlying variable is far from being normally distributed. However, from the left pane observe that the latent underlying variable is approximately symmetric around zero. The results indicate that our errors are not identical distributed, possibly resulting in biased estimates.

QQ plots are similar to the RQ1 model for all RQ2 models. Also, the residual histogram is similar to the RQ model for both NO1, NO4 and NO5. Residual histograms for NO2 (left) and NO3 (right) are displayed in Figure 0-3. Observe that the distributions are even less normally distributed than the other models.

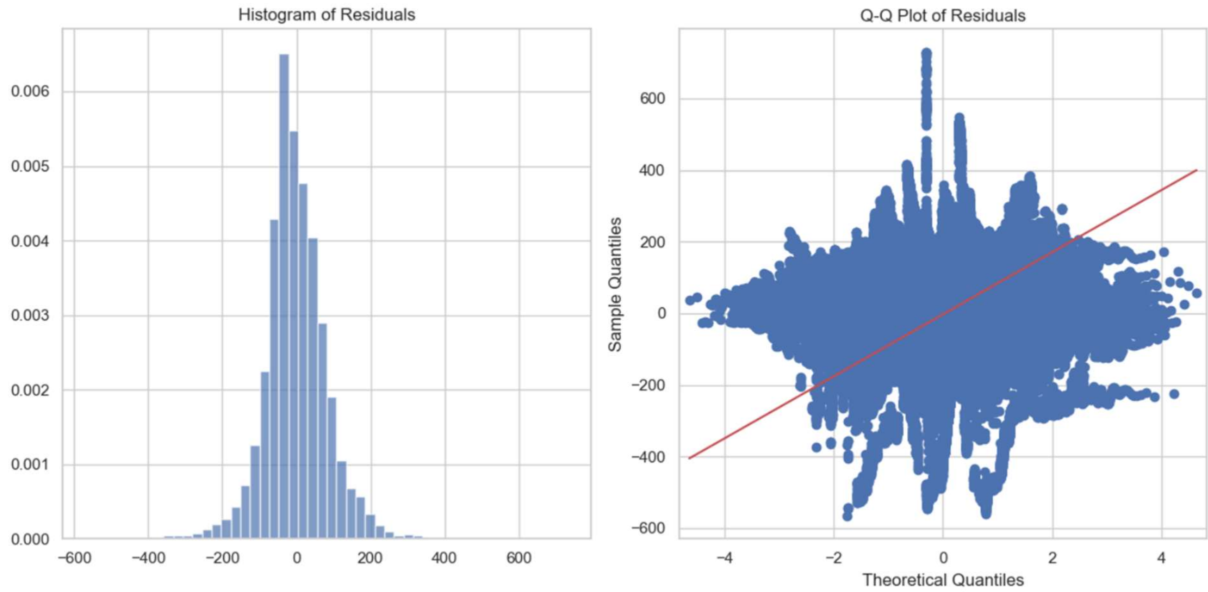

Figure 0-2. Left: histogram of residuals of the latent underlying variable ($\mathbf{ProdPlan}^{*}$). Right: QQ plot of residuals. RQ1 model.

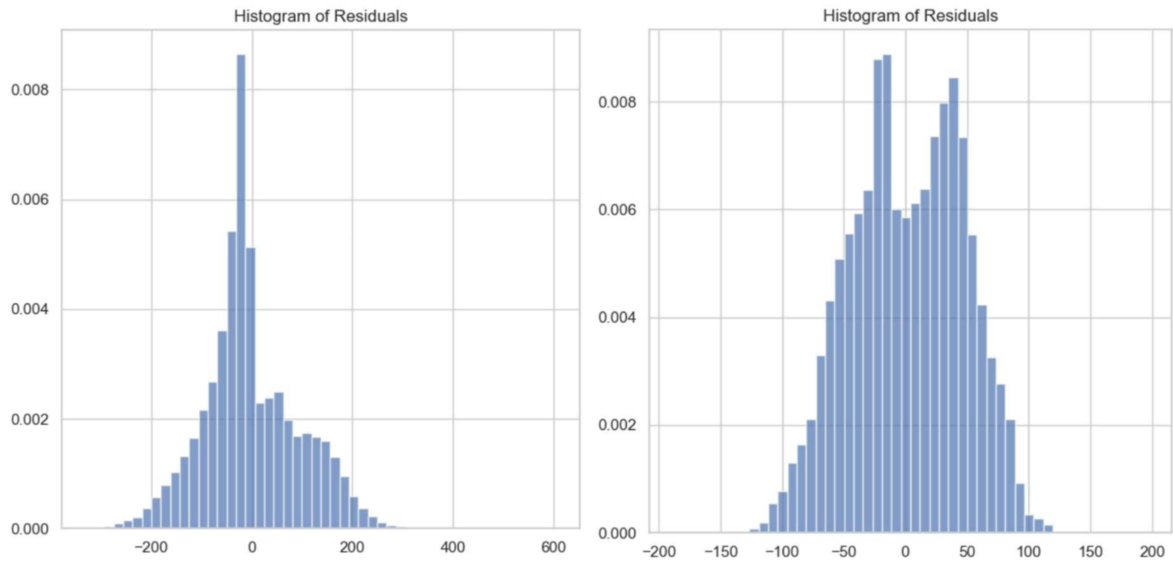

Figure 0-3. histogram of residuals of the latent underlying variable ($\mathbf{ProdPlan}^{*}$). Left: NO2 model. Right: NO3 model.

Appendix: Model Results of Research Question 2

This appendix displays the model results for the second research question. Look to the section on "Partial Effects" for interpretation of model results.

Monthly dummies

Variable name	PE NO1	p-val NO1	PE NO2	p-val NO2	PE NO3	p-val NO3	PE NO4	p-val NO4	PE NO5	p-val NO5
m2	2.36	0.161	-18.38	0.000	-0.15	0.804	6.60	0.000	-4.80	0.001
m3	31.18	0.000	-8.82	0.000	14.74	0.000	-5.79	0.000	-25.18	0.000
m4	-4.05	0.213	-8.51	0.000	17.52	0.000	35.57	0.000	-20.90	0.000
m5	12.64	0.000	-18.41	0.000	26.79	0.000	10.98	0.000	11.35	0.000
m6	-2.25	0.401	24.71	0.000	11.37	0.000	-3.83	0.014	14.85	0.000
m7	-6.71	0.012	16.93	0.000	33.53	0.000	13.08	0.000	-36.43	0.000
m8	-0.43	0.868	22.93	0.000	23.73	0.000	6.84	0.000	-33.28	0.000
m9	-27.19	0.000	6.23	0.000	3.61	0.000	15.46	0.000	-63.52	0.000
m10	-3.71	0.110	40.24	0.000	2.09	0.003	-21.57	0.000	-37.40	0.000
m11	25.57	0.000	44.56	0.000	3.97	0.000	-12.91	0.000	-35.33	0.000
m12	-0.44	0.818	-9.91	0.000	-6.06	0.000	-10.69	0.000	-29.68	0.000

Table 0-1. Variable estimates for monthly dummies from the standard left censored Tobit model described in section 7.1., split on each bidding area.

Hourly dummies

Variable name	PE NO1	p-val NO1	PE NO2	p-val NO2	PE NO3	p-val NO3	PE NO4	p-val NO4	PE NO5	p-val NO5
h1	-8.89	0.003	-6.01	0.004	-1.36	0.180	-3.43	0.088	-7.47	0.003
h2	-14.06	0.000	-9.29	0.000	-2.25	0.027	-4.79	0.017	-11.45	0.000
h3	-14.91	0.000	-11.30	0.000	-2.48	0.015	-4.77	0.017	-13.88	0.000
h4	-12.49	0.000	-10.52	0.000	-1.81	0.074	-2.54	0.205	-12.53	0.000
h5	-0.36	0.902	-3.18	0.129	-0.17	0.867	2.13	0.288	-5.86	0.018
h6	25.48	0.000	19.56	0.000	3.52	0.000	6.97	0.001	5.41	0.029
h7	48.72	0.000	38.11	0.000	8.19	0.000	12.74	0.000	20.03	0.000
h8	59.59	0.000	44.25	0.000	10.57	0.000	15.59	0.000	23.53	0.000
h9	60.70	0.000	47.32	0.000	11.67	0.000	18.22	0.000	23.14	0.000
h10	57.25	0.000	48.07	0.000	12.79	0.000	19.13	0.000	20.11	0.000
h11	52.13	0.000	46.25	0.000	13.35	0.000	19.84	0.000	15.80	0.000
h12	46.79	0.000	43.34	0.000	13.32	0.000	19.18	0.000	11.99	0.000
h13	41.66	0.000	41.10	0.000	13.05	0.000	17.83	0.000	8.62	0.001
h14	40.27	0.000	40.59	0.000	12.95	0.000	17.27	0.000	7.45	0.003
h15	41.67	0.000	42.25	0.000	12.93	0.000	17.03	0.000	10.72	0.000
h16	49.31	0.000	45.86	0.000	13.19	0.000	17.16	0.000	15.39	0.000
h17	58.87	0.000	52.85	0.000	13.52	0.000	18.98	0.000	22.95	0.000
h18	64.71	0.000	56.29	0.000	13.51	0.000	19.86	0.000	28.06	0.000
h19	64.40	0.000	55.21	0.000	12.82	0.000	19.48	0.000	29.57	0.000
h20	57.68	0.000	48.34	0.000	11.31	0.000	17.85	0.000	25.34	0.000
h21	48.79	0.000	40.40	0.000	9.06	0.000	15.69	0.000	18.97	0.000
h22	35.09	0.000	31.06	0.000	6.54	0.000	12.43	0.000	16.19	0.000
h23	18.89	0.000	20.27	0.000	3.30	0.001	6.51	0.001	5.98	0.016

Table 0-2. Variable estimates for hourly dummies from the standard left censored Tobit model described in section 7.1., split on each bidding area.

Interaction dummies

Variable name	PE NO1	p-val NO1	PE NO2	p-val NO2	PE NO3	p-val NO3	PE NO4	p-val NO4	PE NO5	p-val NO5
h1xHPC	2.32	0.618	-1.12	0.736	-2.62	0.119	-1.38	0.676	2.28	0.576
h2xHPC	3.67	0.432	-2.08	0.533	-2.46	0.143	-2.01	0.544	4.12	0.312
h3xHPC	2.44	0.601	-3.01	0.366	-2.52	0.132	-2.87	0.386	5.13	0.208
h4xHPC	0.49	0.917	-4.34	0.193	-2.84	0.090	-3.44	0.299	3.46	0.395
h5xHPC	-5.15	0.266	-6.20	0.062	-0.24	0.887	-1.44	0.663	0.47	0.908
h6xHPC	-17.96	0.000	-16.13	0.000	-0.00	0.998	0.83	0.802	-3.91	0.336
h7xHPC	-30.67	0.000	-23.10	0.000	-0.27	0.871	2.53	0.442	-8.87	0.029
h8xHPC	-40.21	0.000	-25.42	0.000	-0.24	0.887	4.88	0.139	-9.13	0.025
h9xHPC	-42.08	0.000	-28.03	0.000	-0.77	0.643	4.22	0.201	-9.52	0.019
h10xHPC	-39.89	0.000	-32.64	0.000	-1.67	0.314	2.99	0.364	-8.70	0.033
h11xHPC	-40.47	0.000	-36.70	0.000	-2.11	0.204	1.53	0.642	-6.46	0.112
h12xHPC	-40.48	0.000	-36.68	0.000	-2.69	0.106	1.28	0.698	-5.98	0.142
h13xHPC	-37.53	0.000	-36.36	0.000	-3.12	0.061	0.86	0.794	-5.10	0.210
h14xHPC	-36.09	0.000	-35.36	0.000	-3.12	0.061	0.01	0.999	-4.00	0.326
h15xHPC	-33.86	0.000	-34.47	0.000	-2.42	0.147	2.29	0.487	-3.27	0.422
h16xHPC	-32.71	0.000	-32.26	0.000	-1.44	0.386	4.75	0.150	-2.14	0.599
h17xHPC	-34.06	0.000	-28.57	0.000	-1.07	0.522	5.20	0.115	-4.01	0.324
h18xHPC	-36.19	0.000	-24.66	0.000	-1.03	0.537	4.85	0.142	-6.18	0.129
h19xHPC	-35.76	0.000	-21.76	0.000	-1.60	0.336	3.90	0.237	-8.58	0.035
h20xHPC	-32.31	0.000	-17.73	0.000	-1.66	0.318	2.82	0.392	-8.10	0.047
h21xHPC	-28.74	0.000	-14.58	0.000	-0.54	0.745	2.30	0.485	-7.00	0.085
h22xHPC	-20.96	0.000	-11.31	0.001	-0.34	0.836	1.20	0.716	-7.64	0.061
h23xHPC	-11.64	0.011	-8.33	0.011	-0.43	0.795	-0.10	0.976	-3.13	0.442

Table 0-3. Variable estimates for hourly interaction dummies from the standard left censored Tobit model described in section 7.1., split on each bidding area.

Other variables

Variable name	Partial Effects NO1	p-values NO1	Partial Effects NO2	p-values NO2	Partial Effects NO3	p-values NO3	Partial Effects NO4	p-values NO4	Partial Effects NO5	p-values NO5
Intercept	-57.31	0.000	-246.80	0.000	-143.05	0.000	-120.95	0.000	-101.11	0.000
Installed Capacity	0.20	0.000	0.14	0.000	0.28	0.000	0.05	0.000	0.15	0.000
ln(filling)	54.39	0.000	14.17	0.000	34.70	0.000	59.55	0.000	48.15	0.000
ln(Fut El Price)	-26.15	0.000	-34.08	0.000	-11.08	0.000	43.18	0.000	4.94	0.000
Temperature	-1.74	0.000	-5.60	0.000	-1.25	0.000	-2.39	0.000	-1.10	0.000
ln(Gas Price)	-25.77	0.000	-30.97	0.000	-3.69	0.000	-24.64	0.000	-15.68	0.000
ln(Carbon Price)	45.37	0.000	87.99	0.000	40.94	0.000	4.99	0.013	49.48	0.000
HPC	77.22	0.000	68.76	0.000	-5.16	0.000	12.62	0.000	6.30	0.059
lag(Prod Plan)	0.76	0.000	1.13	0.000	0.81	0.000	0.85	0.000	0.48	0.000
El Price	0.15	0.000	0.26	0.000	0.21	0.000	0.34	0.000	0.06	0.000

Table 0-4. Estimation results for continuous variables from the standard left censored Tobit model described in section 7.1, split on each bidding area.

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