Master's thesis

NTNU
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NTNU Business School

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A Scenario Analysis of the NO1 Electricity Price

Exploring profit drivers for a run-of-river electricity producer using SARIMAX.

Master's thesis in Master in Economics and Business Administration
Supervisor: Johannes Mauritzen
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Preface

This master´s thesis is written as a final part of the program Master of Science and Business Administration at NTNU, the Norwegian University of Science and Technology. The authors have written across two main profiles: finance and business analytics, with a particular emphasis on the latter throughout our writing of the thesis.

We would like to thank our supervisor, Johannes Mauritzen, for his guidance and support throughout the research process. Additionally, we extend our thanks to Nord Pool and Akershus Energi for granting us access to their data, which has been instrumental in conducting our analysis.

We wanted to focus on the Norwegian electricity market, as there is an ongoing public debate on this topic, and it is of interest. We found the topic of electricity to be challenging and complex, but highly rewarding when delved into.

The content of this master's thesis is the sole responsibility of the authors.

Sammendrag

Målet med denne masteroppgaven er å undersøke effekten av økt overføringskapasitet, høye naturgasspriser og lokale værvariabler (temperatur og nedbør) både på spotprisen for det norske budområdet NO1 og lønnsomheten til en representativ elvekraftprodusent, Glomma Kraftproduksjon AS (GKP) innenfor dette budområdet. For å besvare oppgaven ble det gjennomført en scenarioanalyse ved hjelp av en sesongbasert autoregressiv integrert glidende gjennomsnittsmodell med eksogene variabler (SARIMAX). Metoden involverte å konstruere en baseline-modell gjennom en prosess som inkluderte blant annet variabelvalg og parameterestimering, etterfulgt av scenarioer basert på oppgavens forskningsspørsmål.

For å vurdere effekten på lønnsomheten til GKP, ble siste kvartal av 2022 valgt for videre analyse. Det ble imidlertid observert at modellen hadde problemer med å fange opp den høye volatiliteten i datasettet for den perioden. Som en løsning på dette fokuserte evalueringen av modellen på hvor godt den fanget opp gjennomsnittlig spotpris over en tre-måneders periode, i stedet for å se på daglige svingninger.

Resultatene fra scenarioanalysen viste at økt importkapasitet gjennom NordLink- og North Sea Link kablene var den eneste eksogene variabelen med betydelig innvirkning på NO1-spotprisen, og dermed på lønnsomheten til GKP.

En tredobling av naturgassprisen i vårt andre scenario viste ingen tydelig innvirkning på NO1 spotprisen. For det tredje scenariet ble værvariablene temperatur og nedbør undersøkt. Vi så på to forskjellige scenarioer: "svært tørt og svært kaldt" og "svært vått og svært varmt". Imidlertid ble det ikke funnet noen korrelasjon mellom elektrisitetsprisen og disse værvariablene. Dette tyder på at variasjoner i temperatur og nedbør ikke hadde en betydelig innvirkning på spotprisen i NO1, i hvert fall innenfor rammene av denne studien.

Oppsummert fant studien at lokale værvariabler for NO1 hadde liten eller ingen innvirkning på NO1 spottprisen. Den fant også at importkapasitet hadde en sterk innvirkning på pris, men at naturgassprisene i Europa ikke påvirket NO1-prisen. Avslutningsvis var det interessant å oppdage at GKP har ingen innflytelse over prisen på varen den selger og svært begrenset kontroll over kostnader og dermed lønnsomheten. Imidlertid er vekst i importkapasitet og

økende markedsintegrering med Europa til stor fordel, og medfører et svært lønnsomt scenario for GKP.

Abstract

The aim of this master's thesis is to investigate the impact of additional interconnector capacity, abnormally high natural gas prices, and local weather variables (temperature and precipitation) on both the spot price for the Norwegian bidding zone NO1 and profitability for a representative run-of-river hydropower producer in NO1, Glomma Kraftproduksjon AS (GKP). To answer the thesis, a scenario analysis was conducted with the use of a seasonal autoregressive integrated moving average with exogenous variables model (SARIMAX). The methodology involved the process of creating a baseline model through a feature selection and parameter estimation process, followed by the creation of scenarios based on the thesis's research questions.

In order to assess the impact on profitability for GKP, the last quarter of 2022 was selected for analysis. However, it was observed that the model struggled to capture the high volatility inherent in the dataset during that time period. As a remedy to this, the evaluation of the model focused on how well it captured the average spot price over the three-month period in place of the day-to-day fluctuations.

The results from the scenario analysis showed that an increase in additional import capacity through the NordLink and North Sea Link interconnectors was the only exogenous variable with any significant impact on the NO1 spot price and consequently on the profit generation of GKP.

Increasing the natural gas price by a factor of three for our second scenario found no evident impact on the NO1 Elspot price. For the third scenario, weather variables of temperature and precipitation were examined. We looked at two different scenarios: "dry and cold" and "wet and warm". However, no correlation was found between the electricity price and these weather variables. It suggests that the variations in temperature and precipitation did not have a significant impact on the electricity price in NO1, at least within the scope of this study.

In summary, the study found that local weather variables for NO1 had little to no impact on the NO1 Elspot price. It also found that import interconnector capacity had a strong impact on price, but that natural gas prices in Europe did not show any impact on the NO1 price. Finally, GKP has no influence over the price of the commodity it sells and very limited control over

its cost and, therefore, its profitability. However, interconnector capacity growth and increasing market integration with Europe are of great benefit and, according to this study period, result in a highly profitable scenario outcome for GKP.

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Glossary of terms

ACF	Autocorrelation Function
ADF	Augmented Dickey-Fuller test
AE	Akershus Energi AS
AEV	Akershus Energi Vannkraft AS
ARIMA	Auto-regressive integrated moving average
Bidding Zone	Geographical area to which network constraints are applied
ENTSO-E	European Network of Transmission System Operators for Electricity
GKP	Glomma Kraftproduksjon AS
HVDC	High-voltage direct current
MC	Market Coupling (MC) refers to the integration of different energy markets into one coupled market.
MCO	Market Coupling Operator
MET	Norwegian Meteorological Institute
MLR	Multiple Linear Regression
MPE	Ministry of Petroleum and Energy
NEMO	Nominated Electricity Market Operator
NO1	Norwegian bidding zone NO1 (“Eastern Norway”)
Nord Pool	A Nominated Electricity Market Operator in 16 European countries, offering trading, clearing and settlement services in day ahead and intraday markets.
NordLink	Nordlink, the interconnector between Germany and Norway
NOU	Norway’s Commission of Enquiry
NSL	North Sea Link, the interconnector between the UK and Norway
NVE	The Norwegian Water Resources and Energy Directorate
PACF	Partial Autocorrelation Function
PCR	Price Coupling of Regions
PCR Euphemia	Pan-European Hybrid Market integration Algorithm.
SARIMAX	Seasonal Auto-regressive integrated moving average with exogenous variables
TSO	Transmission System Operator

1 Introduction

In recent times Norwegians have experienced extraordinarily high electricity prices that have never been seen before in its history. This power price shock comes coincidentally and rather unfortunately at a time of global inflationary pressures that are placing many households and businesses into financial stress. At the same time power producers are enjoying windfall profits. In Norway 90% of all power generation capacity are connected to state ownership either through a Municipality, County, or the State. (Ministry of Petroleum and Energy [MPE], 2016a). There has been a view in public debate that power companies and the Norwegian state actors (the power generator asset owners) even after the cost of subsidies, have been benefiting from high prices, taxation, VAT, and dividends it receives from state-owned companies (Skårdalsmo & Skei, 2022). This is seen to be causing hardship among the households and businesses whose profitability are highly sensitive to power costs (Kalajdzic et al., 2022).

For the government and the political opposition parties, this has been a ‘hot’ issue. The Norwegian government recognised the problem and intervened with price subsidies. However, measures such as this are not sustainable solutions because they may exacerbate the problem, by for example, increasing demand and may as well cause cross-border issues that hurt consumers in other countries by raising prices there. We see this in Norway where the consumer surplus appears to have shrunk. Structural answers should therefore be considered (Zettelmeyer et al., 2022). Power producers are also under fire but not all producers have the same degree of control over their profitability. Our thesis will look at a typical run-of-river producer to determine what level of impact prices can have on their profitability.

For many years Norway has relied upon a deregulated electricity market with price mechanisms that are based on the market forces of supply and demand. The development and success of the Norwegian electricity market has been seen as a lighthouse model for other countries deregulating their power sectors. The journey Norway took is set out later in chapter 2, The Nordic electricity market and its development. The Norwegian system and the way it has been structured and integrated with other countries, has navigated previous shocks well, right up to and until prices spiked in 2021. At the time the Norwegian government was compelled to intervene in the market and introduce a price subsidy for power. The Norwegian government even went so far as to publicly prepare to limit the export of power to Europe during a Norwegian dry and hot spell in summer 2022, another potential market intervention in the making (Oliver et al., 2022).

The blame for high price conditions has largely been directed in two areas. First, on the growth in the interconnector cable capacity to Europe (Kekve & Helle, 2022), with the Nord-Link and North Sea link (receiving particular attention because of the coincidental relative timing of their commissioning and the arrival of high prices) and second, the high gas prices in Europe. On the other hand, the Norwegian government has sought to blame both the dry conditions in the period and high natural gas prices (Flem, 2022). This conflict of opinions on causes for high prices and the debate on how the super profits have occurred in power production companies both raised our interest and we determined to address both through our thesis.

The Norwegian power system has been increasingly connected to and integrated with the European power market. Cross border power trade allows externalities, such as the price of power in Europe, to impact price of power in the Norwegian market. One example of this is that when there is growth in the capacity of interconnector cable links to Europe, cross border transmission constraints are reduced, and increased price convergence should occur. However, the issue of the level of this impact from cables appears far from resolved and good arguments have been put forward that support this impact on electricity price by these cables is limited (Døskeland et al., 2022).

While the focus has been on the perceived downside of interconnector capacity growth, the corresponding benefit of the interconnectors should not be overlooked. When Norway has had dry years or cold winters, it has benefited from the ability to import power and makes economic gains with the export power sales when it uses water for generation that would otherwise be spilled (Energifakta-Norge, n.d.). The relationship between the interconnector capacity for import and export and price impact is a key relationship we will investigate in support of our thesis.

Gas prices have reached extraordinary heights also across Europe as a result of sanctions associated with the Russian-Ukrainian war. It is well documented that the marginal cost of

natural gas fired thermal generation is very high (NOU 2023:3, p. 142). Avoiding the use of gas-powered generation with demand reduction or access to cheaper forms of electricity has been a European goal. This also coincides with Europe's national and EU policies of a strong and fast transition to intermittent and expensive renewable wind and solar generation and the early retirement of cheap nuclear and coal generation plants (NOU 2023:3, pp. 33-34).
In this context, Norway's rich reserves of hydropower and its role as an energy battery for intermittent European generation has much value. Norwegian hydropower has one of the lowest marginal costs of power production in Europe.

The largest bidding zone in Norway on a consumption basis is NO1, covering Eastern Norway. We will limit our study to understand what the impact of natural gas, interconnector capacity to Europe and weather variables (like precipitation and temperature) may have on the spot price. We are also interested to understand what and if these specific factors also drive an increase in profitability for a power generator in NO1. We have selected Glomma Kraftproduksjon AS (GKP) a NO1 run-of-river hydropower plant for this purpose as it is a large generation asset within NO1.

Our thesis states that:

In addition to standard weather variables (temperature & precipitation) in the NO1 area, recent increases in interconnect transmission cable capacity (Europe) and abnormally high natural gas prices in Europe have caused higher spot prices in the NO1 market and consequently resulted in higher profit for a representative run-of-river hydropower producer, Glomma Kraftproduksjon AS.

To confirm or reject the thesis we pose the following research questions for investigation:

- What effect would a doubling of the recent additional interconnector capacity of NordLink and North Sea Link between Norway and Europe have on NO1 spot price?
- What effect does benchmark European natural gas price have on NO1 spot price?
- What effect does temperature or precipitation in the NO1 bidding zone have on NO1 spot price?
- Does Glomma Kraftproduksjon AS earn increased profit because any of the factors of temperature and precipitation in the NO1, natural gas prices in Europe or the interconnector capacity to Europe are increased?

To answer the research questions, we conducted a baseline and a scenario analysis with a SARIMAX model. SARIMAX is a commonly used time series model that has been used to forecast values of time series variables. It notably includes seasonal effects and exogenous variables. We would also run a profit function for GKP that would forecast its profitability under certain reasonable assumptions for production and costs.

We determined to use three scenarios to test the effect on spot prices of changing interconnector capacity, natural gas price, and the weather variables of temperature and precipitation on determining GKP profit.

Our results show that interconnector import capacity between Southern Norway to Europe has an impact on the NO1 spot price and profit of GKP. As an average over the 3-month model period, the spot price increased by 36% when the interconnector import capacity was increased by a factor of two, while the GKP profit increased by 38%. Our results for modelling natural gas as the exogenous variable were non-explanatory and led to no result. Local weather variables for the NO1 bidding zone had little to no effect as exogenous variables for the NO1 spot price, leading to the conclusion that neither price nor GKP profit would be affected by local weather variables.

2 Background – The Nordic electricity market and its development

2.1 The Nordic Power System – before reform

Prior to reform Norway's market organised a varying mix of generation, transmission, and distribution elements most often as vertically integrated monopolies with obligations primarily to their allocated areas. All investments in both production and transmission capacity were subject to cost reimbursement either through public contributions through a capital subsidy and, or softer mechanisms and this led to over-investment and an under-utilized generation infrastructure. Barely ten percent of contracts were short-term, and the 90% share of long-term contracts were typically bilateral and bespoke, with no common standard form. Market flexibility and liquidity was limited as no secondary market for financial derivatives trading existed, and there was no integration of the market in terms of physical and financial trading. (Bye & Hope, 2005, p. 5269).

The electricity price did not reflect seasonality, weather, or business activity but was set by the regulator and closely linked to short term production costs, a feature that would not encourage cost control in the industry (Huurman et al., 2012, p. 3793). Large differences between prices set by the government and municipalities for the services industry and households on the one hand and segments of industry that were energy intensive on the other was seen as a discriminatory practice that also reduced social welfare (Bye & Hope, 2005, p. 5270).

In the 1980's and 1990's there was an increased dissatisfaction with the existing regulated market and its inefficiencies. Bye and Hope summarised; "The main motivation for electricity market reform was an increasing dissatisfaction with the performance of the sector in terms of economic efficiency in resource utilisation, particularly with regard to investment behaviour, which caused capacity to exceed demand considerably" (Bye & Hope, 2005, p. 5269).

2.2 Important reforms that were made

In answer to the challenges mentioned, in 1991 The Norwegian Energy Act of 1990 was passed. This was and remains a key piece of legislation that laid the foundation for deregulating and liberalising Norway`s power sector (MPE, 2016b). The government relatively quickly progressed the transition. All three foundational components of the electricity market, the trading mechanisms, the transmission tariffs, and the regulatory framework, were reformed to create as competitive a functioning and reliable marketplace as possible. (Mork, 2001, pp. 8-9).

Reform structured the transition such that the electricity market was essentially open to all customers participation from the outset (Energifakta-Norge, n.d.) and also implemented transparent and non-discriminatory access to the transmission system (Bye & Hope, 2005, p. 5271). On the regulatory side, the unbundling of power generation, transmission and distribution was considered essential. "The market liberalisation reform was implemented without changes in ownership for power generation assets. This contrasted for example with the UK, where privatisation was implemented before market liberalisation" (Bye & Hope, 2005, p. 5271). Because of its political unacceptability, the privatization of state-owned assets never occurred (Bye & Hope, 2005, p. 5271).

The transfer of all transmission assets from the vertically integrated power companies was to Statnett, a 100% owned state company. All third parties were given an assured access to network infrastructure. Statnett was awarded responsibility as the national transmission system operator (TSO) where in this role it runs balancing the market as one of its functions. Norway's end-user market consists of about one-third industry, one-third medium-sized consumers such as affiliated and conglomerate businesses like hotel and retail chains and one-third household customers. Post reform, in this end-user market the end-users can now choose their supplier of choice and move relatively freely and without penalty between them. The market for power was divided into wholesale and end-user markets. The wholesale market, which involves large volumes of power is now traded through brokers, power suppliers, energy companies and large industrial consumers. Day-ahead and intra-day trading are organised in the Nord Pool exchange. Market participants can also contract bilaterally for the sale and purchase of defined volumes of power at a fixed price and for delivery over an agreed timeframe (Energifakta-Norge, n.d.).

2.3 The implementation of the power exchange

Norway had already begun to introduce market-based power trading in the beginning of the nineties, but well prior to this, in 1971, it had formally established a spot power exchange known as ‘Samkjøringen’, which essentially means ‘power pooling’ (Mork, 2001, pp. 10-11). While the roots of ‘Samkjøringen’ in Norway can be traced all the way back to 1931, in 1991 reforms were introduced that led to the establishment in 1993 of the formal Norwegian power exchange, Statnett Marked AS (Energifakta-Norge, n.d.). This liberalization effort led to the world’s first national power market for short-term power delivery, offering real-time and day-ahead power delivery, and was renamed Nord Pool AS in 1996 when Sweden joined (Huurman et al., 2012, p. 3794). The primary role of the power exchange is to maximise the economic social welfare for the market and decide which orders were to be executed in such a way as to not exceed the network capacity (NEMO Committee, 2020, p. 5).

To maximise social welfare in a balanced way that recognises a consumer and a supplier surplus required that the reform took place. Strong political support and a collaborative power industry have been keys to its successful development (Amundsen & Bergman, 2006, p. 155).

2.4 Integration with Europe

The significant excess hydropower capacity that existed in Norway prior to reform led to interest in finding export routes to other markets to sell power rather than spill the water. (Bolton, 2022). In order to access new markets, both a physical connection (that is electrically synchronous) and agreements on system function and contracts must also be established. The latter is managed by exchange, collaboration or integration. Synchronicity has been established for all the Nordic exchange members, but Western Denmark and Germany are not synchronized with the Nordic electricity system (Grande et al., 2008, p. 7). As high-voltage direct current (HVDC) transmission technologies became available and bipolar, these interconnector links could reach further with fewer energy losses and allow for transmission in both directions between AC grids that were not synchronized (Hitachi Energy, n.d.). This has resulted in more capacity for both the import and export of power to Europe and a closer integration of the European markets.

A corresponding liberalisation has occurred in Europe over the past two decades with the European Union (EU). Initially, an Electricity Directive in 1996 required member states to open their electricity markets to competition and break up national monopolies (Mork, 2001, p. 8). Later in 2007, a project initiated and led by TSOs and power exchanges resulted in the adaptation of the 'Target Model" to create a fully integrated European electricity market (European Commission, 2017, p. 12). This allows energy transactions across all NEMO regions participating while considering electrical network constraints.

As interconnectivity is expanded, the price coupling of regions and the single price coupling algorithm EUPHEMIA was required to integrate all the power exchange algorithms in one new algorithm that could give pricing solutions in a reasonable time (NEMO Committee, 2020, p. 5). The algorithm EUPHEMIA is executed by the Market Coupling Operator (MCO function). National electricity market operators (NEMOs) are responsible to implement the MCO function. (NEMO Committee, 2020).

2.5 Regulated price setting

Norway ensured from the outset that price mechanisms were regulated with clear rules that were market-based. To establish a mechanism that maximises social welfare, one important mechanism is market-based price setting. At Nord Pool, the member countries are divided into bidding zones, or price areas, by the TSO of the country. In Norway, there are five (5) different price areas, one of which, NO1, is in Eastern Norway (Statnett, 2021a). The run-of-river plant GKP is in the NO1 bidding zone and so it is relevant to the thesis. The areas and transmission capacities between them for Norway (NO1-NO5) and the European market are shown in Figure 1.

Spot price for a bidding zone is set by the Nord Pool electricity exchange in the afternoon using the PCR Euphemia algorithm and for the following day. Spot price is set hourly for the forthcoming 24-hour period in a bidding zone by aggregating purchase and sell orders into demand and supply curves. For each hour the area price and system price are then calculated. (Nord Pool, n.d.)

Figure 1.International connections map (Source: NOU 2023:3)

The system price for the market in consideration is at the intersection of the aggregated supply and demand curves as shown in Figure 2. A system price is not the same as area price. System price is a reference price for the entire market and does not consider capacity constraints but sets this to be unrestrained (Nord Pool, n.d.). It is used as a benchmark for trading in the derivative markets. (Nord Pool, 2020, p. 4). Area price however does consider capacity constraints to avoid overloading transmission lines with excessive power flows

(Nord Pool, n.d.). Area price is calculated through the PCR Euphemia algorithm. The figure 2 below illustrates the price mechanism changes that occur as the system pricing mechanism expanded out of Norway to Europe.

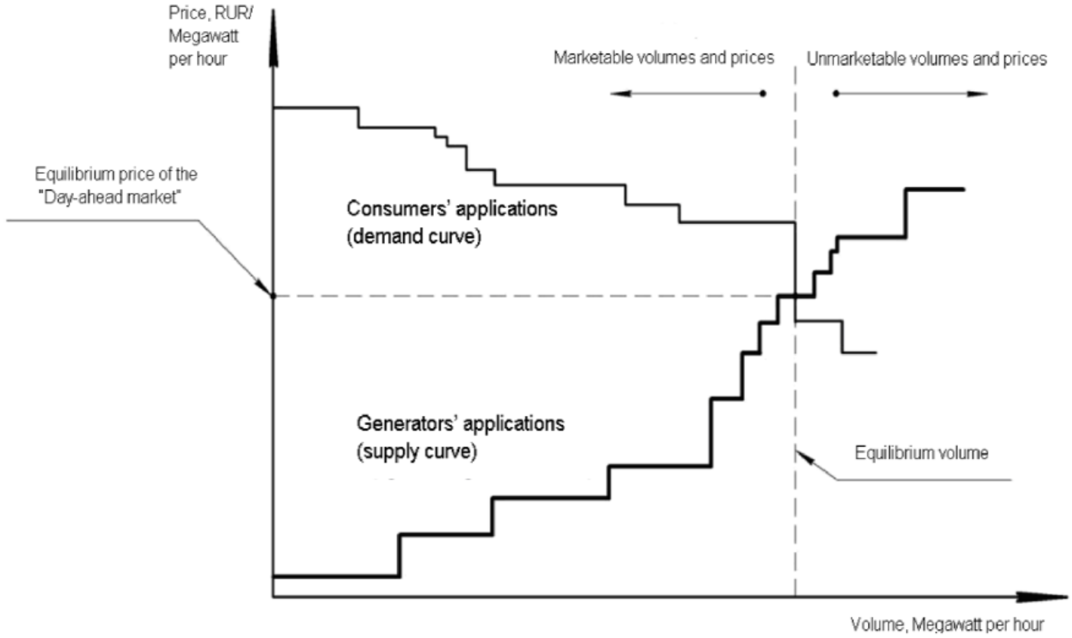


Figure 2. The equilibrium price of the day-ahead market (Source: Моховв & Demyanenko, 2017)

Figure 3 illustrate the potential impact (for summer and winter demand) of market integration with Europe seen in contrast with the Nordic market alone. It shows that when prices in neighbouring countries are higher and supply is constrained, Norway will experience higher prices and so is vulnerable to price shocks in these situations (NOU 2023:3). On the other hand, the reverse will be true if prices are lower in neighbouring countries as happens when renewable wind is abundant and Norwegian demand is high.

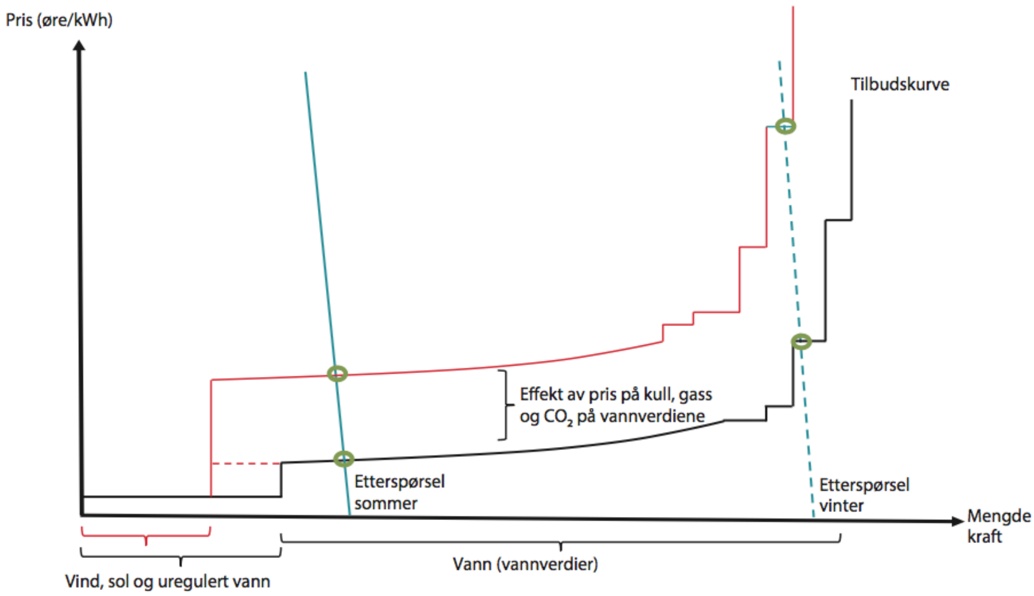


Figure 3. Price setting impact of integration with the Europe. (Source: NOU 2023:3)

Figure 4 below illustrates the merit-order curve that forms the supply curve in Figure 3 for power generation technologies and illustrates that the marginal power plant determines the day ahead price for all the other generators. In section 2.7 GKP, we will look more closely at the impact this approach has on profitability for GKP.

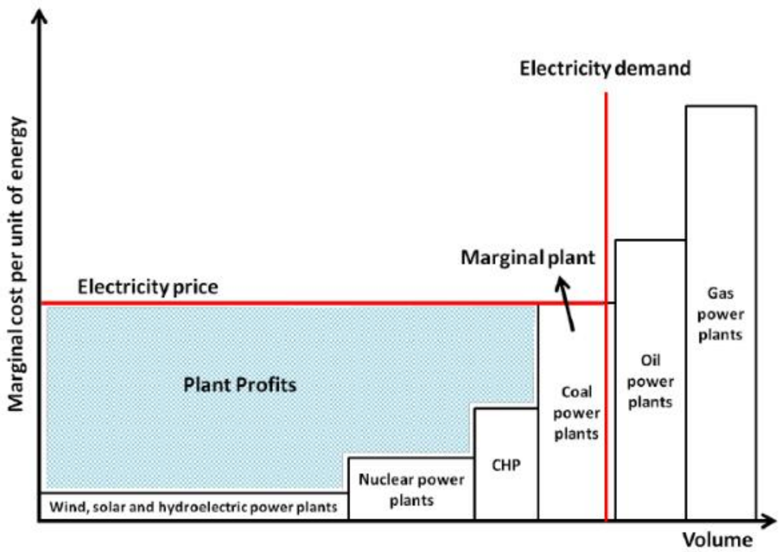


Figure 4. Merit Order dispatch in electricity markets (Source: Sauvage & Bahar, 2013)

2.6 Market intervention

The System was considered to have worked well; even under stress during earlier supply shocks, there were no interventions from authorities or the government until late 2021. Public discourse over the course of electricity market reform has recently been less enthusiastic, causing heated political discussion. In 2021 and 2022, power prices for consumers increased to levels not seen previously (Figure 5). In late 2021, due to enormous political pressure, the Government of Norway approved a power subsidy for households in form of a 50% reduction of the power bill when the spot price rose above 70 øre per kilowatt hour (Regjeringen, 2021). This was later increased to 90% following pressure from the political opposition and was implemented as a deduction on the power bill that the government would pay suppliers (Regjeringen, 2023). It also considered but rejected price controls and restrictions on the export of electricity. Intervention with price subsidies is not a durable and structural adjustment to the system to avoid this in the future, if that indeed is required.

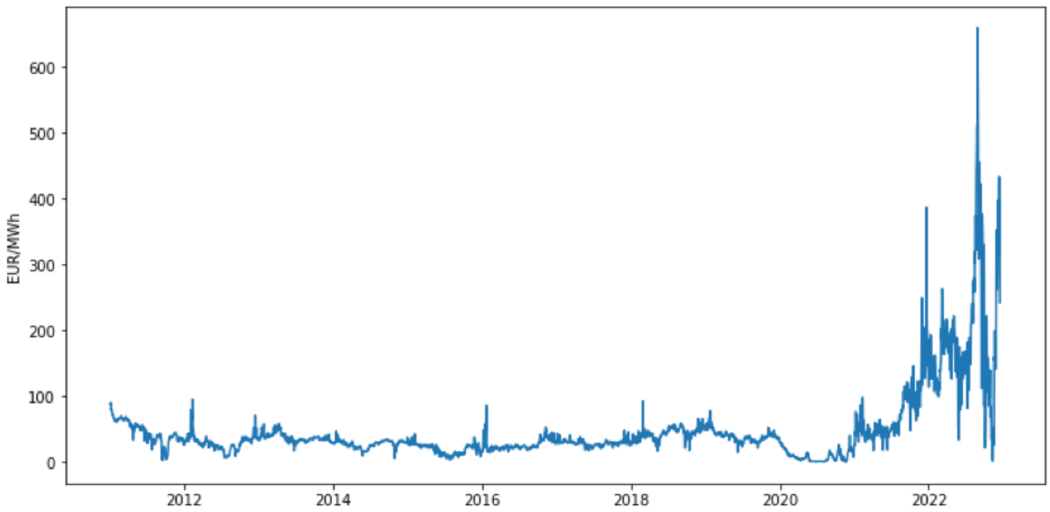


Figure 5. The Development of N01 Elspot price 2011-2022 (Data Source: Nord Pool)

2.7 Glomma Kraftproduksjon AS ("GKP") – Characteristics affecting profitability

The thesis is centered on testing if certain factors in NO1 and externally with interconnection growth that we are observing in the scenarios are generating additional profits for GKP. Earnings Before Interest and Tax (EBIT) is selected to represent profit.

This section gives some background on what the drivers of profit are in theory and specifically for the generation portfolio of GKP. They are price, production volume, fixed costs and variable costs and depreciation.

GKP owns and operates the following power generation assets, all of which are hydropower units of the run-of-river power type.

- Rånåsfoss II/III
- Funnefoss
- Bingfoss
- Bøhnsdalen

The fundamentals of hydropower production are that water, and the potential energy it holds, (provided by gravity and the height of a volume of water falling onto a rotating turbine) is converted through a generator for the production of electricity.

Hydropower is generated in two types of plants; 1) a plant based on unregulated river flows (a "run-of-river" hydropower plant) or 2) hydropower dams with a limited storage capacity (the "reservoir") that is higher than the natural inflow (Førsund, 2007, p. 13).

2.7.1 Structure of the parent company

GKP is a 100% owned daughter company of Akershus Energi Vannkraft AS (AEV), the 9th largest hydropower producer in Norway (NOU 2019:16, p. 32). GKP contracts are administered and managed by AEV, but GKP has responsibility for the daily operations and maintenance of the plants. GKP sells its power to its parent, AEV, under a long-term contract at the market spot price and GKP takes no risk for the actual market transactions AEV undertakes secondarily. There is, however, a backward-looking correction made to the difference between the spot price and the actual price received. (Glomma Kraftprosuksjon AS, 2022, pp. 5-6)

AEV owns several run-of-river plants in the Glomma River system AEV is 100% owned by Akershus Energi AS (AE). AE acts as the holding group company for a group of power and energy companies. AE is 100% owned by Viken County, i.e., it is part of the Norwegian state's assets. (Akershus Energi AS, 2023, pp. 39-40)

2.7.2 Financial performance

The following tables and figures have been prepared by the authors. The source of this data is discussed in Chapter 5. Method. The objective of preparing Table 1. is to understand the cost structure and the drivers for profitability so we can determine the profit function to be used in modelling.

What we are looking for is to set out the available information in the accounts in a way that allows us to explore the fixed and variable cost elements and test the proposition that the variable costs are insignificant to the total cost picture and profit function and that the fixed costs remain reasonably constant over the years in the period tested. We expect to see fixed cost variability as, among other things, these costs change with personnel requirements. We are also looking to confirm or reject that a super-profit was made when power prices increased in late 2021. We also require this data to be able to complete the data required to construct Figure 14 and from this forecast the expected production costs for 2022. We need this as the accounts for 2022, were not published at the time of authoring, and it is required for the profit function.

Profit and Loss Statement ('000s kroner)	2014	2015	2016	2017	2018	2019	2020	2021
Income								
Income from Sales	220,971	167,072	218,540	271,210	357,324	379,514	101,210	732,173
Other operating income	5,480	3,776	4,272	7,530	10,014	6,312	5,143	18,816
Total Income	**226,451**	**170,848**	**222,812**	**278,740**	**367,338**	**385,826**	**106,353**	**750,989**
Costs								
Transmission costs	-9,141	-9,152	-8,897	-7,644	-7,802	-720	-9,856	-1,063
Salary and Wage costs	-7,819	-10,965	-12,822	-11,701	-11,028	-13,014	-10,874	-12,482
Other direct operating costs			2964	0		-132	0	0
Other indirect operating Costs	-48,779	-44,007	-40,882	-36,154	-34,631	-40,294	-46,875	-43,550
Concession fee	-2,372	-2,326	-2,311	-2,456	-2,432	-2,495	-2,413	-2,511
Operating costs	**-68,111**	**-66,450**	**-61,948**	**-57,955**	**-55,893**	**-56,655**	**-70,018**	**-59,606**
(EBITDA)	**158,340**	**104,398**	**160,864**	**220,785**	**311,445**	**329,171**	**36,335**	**691,383**
Depreciation and amortisation	-36,749	-35,425	-35,976	-40,152	-40,764	-41,646	-41,046	-42,335
Total Costs	**-104,860**	**-101,875**	**-97,924**	**-98,107**	**-96,657**	**-98,301**	**-111,064**	**-101,941**
Operating Result(EBIT)	**195,089**	**139,823**	**124,888**	**180,633**	**270,681**	**287,525**	**-4,711**	**649,048**
Finance Costs								
Interest earnt	674	1,425	183	31	312	1,516	589	325
Income costs	-13,472	-26,379	-12,077	-254	-33	-108	-318	-264
Net Finance	**-12,798**	**-24,954**	**-11,894**	**-223**	**279**	**1,408**	**271**	**61**
Ordinary Result before tax (EBT)	**182,291**	**114,869**	**112,994**	**180,410**	**270,960**	**288,933**	**-4,440**	**649,109**
Tax payable on ordinary result	-67,737	-33,962	-65,472	-105,556	-157,137	-112,513	-4,634	-247,557
Tax rate on assessment	*-37%*	*-30%*	*-58%*	*-59%*	*-58%*	*-39%*	*104%*	*-38%*
Net Profit After Tax (NPAT)	**114,554**	**80,907**	**47,522**	**74,854**	**113,823**	**176,420**	**-9,074**	**401,552**

Table 1. Profit and Loss statement for GKP 2014-2021

Price and Income

The wholesale power price in the NO1 bidding zone is set by the Nord pool using PCR Euphemia, which we have discussed in Chapter 2, is based on the variable marginal cost of the last power plant needed to meet demand in the entire system, adjusted for transmission capacity constraints.

The income for a day is determined by the integration of the product of hours in the period of production volume (MWh) and market price (EUR/MWh). Assuming that the generators cannot exceed their posted maximum electrical capacity under any flow conditions (are not generation capacity constrained) and are online 100% of the time period, the total production of power (MWh) is determined by the inflow conditions, which are in turn determined by environmental factors like rainfall and snow melting, but also by the release and storage of stored water in reservoirs upstream of GKP (NOU 2019:16, p. 21). The reality is that “Power production at any time is directly coupled to the current discharge in the river” (Boucher et al., 2020, p. 14), and this is not in control of the operator. It is clear that GKP has no direct control over price and limited control over production volume with the exception of planned downtime or major upgrades.

Costs

The nature of the costs must be understood for hydropower plants as they differ from the higher marginal cost thermal plants fired with coal and gas and from the other renewables. The literature review in Chapter 3 reveals a significant fact that the variable cost of power production from hydropower is almost insignificant compared to the fixed costs. (Førsund, 2007, p. 15) found that “Empirical information indicates that traditional variable costs, i.e., costs that vary with the level of output, can be neglected as insignificant”. This has relevance to the estimation of profit.

The account notes for GKP (Glomma Kraftprosuksjon AS, 2022) confirm that day-to-day maintenance costs are treated as fixed across the year and independent of production. There are some visible variable costs in the accounts for GKP, such as the concession price, a fee paid on a øre/kWh basis, but this is minor as it applies to only 2.2% of the total production, this being the production share the municipality GKP is located in utilizes.

The price, income and cost conclusions above have two important implications for profit and for how the plant is operated. Firstly, the marginal cost of production is one of the lowest in the generation marketplace, and this means that it always will be dispatched before thermal plants (unless there is a transmission constraint) and hydro-dam plants. The second is that, to be most economically efficient, the GKP plant should operate continuously to maximize its revenue and lower its unit cost of production by doing so.

3 Literature Review

The purpose of this literature review is to give an overview of relevant research papers that focus on the discussion of the importance of various internal and external variables in the context of their effect on spot electricity prices. Not all articles are specific to the Norwegian market or the NO1 bidding zone, however, the main principles translate well across electricity markets.

Døskeland et al. (2022) looks at how the presence of the two new interconnector cables, NordLink and NSL, affect the Elspot price in Norway. It observes that the Norwegian TSO, Statnett, examined the price effect of the links for the year 2021. By utilizing two common industrial modelling tools, Samnett and BID 3, and taking market capacity constraints into consideration, a simulated market response was obtained that compared the Links operation to a situation where the two new interconnectors were offline. This found that NordLink and North Sea Link explain only 10% of the increase from the average price for southern Norway in 2021. Other key findings in the report show that there are a wide range of outcomes that are dependent on a range of variables. For example, when a surplus of power is generated in Norway during a wet summer, Norwegian prices will on average increase, but when a deficit exists in a cold and dry winter, the cables will contribute to a reduction in price. It is also clear that the price effect is greatest in Southern Norway where our NO-1 bidding zone is located.

Finon and Romano (2009) discuss the impact of the increasing market integration of low-cost electricity countries to high-cost electricity countries, confirming that while the social welfare of the integrated market is increased and assuming no capacity addition, social welfare is simply redistributed and the consumer surplus in the low electricity cost country is reduced by higher prices. It points to future challenges for Scandinavian countries when Scandinavia is physically linked to German and Dutch markets due to price convergence.

As interconnectors represent increasing integration and price convergence, we see this as confirmatory to Døskeland et al., that the addition of NordLink and NSL cables should increase price in NO1.

Huisman (2008) investigates the impact of temperature on day-ahead electricity prices with a particular focus on its utility in replacing reserve margin (the difference between demand and maximum system supply capacity) in allowing for easier modelling of the probability of quick and large increases, or spikes in price. It develops three regime switching models, one without temperature dependency, one in which temperature affects the general price level and one in which temperature affects also transition probabilities. The results show that the further temperature deviates from average temperature levels, the more prices in day-ahead markets increase as does the price volatility. The paper concludes that temperature can be used as a proxy variable that replaces reserve margin under the assumption that temperature directly influences demand for electricity consumption.

Huurman et al. (2012) investigate the role of weather variables in forecasting electricity prices in real-time day-ahead markets. The results suggest that the use of weather forecast information as variables can provide new insights into the weather premium for prices.
The study forecasts prices in the Nord Pool market's Oslo (the NO1 bidding zone) and Eastern Denmark bidding zones using weather forecasts to improve forecast accuracy. The authors employ several ARIMA models, but their findings show that an ARIMA model extended with power transformations for next-day weather forecasts (ARIMAX) produces the best point forecasting results. **S**ARIMA**X** is a seasonal equivalent model that in addition includes **S**easonal effects and e**X**ogenous factors.

Huisman et al. (2013) looked at how prices are impacted by an increase in renewables. It concluded that an increase in renewable power supply, which includes hydropower and wind power reduces power prices. There is no transmission constraint and no area price difference between NO1 and the adjacent bidding zones NO2 and NO5, with the latter being dominated by dammed hydropower. Huisman et al. state that reservoir filling has an important role in setting marginal price. A run-of-river plant is ‘always on’ and will typically have a lower marginal cost than dammed hydropower.

Frydenberg et al. (2014) looked at the long-term relationships between the energy commodities (oil, natural gas and coal) on futures in the Nordic, German and UK energy markets. It concluded that there is indeed co-integration, and it is regional, it also stated that the co-integration appears stronger when the market has an increasing market share of generation from thermal plants utilising these commodities as energy sources. It is weaker in more hydropower heavy regions like the Nordic area.

Torró (2009) looks at the utility of futures prices for forecasting spot prices at Nord Pool. He compares the power of this forecasting approach to that of using a time-based series approach with external variables in the ARIMAX model. He demonstrates that the time series forecasting is consistently superior to using futures. He shows that the errors inherent in futures modelling increases as the maturity date increases and suggests that traders taking positions in the weekly futures market could benefit from using the ARIMAX modelling approach. It gives warning that anytime futures prices are used, it may introduce errors and is less likely to be accurate than actual daily spot price, because futures price includes expectations on the development of supply and demand and for and additionally transportation and storage costs.

(Amouroux, 2004) states that seventy five percent of the cost of hydroelectric electricity are financing of the invested capital (land, dams, generation and transmission equipment, capitalized maintenance, upgrades etc.). The other twenty-five percent represent the operating costs over the lifetime, including salaries, day to day operating maintenance costs. It notes that the fuel, which is the water that drives the turbines, unlike for coal or natural gas, has no cost for the operator. It also conveys that the variable costs of water are effectively zero because water is not purchased in a marketplace.

3.1 A significant market event during the sample period

The Russian invasion of Ukraine in February 2022 has changed the global energy landscape and no more dramatically has this been seen than in Europe’s soaring energy prices and an acceleration of policy and action in support of a transition to renewable energy. Russian gas dominated European supply at an average of 40% from 2018 to 2021 and 23% in 2022. The impact of sanctions, successful sourcing from alternative sources, and reductions in consumption reduced that share to below 10% in January 2023. (International Energy Agency, n.d.). A range of policy responses to subsidize energy prices was implemented. At the same time wholesale prices of electricity and gas grew by a factor of fifteen in the period since 2021. This has placed great pressure on households and businesses in Europe.

Gas prices rose on the reduction of cheap Russian supply and its replacement with more expensive sources like liquefied natural gas (LNG). LNG was initially already relatively more expensive than pipeline gas but has risen by a factor of two since the invasion. At the same-time a shortage of nuclear power and hydropower in Europe meant that gas and coal-fired thermal power generation was required, both of which generate at higher marginal costs. Demand destruction has also taken place and small changes in supply have had a large impact on prices driving the increase in the volatility of the spot price. (Zettelmeyer et al., 2022)

4 Data Source and conversion for use

The source data files are downloaded from several databases listed in Table 2.
Nord Pool and ENTSO-E are the primary sources for power exchange related data while weather and environment data are sourced from the Norwegian Meteorological Institute (MET). Statnett has been the source for consumption and demand data. Energy commodities are sourced from Eikon. The data covers the period from 1st January 2011 to 31st December 2022.

The European association for the cooperation between transmission system operators (ENTSO-E) is a collaborative effort. A transparency platform has been developed by ENTSO-E with the objective to provide free, continuous data access to Load, Generation, Transmission, Balancing, Outages and Congestion Management participants (ENTSO-E, n.d.).

For the thesis, when predicting NO1 pricing for changes in interconnect capacity, the transmission capacity to external countries from NO1 and NO2 were used. NO2 represents an adjacent bidding zone that has no transmission constraints with NO1 and as a result identical prices or total price convergence. As a result, only the connections listed below were used in the relevant Scenario, as shown in figure 1.

- Eastern Norway to Sweden (NO1-SE3)
- Skagerrak (NO2-DK1)
- NordLink (NO2-DE)
- NorNed (NO2-NL)
- North Sea Link (NO2-GB)

Time Series Issues

The ARIMA model uses daily time series data sets for its input. The data has where necessary, been re-sampled to if it was not provided in the required time series format. The method used for resampling was as follows.

- Weekly to daily: upsampling, simple division of the weeks data by seven for each of the seven days of that week.
- Hourly to daily: downscaling, depending on the data set it will be the addition of the mean.

Resampling can affect the quality of the model´s output. When resampling data, the underlying distribution of the data is necessarily altered. The statistical properties of the data can then be impacted, for example mean, variance and autocorrelation. SARIMAX is a type of time series model that relies on the statistical properties of the data, including its mean, variance and autocorrelation and may perform differently when trained on resampled data. The method used to fill in missing values during resampling can also affect the quality of the model´s output. Because of various methods of resampling, bias or noise has likely been introduced into the data. This can lead to overfitting or underfitting when the model is trained on the resampled data (Kuhn & Johnson, 2019).

We have not used spot prices for the commodity data but forwards prices. The forward market for commodities is a quoted one and the data for this is readily accessible to us. Spot prices are not always easily accessible without large fees for access to private databases. In Chapter 3 Literature Review, we have reviewed warnings about the data quality implications of using forwards prices in time series modelling (Torró, 2009), however this was unavoidable.
Spot price is what a commodity is trading at on the market currently. It reflects the commodity price one would transact at if it was purchased that same day and importantly in

distinguishing it from a future price, for immediate and not future delivery. It takes supply and demand into consideration but is not necessarily specifically calculated. It is often simply an economic concept. Spot prices are most frequently referenced in relation to the price of commodity futures contracts but they are not calculated from the futures price, while the reverse statement can be true (Nickolas, n.d.).

Variable (Units)	Weekly	Daily	Hourly	Data Source
Day-ahead electricity price NO1 (EUR/MWh)			x	Nord Pool
Export Capacity (MW)			x	Nord Pool
Import Capacity (MW)			x	Nord Pool
Export Flow (MW)			x	Nord Pool, ENTSO-E
Import Flow (MW)			x	Nord Pool, ENTSO-E
Natural Gas Price (EUR/MWh)		x		Investing.com
Coal price (EUR/MWh)		x		EIKON
Brent Crude Oil Price (EUR/MWh)		x		EIKON
EUA Price (€/t)		x		Energiogklima.no
Temperature (°C)			x	MET
Precipitation (mm)			x	MET
Wind (m/s)			x	MET
Reservoir Filling (%)	x			NVE
Production (MWh)			x	Statnett
Consumption (MWh)			x	Statnett
Production GKP (MWh)	x			Akershus Energi

Table 2. Summary of data type, source and sampling time period (source: author)

4.1 Spot Price (NO1)

The data for day-ahead prices, also known as spot price, was downloaded (obtained) from the pan-European power exchange (Nord Pool) over their Secure File Transfer Protocol server (SFTP) and for the Norwegian bidding zone NO1. The spot price was as periods of data in one-week blocks and with an hourly data periodisation. The SARIMAX model required the data to be resampled from hourly to daily to align with the time series frequency of the SARIMAX forecasting model. In addition, the original data included spot prices for all bidding zones in Norway, but these have been excluded, since they are of no interest for this study.

4.2 Transmission capacity

Capacity is defined as the quantity of electrical power that can be transmitted over a power cable without violating the operating safety and security standards. This considers the physical specification of the cable, the demand on the system and the operational limits set by the TSO to ensure the entire system operates within the system limits (FINGRID, n.d.). It is expressed in Nord Pool and ENTSO-E data sets in units of megawatts (MW). To calculate the capacity in a 24-hour period (day) the forecast capacity has been multiplied by twenty-four hours. Further capacity can be restricted in one direction compared to the other (in bipolar transmission system). The SARIMAX model uses both import and export capacity data as we will look at the impact of both on NO1 spot price. Since all the interconnect links modelled are for transmission across borders and designed for both import and export purposes, (bipolar links) this data is available. The individual interconnector links used in the predictive model are described in more detail below and in Table 3 and illustrated in figure 1. International connections map.

Data for capacity is collected from both ENTSO-E and Nord Pool. Nord Pool through their SFTP server and consists of hourly data. This has been resampled to daily data in order to align with the frequency used for our forecasting model. The capacity data will focus on the following HVDC cables connecting to the Norwegian electricity market to the UK and European continent. We also include exchange capacity to Sweden through its integrated electricity grid with Norway.

Interconnector name	Capacity (MW)
Nordlink	1,400
NorthSea Link	1,400
NorNed	700
Skaggerak	1,700
Sweden	2,145
Total	**7,345**

Table 3. Interconnector Capacity

NordLink – The NordLink project is a subsea interconnector between Norway and Germany. The NordLink project underwent a trial operation period from December 9, 2020, until March 31, 2021, but due to onshore transmission constraints was not operated at full capacity for some years. The interconnector has been in operation for two years and some network constraints still appear to remain in place to constrain the link on some days from reaching full capacity (Statnett, 2020).

North Sea Link (NSL) – The NSL power cable connects Norway and the UK. The NSL project started its trial operation period on October 1st 2021 (Statnett, 2021b) and started regular operation one year later, in October 2022 (Statnett, 2022a).

NorNed – The Norwegian and Dutch electricity grids have been interconnected by the NorNed cable since 2008 (TenneT, n.d.).

Skagerrak – The Skagerrak transmission system provides the ability for energy exchange between the Norwegian and Danish electricity market and compromises four HVDC links. The last cable introduced was Skagerrak 4 in 2014 (Statnett, 2013).

Sweden and Eastern Norway

The Swedish SE3 and Norwegian NO1 bidding zones are adjacent to one another and have a combined maximum exchange capacity of 2,145MW. This capacity for exchange is provided through a closely integrated power grid and form part of the Nordic synchronous grid (Statnett, 2022b).

4.3 Cross-Border physical flow

The ENTSO-E Transparency platform is used to collect data for cross-border physical flow. Flow is typically measured in power as amperes (A) but here is MW/unit time and defined as the integrated data for actual export or import power transmitted (MW) calculated every 15 minutes to daily data by adding the flow data point over a period of twenty-four hours. This means our flow data has the unit MW/day.

4.4 Production and Consumption

It was the original intention of the project to utilise the bidding zone production and consumption data. This was available publicly from Statnett in an hourly time series however it was only available at a consolidated level for all of Norway and could not be provided for our use to bidding zones of relevance.

4.5 Commodities Coal, Oil, Natural Gas

Data for Coal prices and Brent Crude Oil were retrieved from the EIKON database, "an open-technology solution for financial markets professionals, providing access to industry-leading data" (Refintiv, n.d.). The data set for coal is the ICE Rotterdam coal futures, API2, which is considered by investors to be the benchmark of coal prices in northwest Europe and is the world´s most referenced price assessment for coal (Aizarani, 2023). We use ATWYc1 data set which has a settlement date of 1 month.

Natural Gas prices for Europe are sourced from a Dutch location through the Transfer Title Facility (TTF). The TTF is considered by the EU as the continent's leading benchmark (European Commision, 2022) and the daily price quoted is a futures price for 1 month ahead. TTF data is published and available and downloaded from the website (www.investing.com). This data consists of daily data with data gaps/missing values for the weekends, this due to trading ceasing over the weekend. To address the missing data the forward filling method was used, where the datapoint value the prior Friday is used to fill in the values for the next two days (Saturday and Sunday).

4.6 Carbon prices/ EUA allowance

EU allowances (EUA) are carbon credits traded under the European Union Trading Scheme (EU ETS) and are issued by the 28 member countries plus Iceland, Lichtenstein, and Norway (European Commision, 2016, p. 1). The reason for its inclusion in the modelling is our proposition that under the cap-and-trade mechanism, the total greenhouse gas emissions are limited for major sectors of the economy, including power generation. As the price of carbon increases, the demand for renewable energy will likely increase and according to the law of supply and demand, price should correspondingly increase for renewable energy. This makes investment in the renewable energy more attractive. (European Commision, 2016, p. 2) European EUA´s price may therefore affect NO1 pricing.

4.7 Reservoir filling in NO1.

Reservoir filling describes the percentage of the hydro-dam water capacity that is filled. Reservoirs are filled by rainfall in the catchment area, water inflow from tributary rivers that raise the level of the dammed river, and snow melting (Energifakta-Norge, 2022).

Reservoir filling data is gathered from The Norwegian Water Resources and Energy Directorate (NVE) and consists of weekly data observations. This is downscaled to daily data by dividing the applicable weekly data by seven for each day of the week.

It would seem logical to assume that in a bidding zone where a dominantly large proportion of the capacity is run of river and a small share of capacity is hydro dam, that reservoir filling in that area would not be decisive as a variable to determine power price in that bidding zone as it would only marginally affect production totals.

4.8 Weather variables

The weather variables temperature, precipitation and wind speed are modelled to recognise that both electricity demand and supply are subject to weather conditions. Weather data for bidding zone NO1 were retrieved from the Norwegian Meteorological institute through their API, the Frost database. From the mentioned database we retrieved the following weather variables through weather station Blindern SN18700: air temperature is in degrees Celsius °C, total precipitation in millimetres (mm), and wind speed in meters per second (m/s). The data sets were hourly and were resampled to daily data.

The bidding zone NO1 is a relatively small geographical area, and it is assumed for the modelling that the weather effects are relatively homogenous and a single centrally located weather station may be used as a representative measure for the region. Blindern SN18700 weather station located in Oslo is selected as the weather station for the NO1 weather variables.

Temperature and wind speed: We addressed missing values through interpolation through forward filling. The number of missing values was relatively low which allowed us to use a relatively recent data value for the forward filling reducing the probability of a large departure from actual values of the imputed data.

Precipitation: Missing hourly data values occurred at time data points when there was no precipitation according to daily data values. Missing data was consequently set to zero.

4.9 Hydro Production at GKP

The source of data for hydroelectric production for GKP was the group owner, Akershus Energi. It consisted of data from 2010 to the end of 2022. The data has been pre-processed for weekly data and has no missing values. In order to convert the data to our sampling frequency, we divided the relevant week by seven.

Source of financial data

The information is transcribed from individual the Annual Reports of GKP for the years 2014 to 2021 as officially audited accounts registered with the Brønnøysund Registry (brreg.no). We have identified errors that are of no material importance to our conclusions, and we consequently ignored those minor errors or omissions in the supplied data. We also noted some discrepancies in the data between the published annual reports of GKP and the official annual reports. We have assumed the official registered reports to be the latest and most correct source of financial information.

5 Methodology

There are several methods commonly used for electricity price forecasting. The choice of method depends on its suitability to various factors such as the data availability, the desired forecasting horizon, the presence of seasonality or trends, and the specific characteristics of the electricity market. Common methods are Autoregressive Integrated Moving Average, Hybrid approaches, Exponential Smoothing, Regression and advanced methods including Neural Networks and Vector autoregression. (Hyndman & Athanasopoulos, 2021)

In competitive electricity markets, data is available in time series with hourly sample periods. The data sets have the following typical characteristics that should be considered when selecting a price modelling tool and methodology:

- daily frequency
- non-constant mean and variance.
- multiple seasonality
- calendar effects
- high volatility
- a high percentage of unusual prices (mainly in periods of high demand) due to unexpected or uncontrolled events in the electricity markets. (Amjady & Hemmati, 2006, pp. 22-23)

We have selected a seasonally adjusted autoregressive integrated moving average methodology called SARIMAX. The SARIMAX Model, being a statistical model, has better interpretability than machine learning models such as neural networks, which require a rather large amount of data compared to the SARIMAX. Further, the SARIMAX model is a good model when adding exogenous variables with seasonality.

Another regressive time series method such as GARCH is likely to be able to capture the volatility of the electricity market more effectively than SARIMAX, however we didn't find utility for this because were able to use average values rather than the normal day-to-day forecasting. That choice can be justified because focusing on the average value provides a more stable and reliable estimate that is less susceptible to noise and short-term fluctuations in the data. This approach is particularly useful in the context of highly volatile times series data, such as electricity spot prices in 2022. Additionally, GARCH does not consider seasonal effects very well. SARIMAX was considered more suitable for our purpose. One option we looked at was to use a SARIMAX-GARCH method, that combines both individual methods. However, we were not successful implementing this model and decided to use average values.

5.1 The SARIMAX method

SARIMAX (Seasonal Autoregressive Integrated Moving Average with exogenous variables) is a time series model that has been used to forecast values of a time series variable. It is an extension of the ARIMA (Autoregressive integrated Moving Average) which includes additional terms for seasonal effects and exogenous variables.

The SARIMAX model consists of several parameters, including autoregressive (AR) and moving average (MA), and seasonal AR and MA terms. These parameters help capture the underlying patterns and dependencies in the time series data. The seasonal ARIMA includes several seasonal terms and is written as follows:

$$\text{ARIMA} \qquad \underbrace{(p, d, q)}_{\substack{\uparrow \\ \text{Non-seasonal part} \\ \text{of the model}}} \qquad \underbrace{(P, D, Q)_m}_{\substack{\uparrow \\ \text{Seasonal part} \\ \text{of the model}}}$$

Figure 6. Seasonal terms (source: Forecasting principles 9.9)

S: Seasonality (m) – This refers to the presence of a repeating pattern or cycles in the data that occur at fixed intervals, such as daily, weekly or yearly.

AR: Autoregressive (p) - The autoregressive term is based on that the future values of the time series variable are dependent on past values of the same variable, meaning the AR term captures this relationship by including lagged values of the variable in the model.

I: Integrated (d) - This refers to the process of differencing. This is used to make the time series stationary. It is important that the data is stationary in time series methods. Therefore, we can say that the 'I' indicates how many times the data needs to be differenced to become stationary.

MA: Moving Average (q)– This refers to that future variables of the time series variable are dependent on past values of the error term. It captures the relationships by including lagged values of the error term in the model.

X: Exogenous - In addition to these parameters the model can include exogenous variables which can be used to increase the accuracy of the forecast by accounting for external factors which can influence the endogenous variable, which in our case is the electricity spot price for NO1 bidding zone (Hyndman & Athanasopoulos, 2021).

5.2 Model Specification

Model specification is the process of determining which independent variables to include and exclude for the method selected, determining the seasonality in the data as well as the AR, I, MA components.

5.2.1 Variable Selection

Our approach for variable selection was systematic and involved several steps to ensure robust selection and validation. Our first step was selecting appropriate exogenous variables to include in the SARIMAX model. We utilised a combination of domain knowledge and analytical techniques to accomplish this, among them Variance Inflation Factor, Correlation matrix and Multiple Linear Regression.

Variance Inflation Factor

First, we conducted a multicollinearity check using Variance Inflation Factor (VIF). This helped us identify and exclude variables with high multicollinearity, ensuring that our model's estimations would be reliable and interpretable. Variables with a VIF score above a certain threshold, typically 5 or 10, were considered to exhibit multicollinearity and were thus excluded from our model. None of our variables exhibited a MC over 10, however, Coal and Brent Crude Oil showed a VIF value above 5, (see Appendix A.1), which we had to evaluate if they were to be used later in our model (The Investopedia Team, n.d.).

Correlation matrix

Second, we utilized a correlation matrix to assess the relationships between potential exogenous variables and the target variable NO1 spot price. The correlation matrix allowed us to identify variables that had a significant relationship with the target variable, guiding our selection of exogenous variables for the model. We attempted to use a LASSO for feature selection but had poor results as it chose all the variables as relevant, which did not assist us to narrow the variables. This poor result may be due to the limited number of observations in our dataset, and because some variables have a similar correlation to the Elspot variable. The correlation matrix however looked at the correlation between the endogenous variable and the exogenous variables. The exogenous variables with the highest correlation were chosen for further consideration in the model.

Due to the high correlation between the commodities of coal, crude oil and natural gas, only one exogenous variable from these would be selected as shown in table 4. This would prevent multicollinearity which could cause an instability problem for SARIMAX. Natural gas has the higher relevance to power price, because this commodity is both more relevant to our thesis and has been blamed for the high electricity prices in 2022.

The exogenous variables of import flow and import capacity also had a positive correlation to the Elspot price, and both were selected for further evaluation. Weather variables, wind, precipitation, and temperature surprisingly did not yield a positive correlation with the endogenous variable. We consider this is due to the non-linear relationship between these factors and the Elspot price.

In Figure 8 and 9, we can see the correlation between variables before differencing and after differencing. We have defined differencing earlier. By plotting both, we are able to see to what extent these variables may affect the model by examining the correlation factors. For summary table (see Appendix A.2).

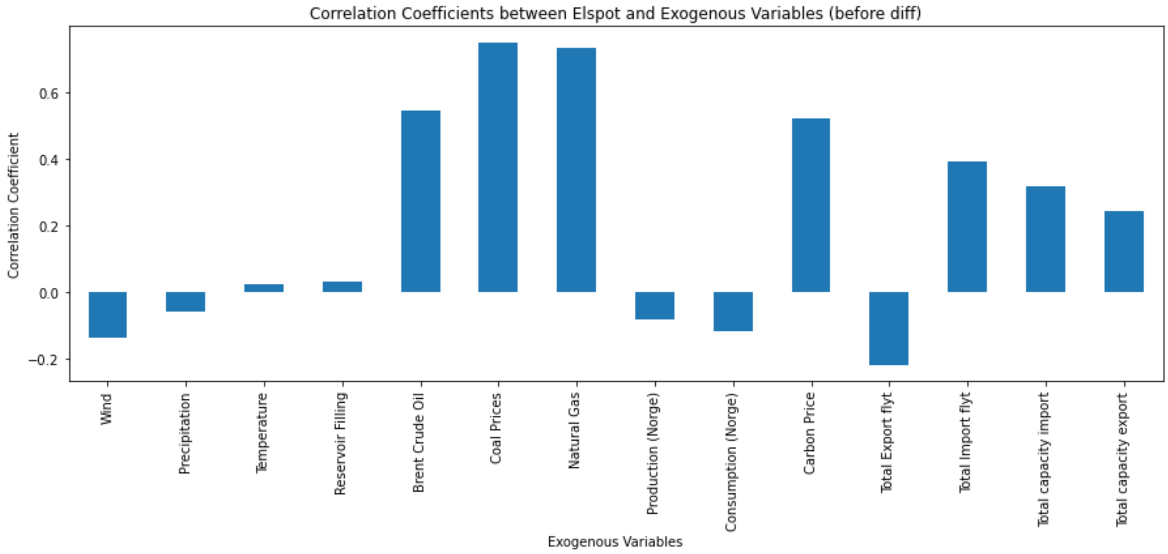


Figure 7. Correlation coefficients between Elspot & exogenous variables before differencing

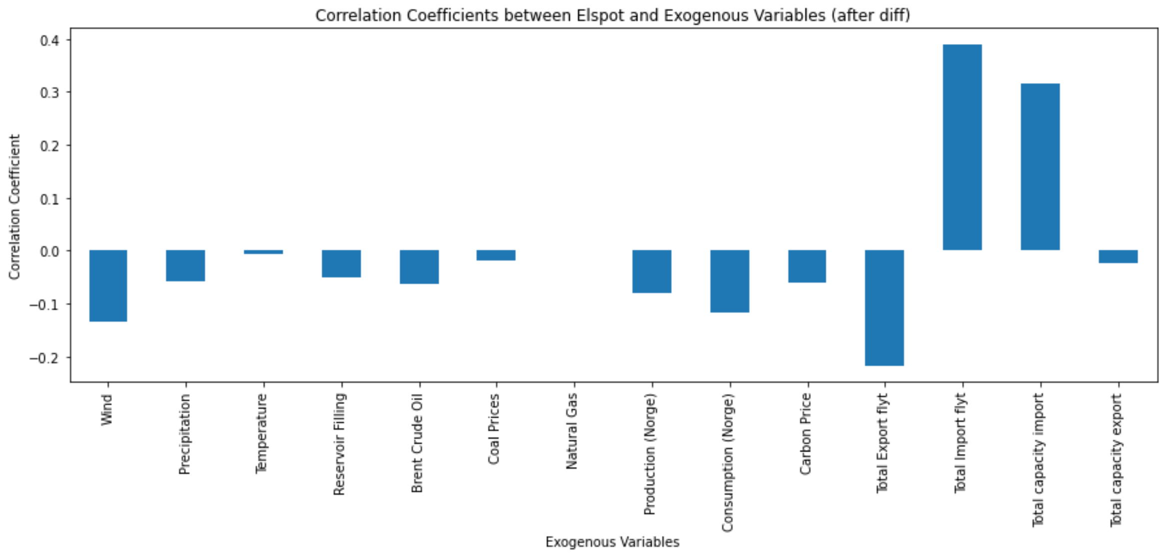
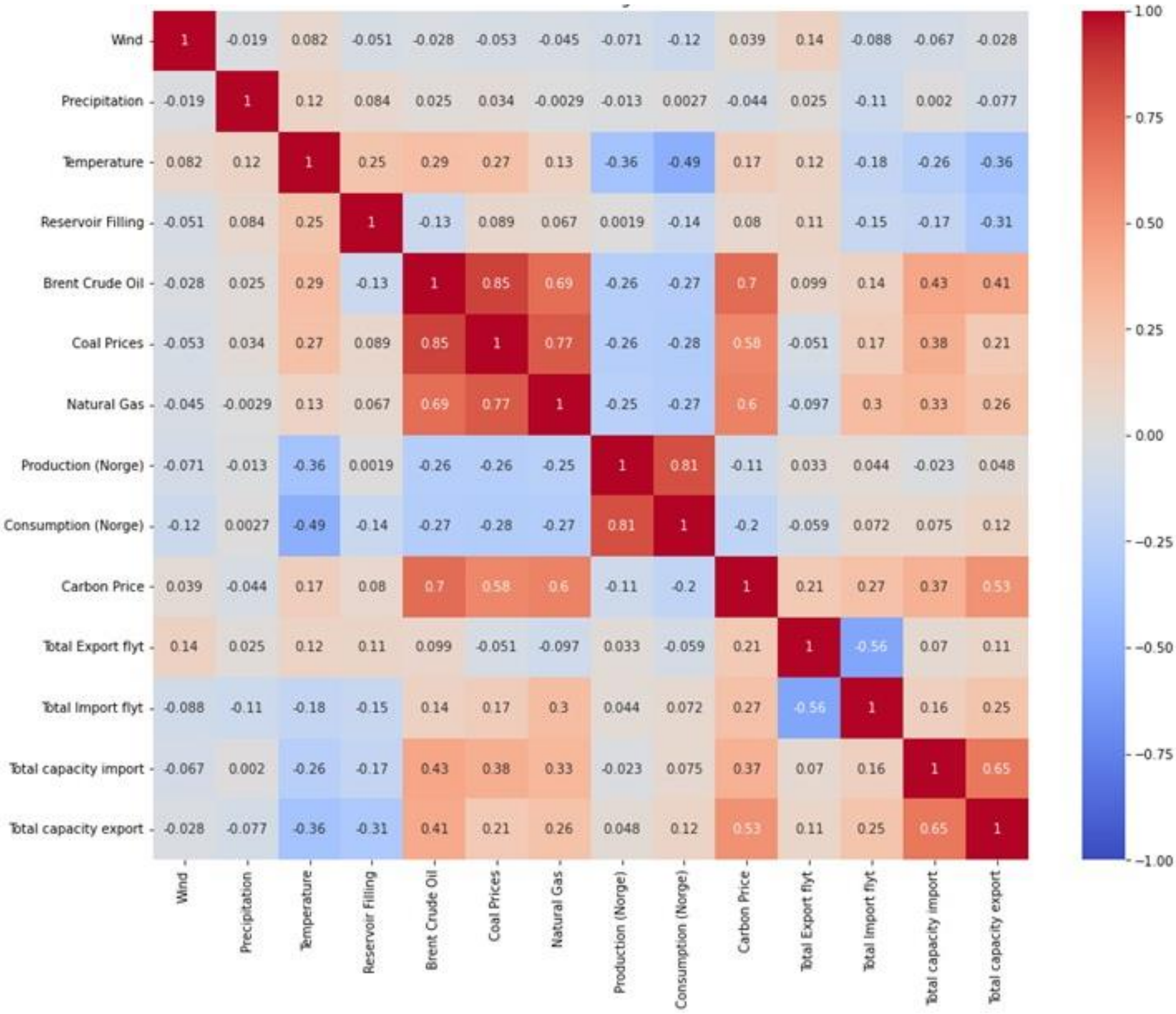


Figure 8. Correlation coefficients between Elspot & exogeneous variables after differencing



	Wind	Precipitation	Temperature	Reservoir Filling	Brent Crude Oil	Coal Prices	Natural Gas	Production (Norge)	Consumption (Norge)	Carbon Price	Total Export flyt	Total Import flyt	Total capacity import	Total capacity export
Wind	1	-0.019	0.082	-0.051	-0.028	-0.053	-0.045	-0.071	-0.12	0.039	0.14	-0.088	-0.067	-0.028
Precipitation	-0.019	1	0.12	0.084	0.025	0.034	-0.0029	-0.013	0.0027	-0.044	0.025	-0.11	0.002	-0.077
Temperature	0.082	0.12	1	0.25	0.29	0.27	0.13	-0.36	-0.49	0.17	0.12	-0.18	-0.26	-0.36
Reservoir Filling	-0.051	0.084	0.25	1	-0.13	0.089	0.067	0.0019	-0.14	0.08	0.11	-0.15	-0.17	-0.31
Brent Crude Oil	-0.028	0.025	0.29	-0.13	1	0.85	0.69	-0.26	-0.27	0.7	0.099	0.14	0.43	0.41
Coal Prices	-0.053	0.034	0.27	0.089	0.85	1	0.77	-0.26	-0.28	0.58	-0.051	0.17	0.38	0.21
Natural Gas	-0.045	-0.0029	0.13	0.067	0.69	0.77	1	-0.25	-0.27	0.6	-0.097	0.3	0.33	0.26
Production (Norge)	-0.071	-0.013	-0.36	0.0019	-0.26	-0.26	-0.25	1	0.81	-0.11	0.033	0.044	-0.023	0.048
Consumption (Norge)	-0.12	0.0027	-0.49	-0.14	-0.27	-0.28	-0.27	0.81	1	-0.2	-0.059	0.072	0.075	0.12
Carbon Price	0.039	-0.044	0.17	0.08	0.7	0.58	0.6	-0.11	-0.2	1	0.21	0.27	0.37	0.53
Total Export flyt	0.14	0.025	0.12	0.11	0.099	-0.051	-0.097	0.033	-0.059	0.21	1	-0.56	0.07	0.11
Total Import flyt	-0.088	-0.11	-0.18	-0.15	0.14	0.17	0.3	0.044	0.072	0.27	-0.56	1	0.16	0.25
Total capacity import	-0.067	0.002	-0.26	-0.17	0.43	0.38	0.33	-0.023	0.075	0.37	0.07	0.16	1	0.65
Total capacity export	-0.028	-0.077	-0.36	-0.31	0.41	0.21	0.26	0.048	0.12	0.53	0.11	0.25	0.65	1

Table 4. Correlation matrix of exogenous variables

Multiple linear regression

Multiple linear regression (MLR) is a method used in our study to identify potential relationships between the target variable and the exogenous variable considered for the SARIMAX model. MLR is a statistical method used to model linear relationships between a dependent variable and multiple independent variables. It helps us understand how the dependent variable changes with the independent variables and can be valuable in selecting the most relevant variables for further analysis with our SARIMAX model. The coefficients indicate the direction and size of the relationship between the endogenous variable and each independent variable.

P-values can be used to test the null hypothesis that the coefficients are equal to zero, and R-squared values provide information about the variance in the endogenous variable explained by the independent variable.

The MLR can provide valuable information into the linear relationships between variables, but it has limitations when applied to time series data. Specifically, MLR does not account for time series aspects such as autocorrelation, seasonality, and trends. Therefore, the results from the multiple linear regression should be considered a preliminary guide for selecting exogenous variables for the SARIMAX model rather than a definitive validation (Hayes, n.d.).

We plotted the variables into an MLR model and looked at what impact these variables may have on the model. The MLR shows that natural gas and carbon prices are the ones with the highest explanatory power, with a combined R-squared of 0.55. However, this is not surprising since the Elspot price seems to have a linear connection with these variables, as seen in the correlation matrix. Further, by looking at the weather variables in the MLR, they have no explanatory power, which we can also see in the correlation matrix. After differencing, the only variables that have any significant explanatory power are import flow and import capacity, with a combined R-squared of 0.165. The reason for this is most likely due to the fact that natural gas and carbon prices follow the trend of the Elspot price. As noted before, this model is a linear one and may not capture more complex patterns.

After running this through the SARIMAX model, the best variable to use was import capacity, as it gave the best average of the forecasted values, this is further shown in the results chapter. It is important to note that more complex feature selection models could have helped improve this selection process and made it even more robust towards the SARIMAX model.

5.2.2 Remaining selection tasks

With our variables selected, the next step was to specify the remainder of the SARIMAX model. This involved determining I, the appropriate order of differencing (d), the number of autoregressive AR terms (p), and the number of moving average MA terms (q) for the model.

Originally the dataset consisted of data from 2011 – 2022, but because of the large increase in electricity price during 2021 and 2022 we chose to only use the last two years. The reason for this is that in 2020 the prices were historically low, and because of this the model would be largely affected if choosing to use the electricity price pre 2021.

The model is split into training and test set from the dates 2021-01-01 to 2022-09-30 and 2022-10-01 to 2022-12-31, respectively. The reason for this is we would like to look at the last three months of 2022 and make a forecast for this period because this is when the newly installed NSL and NordLink cables, which underly the exogeneous variable Import Capacity became fully operational. The three-month period is helpful to forecast a full quarter of performance for the profit of GKP.

We employed a grid search strategy to systematically explore a range of possible combinations for these parameters and assist us with selection of the best parameters. However, the grid search output parameters (3, 0 ,0) (3,0,2,7), were found to not be optimal according to the ACF and PACF plots. We adjusted the parameters and by evaluating the model's performance for each combination, we were able to identify the most optimal parameters that minimized the forecast error. The final parameters selected for our model were (1,0,2) (1,0, 2, 7).

In order to identify the seasonality in the data we looked for regularly repeating pattern of spikes in the ACF plot. We saw spikes at lag 7, 14, 21 and because of this a seasonality of 7 (weekly) was selected (Hyndman & Athanasopoulos, 2021).

To confirm the final selected parameters, we examined the Autocorrelation Function (ACF) and Partial Autocorrelation Function (PACF) plots of the time series. The ACF plot helped us determine the appropriate number of moving average terms, while the PACF plot was used to identify the number of autoregressive terms. The ACF – plot in Figure 10 shows a slow decay, this can indicate stationarity, but because of the augmented dickey-fuller test (ADF), which shown a P-value of 0,0194, of the endogenous variable indicating it is within a 5% significance level, this has been ruled out, which confirms stationarity, ADF – tests for the other variables (see appendix A.3). The PACF plot shows that most lags are within the significance area, with lag 8, 11 and 16 being outside, as seen in figure 11. This is due to the volatility in the data that the model does not capture very well.

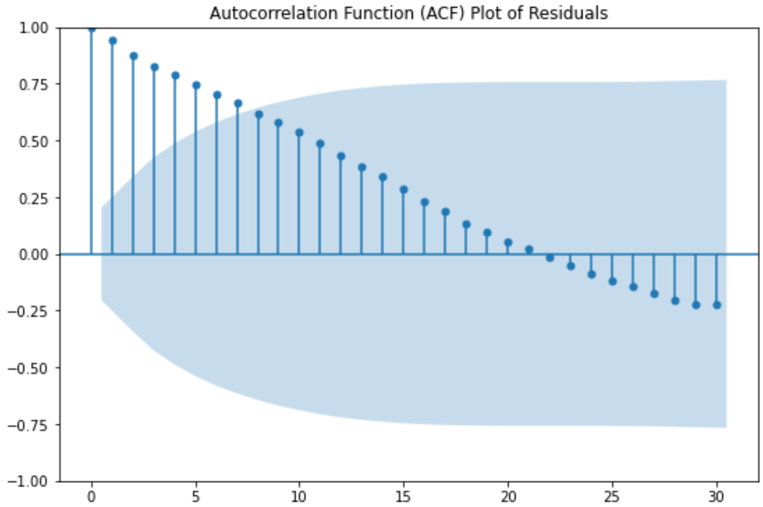


Figure 9. ACF plot of residuals

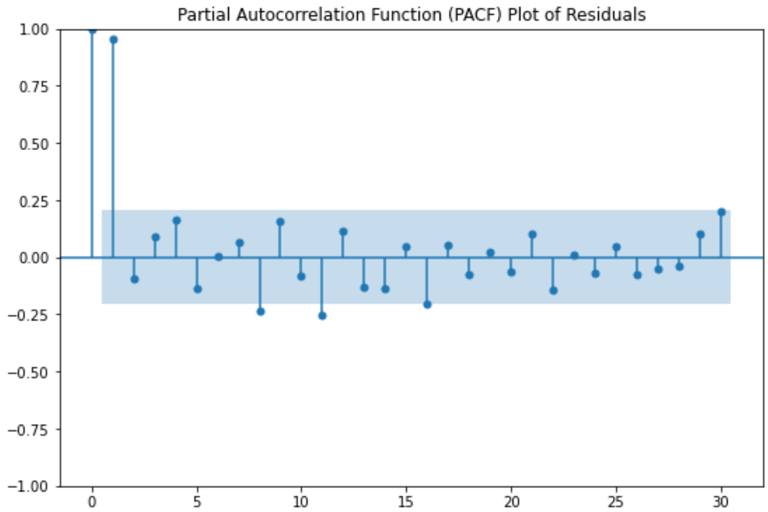


Figure 10. PACF plot of residuals

5.3 Model Validation

After specifying our SARIMAX model, we conducted a series of checks to validate our model. This included examining the residuals of the model to ensure they displayed no significant autocorrelation or patterns, indicating that our model had adequately captured the time-dependent structure in the data. (Hyndman & Athanasopoulos, 2021)

We evaluated the performance of the SARIMAX model using the appropriate performance tools such as the Ljung box test, The Jarque – Bera (JB) test. The primary performance metric used was the model's ability to capture the average electricity price over the next three months.

The Ljung box test is used to test for autocorrelation and checking if a time series consists of white noise (Hyndman & Athanasopoulos, 2021). The test resulted in a test statistic of p = 0.06 and a p-value of 0.81. Since the p-value is greater than 0.05, there is no significant evidence of residual autocorrelation at lag 1. This suggests that the model captures the temporal dependencies in the data. This can also be further confirmed with the correlogram (autocorrelation plot) shown in Figure 12. Output from Python's integrated diagnostic tool shows that most of the autocorrelation in the model is captured.

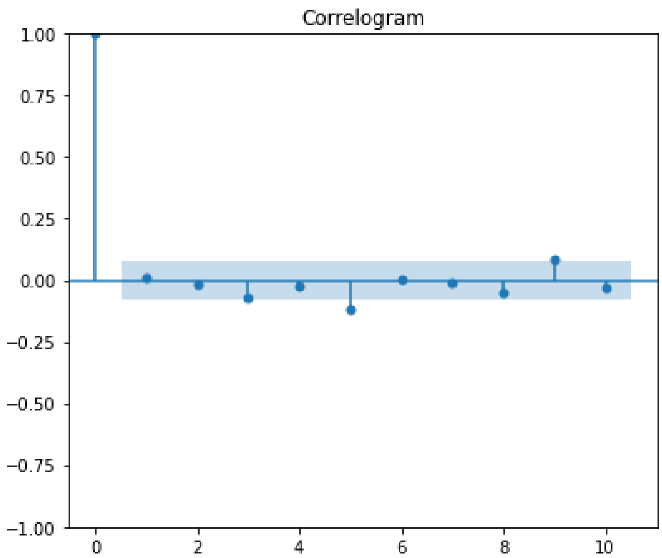


Figure 11. Correlogram showing the relationship between the time series and its past observations.

The Jarque – Bera (JB) test evaluates the normality assumption of the model residuals (DeJesus, 2022). In this model the test statistic is 2240.72 with a p-value of 0.00. These values signify that the residuals significantly deviate from a normal distribution. This is most likely due to the high volatility and the presence of outliers in our dataset. Since our model is based upon an average this is acceptable. This is further explained in the section 5.3.1 below. The model also shows significant heteroskedasticity, however since we are using a SARIMAX model it is capable of adapting to the underlying patterns and dynamics in the data and this is not causing a significant problem for this model.

5.3.1 Residual analysis

When dealing with highly volatile data and focusing on average values over a longer period, it is expected to have larger residuals or forecasting errors as seen in figure 13. This is because the volatility in the data leads to more significant fluctuations and unpredictable movements in the short term. However, when looking at the average values over a longer period of time, the impact of these day-to-day deviations tends to average out, resulting in larger residuals.

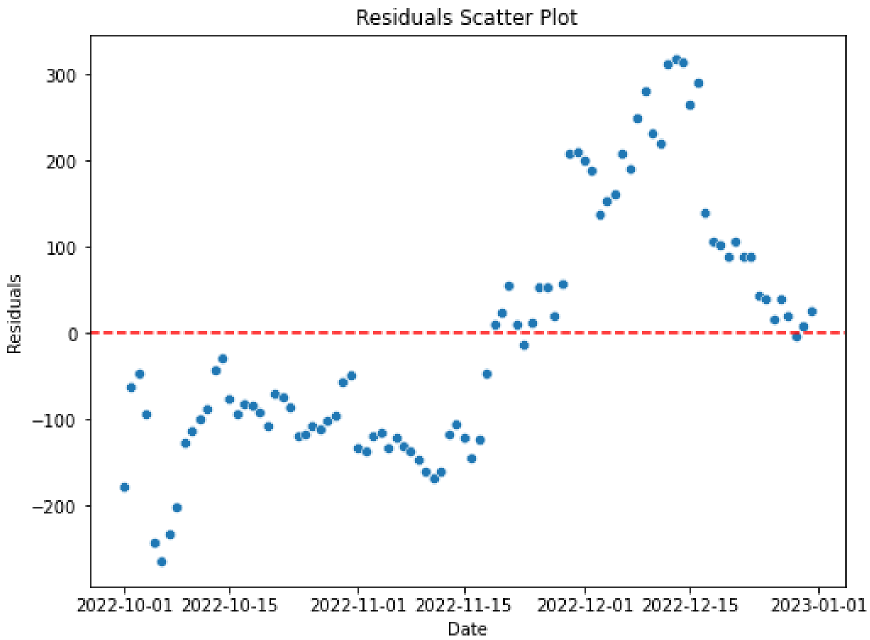


Figure 12. Plot over the residuals in the model

The reason for this being acceptable in this context is that the focus is on capturing the overall trend and average behaviour rather than the day-to-day fluctuations. The goal is to understand the broader patterns and the underlying factors driving the average values. In this case, the larger residuals reflect the inherent volatility and unpredictability of the data, which is an inherent characteristic of the electricity market. By forecasting over a three-month period, the values smooth out some of the short-term noise and capture the overall trend well. This approach helps to underline that the day-to-day fluctuations are not captured accurately due to the volatility. For summary of diagnostics (see Appendix A.4).

5.4 Scenario analysis

To enhance our understanding of the model's sensitivity to changes in the exogenous variables and test its robustness under different conditions, we conducted a series of scenario analyses.

5.4.1 Scenario 1: Increase import capacity.

In the first scenario, we simulated an increase in import capacity for the North Sea Link and NordLink cables connected to Norway. This was achieved by multiplying the respective capacities in the dataset by a factor of two, effectively simulating a doubling of the import capacity for these two cables. It's important to note that our model uses the total capacity import, so it does not specifically distinguish between different cables.

To test the effect of the recently commissioned interconnectors NordLink and North Sea Link on Elspot price for the NO1 bidding zone, we performed a scenario analysis to assess the potential impact of changes in the import capacity variable on the forecast average electricity prices. This involved increasing the total capacity import for the NSL and NordLink cables connected to Norway by 100%. The effect of this is to increase the maximum possible import capacity from a baseline of 7,345 MW to 10,145 MW or by 38%. This is shown in Table 5.

TABLE OF TRANSMISSION CAPACITIES (MW) and SHARE (%)					
Model Scenario		**Baseline**		**Scenario 1**	
Interconnector name	**Individual capacity**	**Combined**		**Combined**	
Nordlink	1,400	2,800	38%	5,600	55%
NorthSea Link	1,400				
NorNed	700	4,545	62%	4,545	45%
Skaggerak	1,700				
Sweden	2,145				
	7,345	**7,345**	**100%**	**10,145**	**100%**

Table 5. Transmission capacities for bipolar links from Southern Norway to Europe

5.4.2 Scenario 2: Introduce natural gas price as an exogenous variable.

First a calculated average value for natural gas between 2011-2022 was performed, and second these values were artificially increased by a factor of three, for the last three months in the dataset. This allowed us to explore the potential impact of substantial changes in natural gas prices on the forecast average electricity price.

For the commodities of natural gas, the spot price is considered as the month ahead futures price and so its use is questionable. However, we have not been able to secure daily spot prices for the commodities. It appears that the high liquidity in oil, gas and coal trade is because it is conducted in the futures derivatives market. We have consequently used month ahead futures data from one of two most mature and transparent hubs in Europe, the Dutch Title Transfer Facility (Chestney, 2022)

5.4.3 Scenario 3: Impact of Weather Variables

The final scenario involved the introduction of weather variables, specifically 'Precipitation' and 'Temperature'. We chose to use the ‘new climate normal’ as defined by the Norwegian Meteorological Institute (MET). This is an average of weather variables over the thirty-year period from 1991 to 2020. The basis for this choice is that it is very reliable, updated, and accepted industry standard and because climate change is accounted for in this ‘new’ periodisation (MET, 2021). We have adopted the MET’s approach to classifying weather periods as being for

- precipitation; very wet, wet, normal, dry, very dry.
- Temperature; hot, warm, normal, cold, very cold.

We had the objective to test for a 95th and 5th percentile case, which respectively translates to a hot and very wet and a very cold and very dry period. We adjusted the actual monthly values to levels that were representative of the 95th and 5th percentiles of precipitation and temperature levels using the quantile function in Python. This allowed for simulation of conditions of extremely high and low precipitation and temperature, and the examination of their potential impact on electricity prices.

Through these scenario analyses, we aimed to assess the model's performance under different hypothetical conditions, providing a more comprehensive understanding of the dynamics of electricity price forecasting. These scenarios not only tested the robustness of our model but also offered valuable insights into the potential influences of different factors on electricity prices.

In 2019, approximately 67% of electrical power production was from run-of-river plants like GKP. (Energifakta-Norge, n.d.) When there is more precipitation, production may increase due to more river flow but precipitation in NO1 does not set the marginal price of production, this is set by the marginal producers in dammed hydropower in the adjacent regions of NO2 and NO5. Neither does precipitation fill the reservoirs in NO2 and NO5 where the scarcity of water may have a strong effect on marginal price. Consequently, the precipitation in NO1 is not expected to have an impact on price in NO1.

5.4.4 Calculating Profit

The profit function requires three variables for the calculation. The first is the three-month average for October, November and December 2022 that constitutes our in-sample prediction for NO1 Elspot price, the calculation of which is the subject of the forecasting model. The second is production volume which is the sum of actual production data provided for the three months provided by Akershus Energi AS (Akershus Energi AS, Personal communication, March 2023). The third is production cost. The annual accounts for 2022 for GKP had not been released at the time of the authoring. For this reason, the average cost of production for the period of interest was estimated. Since there is no clear resolution on the breakdown between fixed and variable costs, it is assumed all costs are essentially fixed (see section 2.7 GKP). In order to estimate the production cost for 2022, the historical data in Table 6 and Figure 14 was scrutinised and on Figure 14 the likely position of the cost in relation to the history. The likely position is selected to maintain the graphs relational symmetry between the two data sets for both time and magnitude. From this estimation, it is assumed a total production cost per annum of 95 million Norwegian kroner, or 10.656 €/MWh.

Year	Annual Production (MWh)	Estimated Annual Production Cost (Million kr.)	AVG Annual Production Cost (kr./MWh)	AVG Annual Production Cost (€ /MWh)
2022	882,356	95.0	107.666	10.656
2021	1,004,151	101.9	101.520	10.047
2020	1,040,310	111.1	106.760	10.566
2019	1,006,782	98.3	97.639	9.663
2018	869,288	96.7	111.191	11.005
2017	1,023,543	98.1	95.850	9.486
2016	924,959	97.9	105.868	10.478
2015	1,025,729	101.9	99.320	9.830
2014	983,415	104.9	106.628	10.553
Forecast Estimated Value			Exchange rate Kr/€.	10.104

Table 6.GKP's Annual Production and Operating costs (2014-2021)

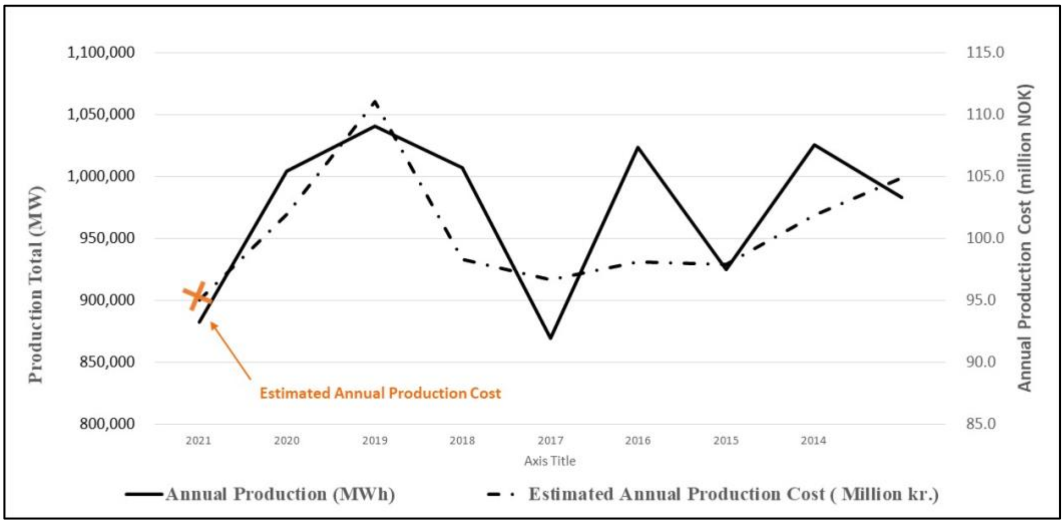


Figure 13. Annual production and operating costs (2021-2014)

6 Results

This chapter presents the results obtained from running the SARIMAX model. The model's performance is evaluated based on the model's ability to capture the average NO1 price, as discussed in chapter 5. For more detailed statistics (see Appendix B).

6.1 SARIMAX Model Performance

6.1.1 The Baseline Model

The selected model parameters used, proved to capture the underlying patterns in the data efficiently and this was a result we have already covered in the Chapter 5. Method.
We assess the modelling result by comparing the average of the forecast electricity prices over the next three months with the actual data for the same period. The result of the modelling for the Baseline Model forecast spot price and actual spot price is shown in Figure 15 and the 3-month averages for Baseline Model 1 forecast and Actual is shown in Table 9. The averages difference shows an absolute percentage error of approximately 2.6%. Given the inherent volatility and the wide range of factors impacting it, an electricity price forecast error rate of 2.6% indicates a relatively accurate model. However, we are unable to find industry specific benchmarks for 3-month forecasting accuracy to confirm this. The result demonstrates that despite the day-to-day fluctuations in electricity prices, the model managed to accurately forecast the average price over a longer-term period of three months.

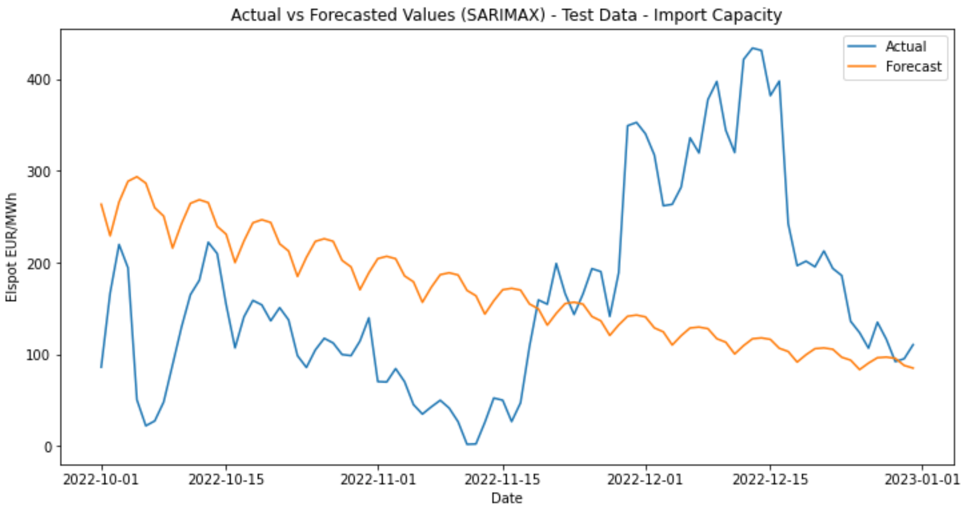


Figure 14. Baseline model

Baseline 4th quarter 2022	
Average Actual Elspot (EUR/MWh)	164.69
Average Forecast Elspot (EUR/MWh)	168.59
Total Actual Profit (EUR)	39,414,491
Total Forecast Profit (EUR)	40,411,869

Table 7. Baseline Model Results for the 4th quarter of 2022

6.1.2 Comparative Performance

Comparatively, traditional time-series forecasting models that focus on minimizing day-to-day prediction errors (measured using metrics like RMSE, MAE, MSE, or MAPE) would most likely not have been able to achieve the same level of accuracy in predicting the three-month average price or in estimating a profit for the quarter that could be trusted. The profit forecast can be used for financial planning purposes where scenario planning is incorporated. An accurate profit forecast from its subsidiaries could also help the parent AE with cash-flow planning and foresee potential funding requirement or payments from the operating companies either in form of debt repayments or dividends.

6.1.3 Estimating profit for GKP on the Baseline

Forecast profit for the modelled period of 40,411,869 EUR was returned for our baseline model. Assuming stable prices and production over the full 2022 year, this annualizes for 2022 at revenue of 161 million EUR.

6.2 Results of Scenario analysis

This section will present the results for the three different scenarios, showing the impact of local and external factors on the NO1 Elspot price and consequently the impact on profitability for the County owned run-of-river producer Glomma Kraftproduksjon AS.

6.2.1 Scenario One: Doubling of the NordLink and North Sea Link capacity.

After adjusting the input to the SARIMAX model to reflect this scenario, we observed significant increases in both price and GKP profit compared to baseline.
The result of the modelling for Scenario 1 forecast spot price and actual spot price is shown in Figure 16 and the 3-month averages for Scenario 1 forecast and Actual is shown in Table 10. The new forecast average price was 229.35 EUR/MWh representing a substantial increase of 36% over the baseline model. Through this scenario, the forecast profit for GKP increases 38% from 40.412 million Euro to 55.96 million Euro. See Table 10.

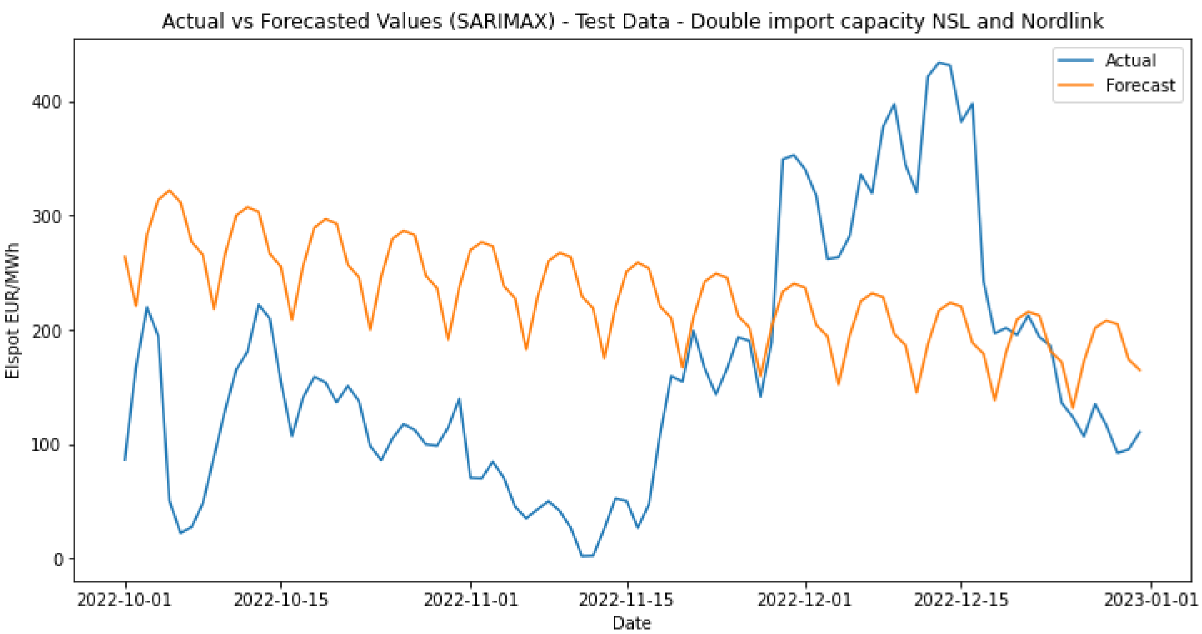


Figure 15. Scenario 1 - Double import capacity NSL and NordLink

Scenario 1 versus Baseline		
	Baseline	**Scenario 1**
Average daily 3-month Import Capacity Total (MWh)	184,553	238,799
% of total Import Capacity		29%
Average daily 3-month Import capacity Nordlink, NSL (MWh)	62,124	124,221
% of original sub-total	100%	200%
% increase for Scenario 1		100%
Average 3 month spot price (EUR/MWh)	168.59	229.35
% price change from Baseline		36%
Forecast GKP profit for the period (million EUR)	40.41	55.96
% Profit change from Baseline		38%

Table 8. Summary of Results of modelling for Scenario One

This outcome underscores the sensitivity of the market to changes in the import capacity variable. It indicates that an increase in capacity import via the NSL and NordLink interconnectors should potentially lead to a substantial rise in the average electricity price and profit for GKP.

6.2.2 Scenario Two: Inclusion of Natural Gas

To test to what extent Natural Gas prices effect NO1 spot price, we have in this scenario increased natural gas prices by a factor of three (200%) from the average natural gas price. The results are shown for the four sub-scenarios modelled in Figures 17,18,19 and 20. Four sub scenarios were modelled due to challenges found in the choice of the exogenous variable.

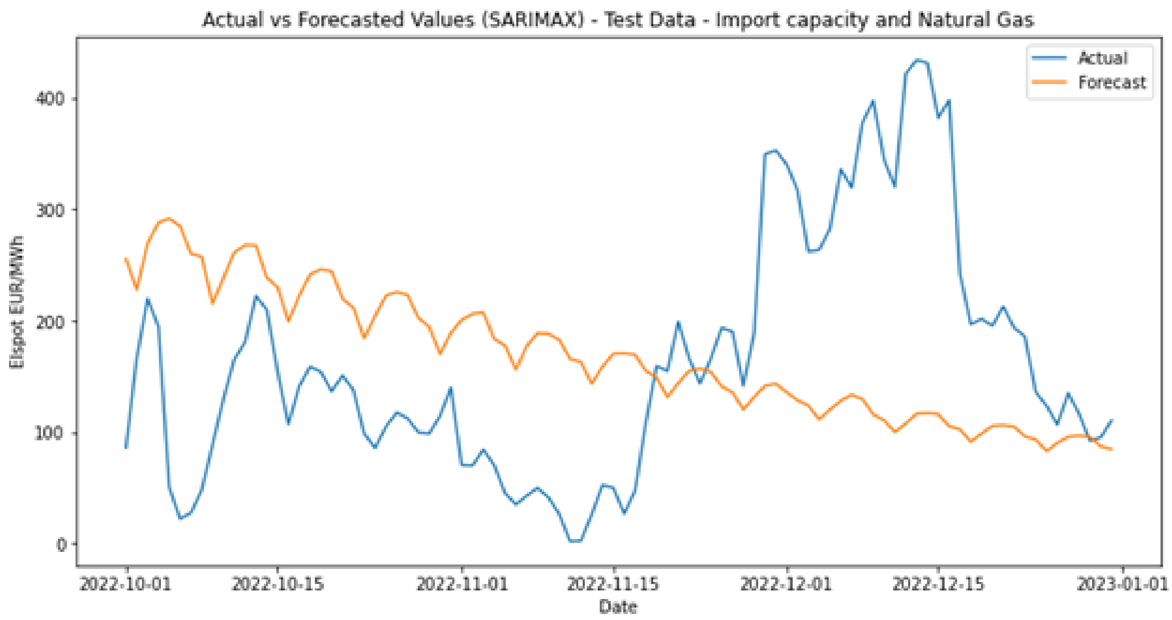


Figure 16. Actual natural gas prices and import capacity

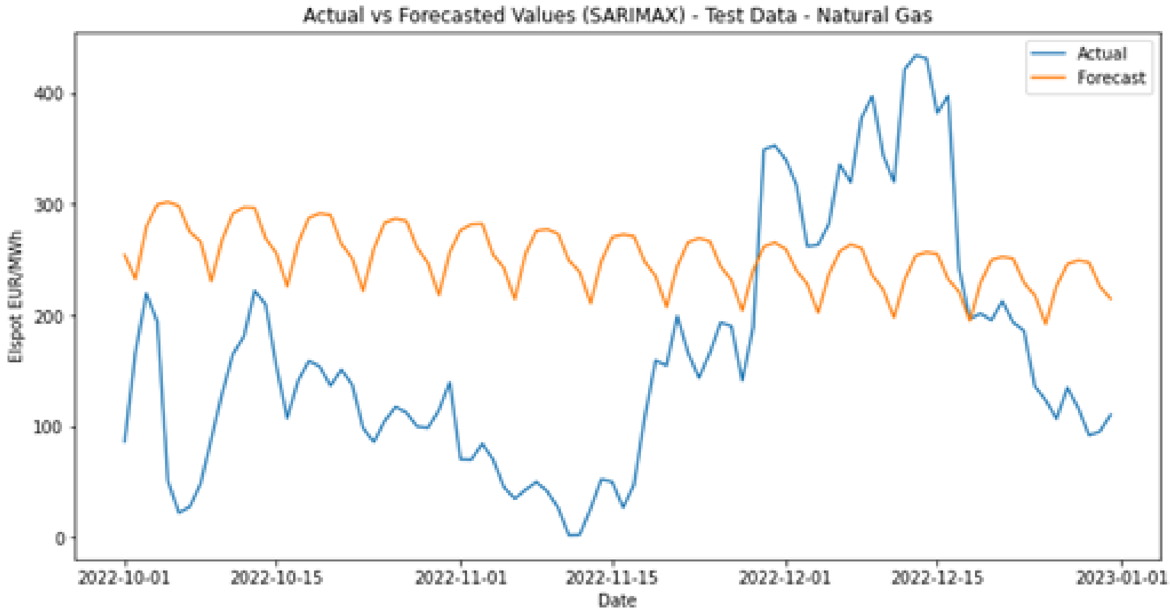


Figure 17. Natural gas prices effect on Elspot price (NO1 Bidding zone)

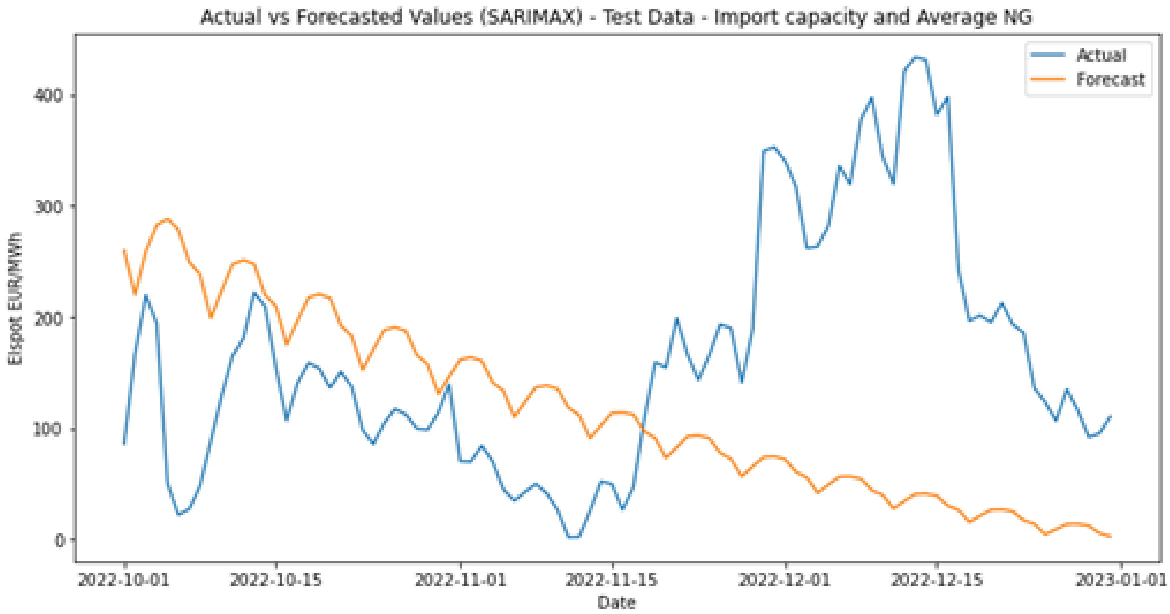


Figure 18. Impact of average natural gas price on Elspot price (NO1 Bidding zone)

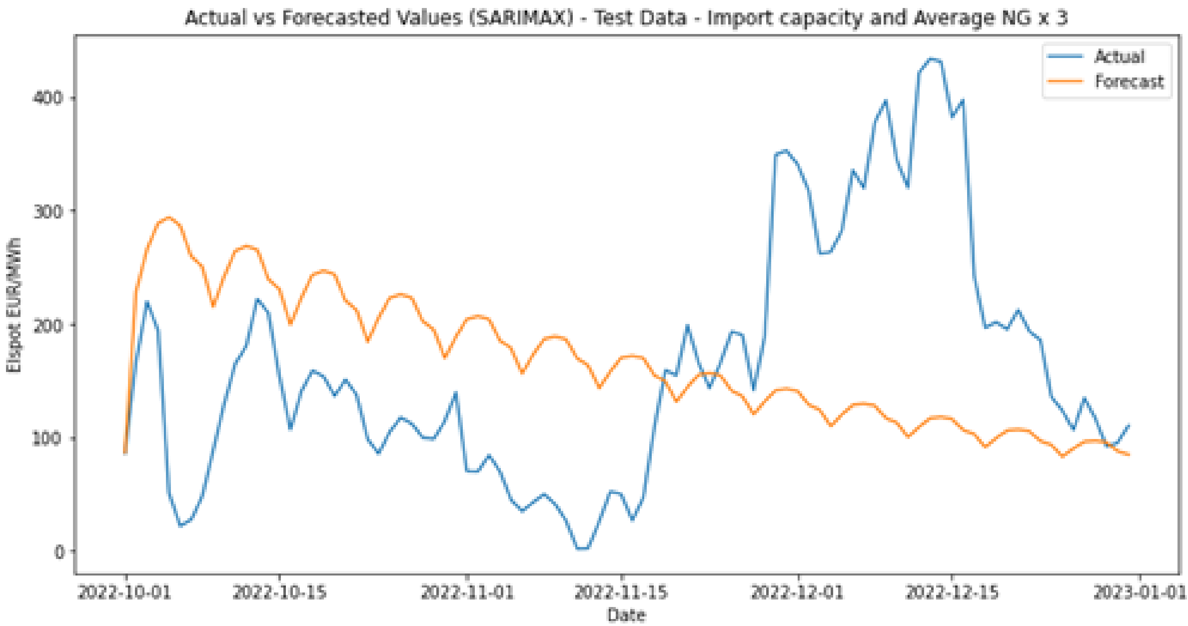


Figure 19. Scenario two: Impact of natural gas price, increased by a factor of three.

Scenario 2	Sub Scenarios for defined exogenous variables			
	Import capacity and Actual Natural Gas price	Natural Gas price	Import capacity and Average NG price since 2011-2022	Import capacity and Average NG price x 3
Average Actual Elspot (EUR/MWh)	164.69	164.69	164.69	164.69
Average Forecast Elspot (EUR/MWh)	168.01	non explanatory	117.08	166.58
Total Actual Profit (EUR)	39,414,491	39,414,491	39,414,491	39,414,491
Total Forecast Profit (EUR)	40,263,019	non explanatory	27,231,093	39,897,887

Table 9 Forecast average income for GKP (Natural Gas

Contrary to our expectations, the inclusion of natural gas as the only exogenous variable led to non-explanatory results. Consequently, we added the natural gas to the base model which has import capacity as the variable and this allowed us to model for the impact of natural gas. However, the result showed almost no impact on price. It became clear that the natural gas price should not be used because it reflected a period of high price volatility. The average price for the years 2011-2022 was used as the alternative to remove noise, outliers and reduce volatility. This led to an unsatisfactory result as the price is strongly converging toward zero (see Figure 19) and the use of the average was set aside.

Because this resulted in a modelling failure for this scenario, the impact of natural gas price on forecast profit for GKP cannot be commented.

6.2.3 Scenario Three: The Impact of Weather Variables

In the third scenario, we sought to investigate the extent to which the weather variables, specifically temperature and precipitation, potentially have on the Elspot price for the NO1 bidding zone and GKP profitability. This is important because of the important role of weather conditions on both energy demand and hydro production.

We incorporated 'Temperature' and 'Precipitation' as exogenous variables in the SARIMAX model and examined the resultant forecasts. The inclusion of these weather variables did not lead to any notable changes in the forecast average electricity price. This outcome suggests that, at least within the scope of our study and for the NO1 area, local weather variables may not have a significant impact on electricity prices.

The results contained in table 12. indicate that temperature and precipitation have no significant impact on the Elspot price or profit. Through this scenario, the forecast profit for GKP will not be significantly affected. See Table 12.

Looking at the column for only temperature and precipitation we can conclude that there is no explanatory or predictive power behind only the weather variables, which is also shown in figure 22. Comparing the tabulated values to the baseline forecasting model, the P95 simulation shows a less than 0.1% positive change in the profit and a less than 1.0% increase in profit. High temperatures in the fall and winter normally lower demand and higher precipitation should lead to an increase in hydropower production. These two effects combined would be expected to lower electricity prices. This is not evident. The P5 simulation shows a less than 2% increase in the average price and a 2.0% increase in profit. A cold and dry period should by contrast lead to higher electricity prices, which also is not forecasted in the result.

Scenario 3	Sub Scenarios for defined exogenous variables			
	Import capacity, temperature & precipitation	Temperature and precipitation	P95 - Warm/Wet	P05 - Cold/Dry
Average Actual Elspot (EUR/MWh)	164.69	164.69	164.69	164.69
Average Forecast Elspot (EUR/MWh)	166.99	non explanatory	166.15	167.70
Total Actual Profit (EUR)	39,414,491	39,414,491	39,414,491	39,414,491
Total Forecast Profit (EUR)	40,004,928	non explanatory	39,789,272	40,185,952

Table 10. Forecast average income for GKP (weather variables)

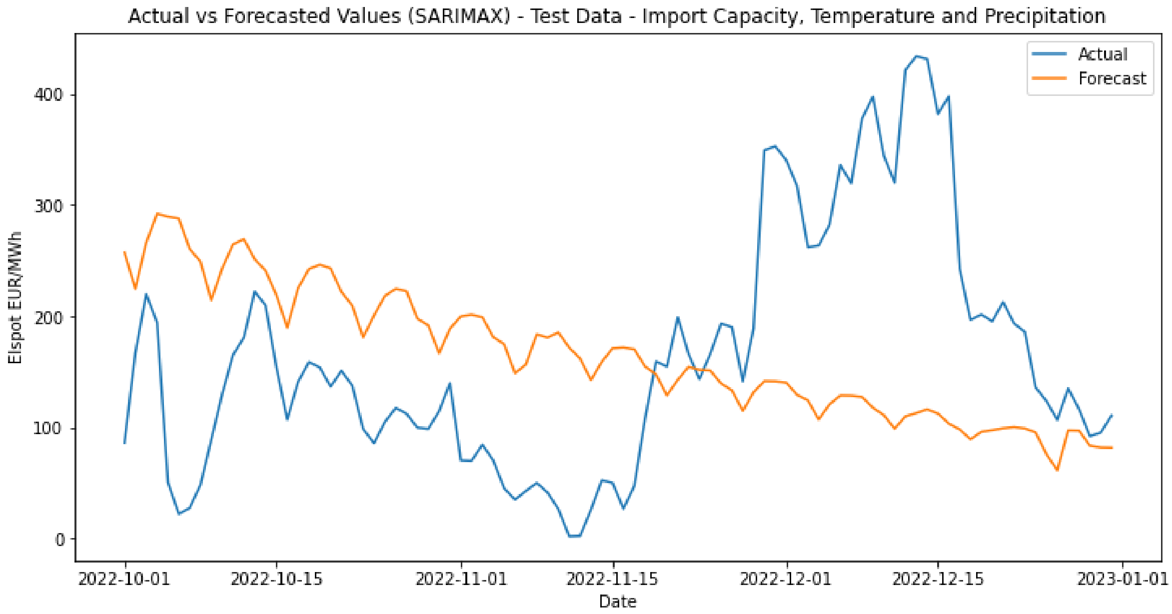


Figure 20. Impact of temperature and precipitation

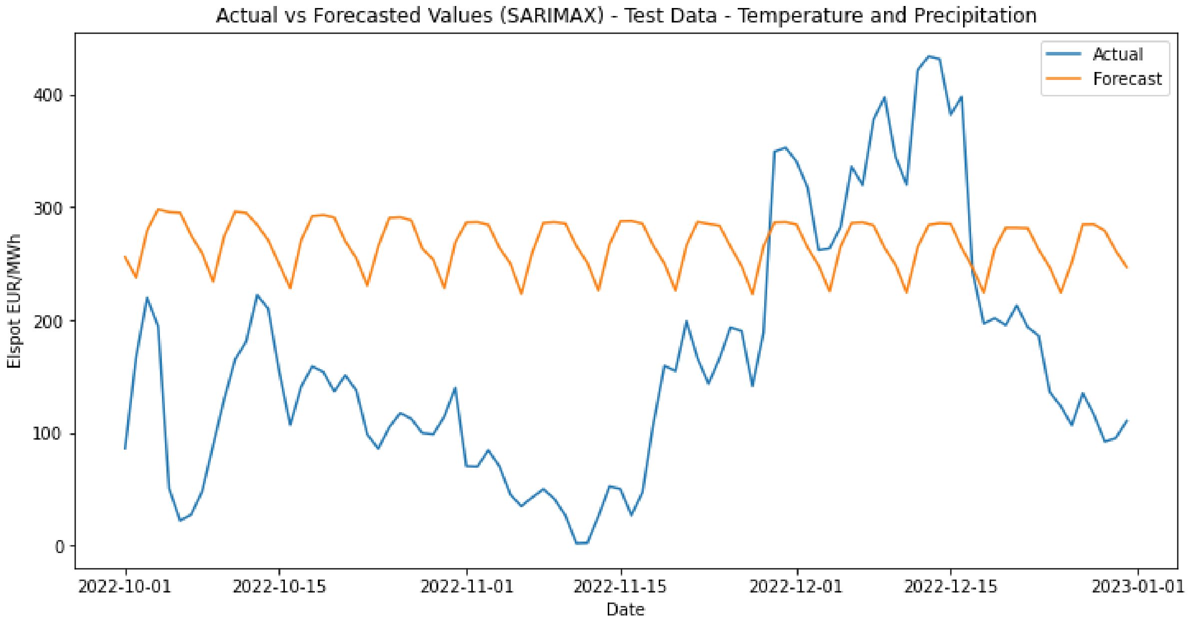


Figure 21. Temperature and precipitation isolated

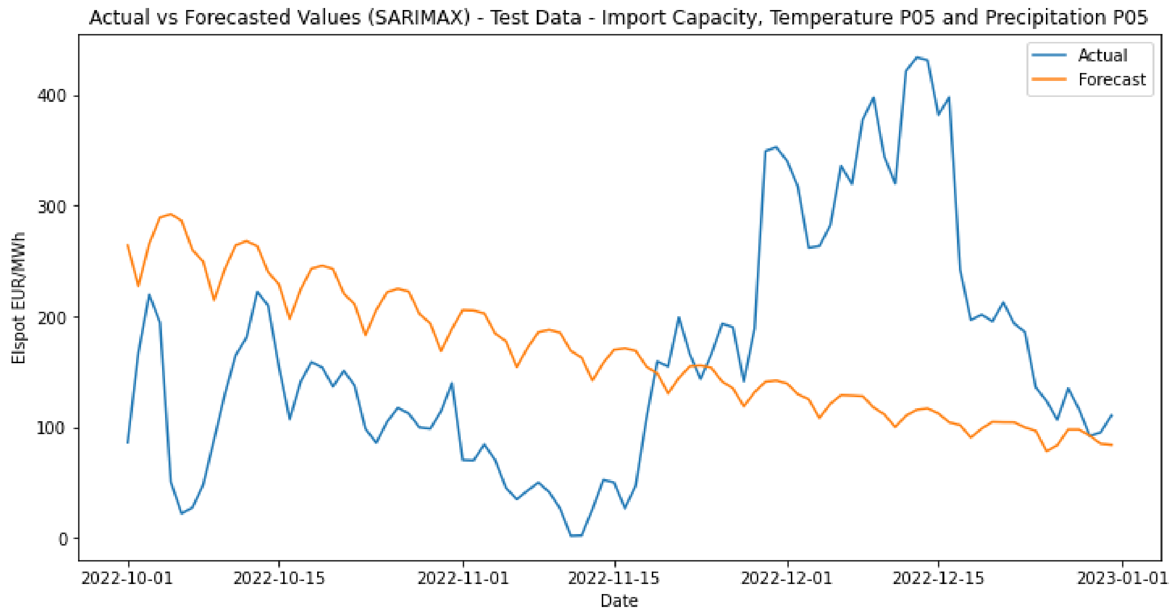


Figure 22. Very Cold/Dry weather conditions

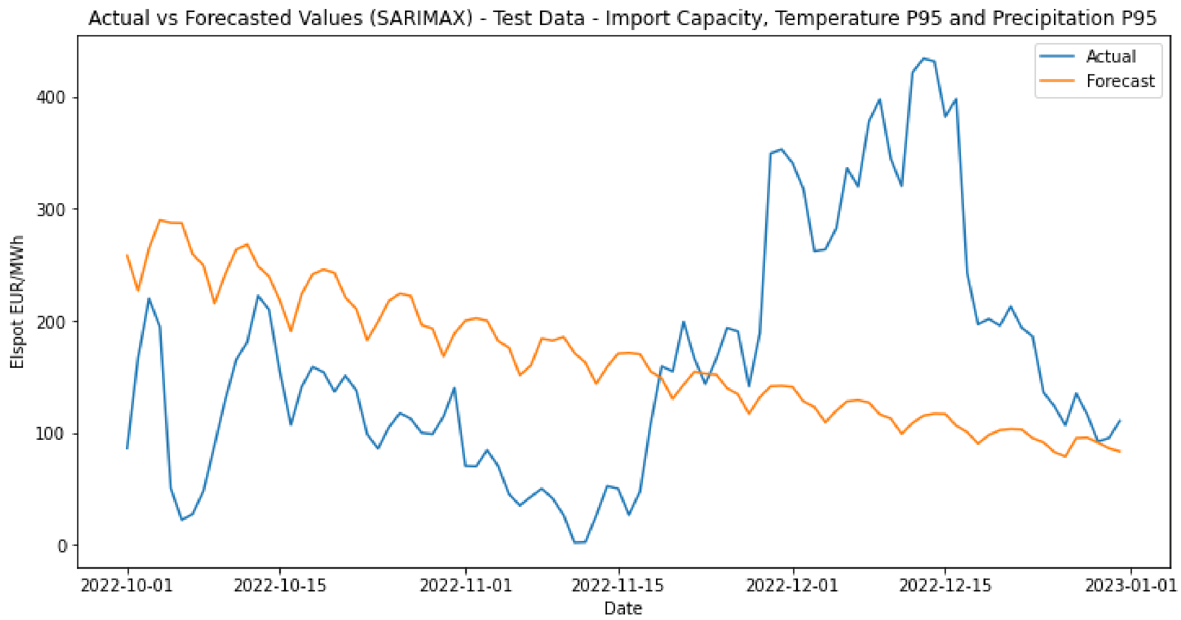


Figure 23. Very warm/wet weather conditions

It's important to consider the inherent complexities in modelling the relationship between weather variables and electricity prices. Precipitation and temperature are non-linear variables, meaning their impacts on electricity prices may not follow a straightforward or constant pattern. This makes them challenging to accurately capture using linear models such as SARIMAX. This could explain our result.

Furthermore, the impact of weather on electricity prices can be influenced by various factors, including regional energy mix, infrastructure, and demand patterns. As such, the lack of a significant impact in the NO1 area does not necessarily rule out the potential influence of weather variables in other regions or under different conditions.

In conclusion, our third scenario analysis provided valuable insights into the complexities of electricity price forecasting and highlighted the potential limitations of linear models in capturing non-linear relationships. Future research could explore more sophisticated modelling approaches, such as machine learning or non-linear time series models, to better account for these complexities and potentially uncover hidden patterns or relationships.

7 Discussion

In this chapter we will examine the results and discuss how they inform answering the research questions and our thesis. We will discuss each relevant variable we have analysed and explain whether or not the result contributes to answering the research question clearly or not and how. We signal now that our results are not on the whole explanative and this indicates a more complex connection between the different variables and underlying factors that are not captured or explained in the model.

Addressing Research Question 1: *"What effect would a doubling of the recent additional interconnector capacity of NordLink and North Sea Link between Norway and Europe have on NO1 spot price?"*

The recently commissioned interconnector capacity between Norway and Europe, specifically the NordLink and North Sea Link, appears to have a significant effect on the NO1 spot price. Our model's analysis, using the exogenous variable import capacity demonstrates a considerable sensitivity to changes in this variable. It suggests confirming this part of the thesis. This indicates that the cables could be a major contributor to the surge in electricity prices.

It is important to note that this scenario analysis is hypothetical and is based on the assumption that all other factors remain constant. In reality, electricity prices are influenced by a myriad of factors and their interactions. Nevertheless, the scenario provides valuable insight.

This finding can inform decision-making by stakeholders in the electricity market. For instance, it might suggest the need for careful consideration of strategies involving capacity import increases, given their potential to significantly increase electricity prices.

In both the period of time the model was trained and for the 3 months of forecast, gas price was highly influential on the marginal price for electricity in Europe. This is because gas fired power generation was often the marginal production technology during this period. Since the increase of export capacity would allow a lower price producer in Norway to increase supply to higher price area Europe, we could have expected increased price convergence. This would cause the Norwegian price to increase and the European price to fall. This is reflected in our results.

Extending the forecast period to six or twelve months and assessing the results could open up for longer term forecasting with increased accuracy. This would increase the methods utility for financial planning both in the parent and the county that rely on dividend income for certain investment portfolio funds.

Addressing Research Question 2: *"What effect does benchmark European natural gas price have on NO1 spot price?"*

Interestingly our exploration of the potential effects of natural gas prices yielded unexpected results. The average 11-year gas price was multiplied by three and modelled. This led to an outcome that was approximately same as base model and confirmed there was no significant correlation in our model. Increasing natural gas price had no effect when they were expected to have due to the price convergence mechanism with Europe and the marginal price of gas there being highly impacted by gas price in the period.

The inclusion of natural gas as a separate variable does not provide additional information that significantly alters the forecast (Figure 17). To understand this result would require more research and knowledge to be developed around the importance of careful variable selection in time-series forecasting. It suggests that the inclusion of additional variables may not always enhance the model and, in some cases, could even lead to redundancy if the impacts of these variables are already accounted for by existing factors in the model.

Upon reflection, the impact of natural gas price on electricity price for NO1 may already be encapsulated in import capacity. The correlation matrix shows a linear dependency, but the dependency is weak. It may be strongly non-linear and, in this case, other modelling techniques such as GARCH or machine learning models may be more appropriate choices.

While we would conclude from our results that benchmark European natural gas prices have no effect on NO1 spot price we question the applicability of this result.

Addressing Research Question 3: "*What effect does temperature or precipitation in the NO1 bidding zone have on NO1 spot price?"*

Looking at the weather variables for scenario three, the model shows that local weather variables had no significant impact in our forecast model. This is surprising since it is common knowledge that temperature affects demand, and that precipitation is a supply driver for hydroelectric power. These two variables are the fundamental principles of market-based price setting. However, as mentioned earlier the weather station SN18700 situated in the NO1 bidding zone may not capture the entire picture. Further, we can comment on the fact that weather variables are non-linear variables, meaning they don't directly affect the Elspot price, but rather through a series of more complex interactions, e.g., reservoir filling.

Another point to be made is reservoir filling. This for the NO1 bidding zone seem less relevant as run-of-river hydro production is the dominant technology in that area, thus making the precipitation variable possibly redundant for the model. We also know that there are no network constraints between NO1 and the adjacent bidding zones NO2 and NO5 in southern Norway and pricing converges. The biggest production capacity in Norway is located in the adjacent bidding zones NO2 and NO5 and are predominantly dominated by hydro-dam generation, because of this, the local weather variables in NO1 might not have such a big impact on spot price compared to the adjacent bidding zones local weather. This covers the supply side. On the other hand, Eastern Norway, where the NO1 bidding zone is located, is home to approximately half of the population from which a great amount of electrical power demand is sourced. As the temperature falls in the winter, demand for power increases. This strongly suggests that temperature, when isolated as a variable, should have had more of an impact on price than it did. However as previously mentioned it is a non-linear variable and this might be the explanation for not seeing this impact in our model. We conclude that temperature and precipitation in NO1 bidding zone do not impact spot price in NO1.

Addressing Research Question 4: "*Does Glomma Kraftproduksjon AS earn increased profit because any of temperature and precipitation in the NO1, gas prices in Europe and interconnector capacity to Europe are increased?"*

For the external factors modelled we found import capacity to be the only variable with any significant impact on NO1 spot price and consequently on profit for Glomma Kraftproduksjon AS. An increase in spot price for GKP increases income on an essentially fixed cost base. GKP must always be delighted when power prices rise as it will always improve their profitability compared to lower prices when no other drivers change.

As a comment, the annualised profit in 2022 was estimated to be 161 million Euro or 1,625 million kroner. We are confident in this number, but our research can only establish that the increase in interconnector capacity was a contributor.

7.1 Limitations and Future Research

While our model performed well in capturing the average electricity price, it's important to acknowledge its limitations. The SARIMAX model, being a linear model, may not fully capture the complexities and non-linear relationships inherent in electricity price data. This was evident in our attempt to model the impact of weather variables, which did not yield significant changes in the forecast.

Moreover, our model was specifically designed to forecast the average electricity price over a three-month period, and its performance may differ when applied to other forecasting tasks. Additionally, the model's reliance on past data assumes that future patterns will follow historical trends, which may not always hold true given the evolving nature of energy markets.

Looking forward, more sophisticated modelling techniques, such as machine learning or non-linear time series models, could be explored to better capture the complexities of electricity price data. Future research could also consider other potential exogenous variables or investigate the impacts of different forecasting horizons or regional contexts on the model's performance.

Our research contributes valuable insights into electricity price forecasting using a SARIMAX model. While there are inherent challenges and complexities in forecasting electricity prices, our model demonstrates a promising approach that balances accuracy, interpretability, and practicality. Our findings provide a solid foundation for further exploration and refinement of electricity price forecasting models, ultimately contributing to more informed and effective decision-making in the electricity market.

Due to uncontrollable factors such as precipitation and temperature, power producers often have to rely on market forces. Our model suggests that power cables become crucial in times of high gas prices, leading to higher marginal costs. As long as there's a need for import, this proves to be a beneficial situation for GKP, as they profit from the market being expensive or "out of balance."

8 Conclusion

The aim of the thesis was to see to what extent local factors of temperature, precipitation and external factors of interconnect capacity and natural gas prices drive the price of power in a specific region and the profitability of the run-of-river power producer in that region, Glomma Kraftproduksjon AS. Based on the development and use of a SARIMAX time series model and the subsequent analysis of the results, it can be concluded that interconnector capacity increases do play a role in increasing the power price and profitability of the producer.

We thought this was of interest in light of the recent fierce public debate on what to blame for the recent high price conditions and the much-shared view that publicly owned power companies were benefiting, while households and power cost sensitive businesses experienced hardship.

To answer our thesis, we required a modelling tool and method and we had a wide array of choices to choose from. The main factor for consideration was data access and data type. We required data from the competitive electricity markets, where data is typically available in time series with hourly sample periods. We had good access to this data through Nord Pool.

Commodity data was easily accessible from the EIKON database which was also available in time series but with different sample periods and not with spot price but futures prices.
We selected a seasonally adjusted autoregressive integrated moving average methodology. The SARIMAX model we understood would give us better interpretability for our purpose because it is excellent when adding several exogenous variables with seasonality.

The exogenous variables that were required to model the endogenous variable of power price were narrowed down to a few by the variable selection process, which included the use of a combination of analytical techniques and domain knowledge. We learnt that the SARIMAX model works well when the exogenous and endogenous variable (Elspot price) are linearly correlated but does not when those relationships are non-linear (for example weather variables) or where multicollinearity between the exogenous variables exists (for example Brent crude and Coal).

We expected to find strong relationships between the exogenous variables of temperature, precipitation, natural gas price and interconnector capacity (import and export) and spot price. As we progressed, we realized, using our domain knowledge, that the local variables for weather NO1 might have little impact on the NO1 price. This because of the dominance of hydropower dams and production capacity in the adjacent bidding zones and the lack of any transmission constraints causing full price convergence between the zones. Import interconnector capacity did have a strong impact on price in our model and this is what we expected. This was a success for the model and pleasing. We expected to see natural gas price changes in Europe strongly impact the NO1 price, however the SARIMAX model failed, converging to zero. More work was needed to resolve why.

In essence, our conclusion is that as long as we are part of a market characterized by high marginal costs, this pricing dynamic will continue to yield high revenues for GKP. Furthermore, the model does not effectively capture local factors like weather variables due to non-linearities. Notably, the majority of the production doesn't occur in NO1 but in the other price regions. Hence, the weather conditions in these regions play a more significant role as the price is formed across these bidding areas, ensuring free flow.

It was interesting to discover that GKP has very little influence over the price of its commodity or control over its profitability. As a low margin producer, it always benefits from selling in a market with higher marginal costs. The interconnectors and market integration with Europe are of great benefit to GKP as it offers big opportunities for this ‘as available’ producer to participate in the ‘on-demand’ marketplace.

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9 Appendix

Appendix A.1: VIF – Index – Checking for multicollinearity.

	Variable	VIF
0	const	153.296833
1	Wind	1.065472
2	Precipitation	1.043366
3	Temperature	2.112940
4	Reservoir Filling	1.648613
5	Brent Crude Oil	7.597966
6	Coal Prices	6.658229
7	Natural Gas	2.964893
8	Production (Norge)	3.150865
9	Consumption (Norge)	3.580073
10	Carbon Price	3.773427
11	Total Export flyt	2.067638
12	Total Import flyt	2.113273
13	Total capacity import	2.139082
14	Total capacity export	3.336030

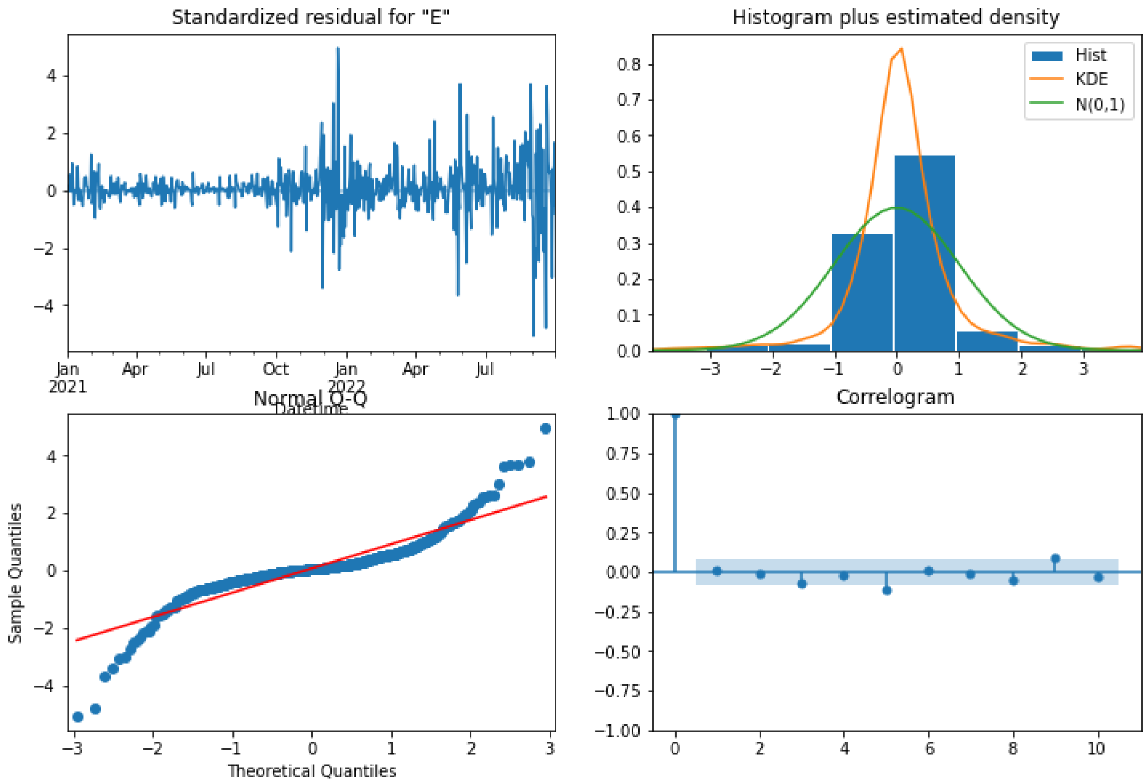
Appendix A.2: Summary table of correlation coefficients.

```
Correlation coefficients between Elspot and exogenous variables:
Wind                    -0.134716
Precipitation           -0.057440
Temperature              0.023699
Reservoir Filling        0.030553
Brent Crude Oil          0.541765
Coal Prices              0.748417
Natural Gas              0.729885
Production (Norge)      -0.081424
Consumption (Norge)     -0.117143
Carbon Price             0.521825
Total Export flyt       -0.217576
Total Import flyt        0.390664
Total capacity import    0.316639
Total capacity export    0.241809
Name: Elspot, dtype: float64
```

Appendix A.3: ADF test.

	Variable	ADF Statistic	p-value	Stationarity
0	Elspot	-3.2098	0.0194	Yes
1	Wind	-11.4833	0.0	Yes
2	Precipitation	-14.8534	0.0	Yes
3	Temperature	-2.0167	0.2793	No
4	Reservoir Filling	-2.2675	0.1827	No
5	Brent Crude Oil	-1.6409	0.4618	No
6	Coal Prices	-1.343	0.6093	No
7	Natural Gas	-2.7599	0.0642	No
8	Production (Norge)	-3.7226	0.0038	Yes
9	Consumption (Norge)	-3.3762	0.0118	Yes
10	Carbon Price	-1.6507	0.4567	No
11	Total Export flyt	-4.874	0.0	Yes
12	Total Import flyt	-5.8585	0.0	Yes
13	Total capacity import	-3.302	0.0148	Yes
14	Total capacity export	-2.2196	0.1992	No

Appendix A.4: Diagnostics of baseline model.



Appendix B.1: Baseline model results.

```
                                     SARIMAX Results                                      
==========================================================================================
Dep. Variable:                             Elspot   No. Observations:                  638
Model:             SARIMAX(1, 0, 2)x(1, 0, 2, 7)   Log Likelihood               -2941.490
Date:                            Tue, 16 May 2023   AIC                           5898.979
Time:                                    02:44:30   BIC                           5934.646
Sample:                                01-01-2021   HQIC                          5912.825
                                     - 09-30-2022                                         
Covariance Type:                              opg                                         
==========================================================================================
                             coef    std err          z      P>|z|      [0.025      0.975]
------------------------------------------------------------------------------------------
Total capacity import   5.109e-06      0.000      0.039      0.969      -0.000       0.000
ar.L1                      0.9779      0.007    130.973      0.000       0.963       0.993
ma.L1                     -0.0976      0.027     -3.617      0.000      -0.151      -0.045
ma.L2                     -0.1339      0.032     -4.194      0.000      -0.196      -0.071
ar.S.L7                    0.8918      0.052     17.060      0.000       0.789       0.994
ma.S.L7                   -0.7938      0.065    -12.134      0.000      -0.922      -0.666
ma.S.L14                   0.0724      0.037      1.977      0.048       0.001       0.144
sigma2                   777.7810     28.685     27.114      0.000     721.559     834.003
===================================================================================
Ljung-Box (L1) (Q):                   0.06   Jarque-Bera (JB):              2240.72
Prob(Q):                              0.81   Prob(JB):                         0.00
Heteroskedasticity (H):              16.44   Skew:                            -0.08
Prob(H) (two-sided):                  0.00   Kurtosis:                        12.18
===================================================================================

Warnings:
[1] Covariance matrix calculated using the outer product of gradients (complex-step).
```

Appendix B.2: Scenario One: Doubling of the NordLink and North Sea Link capacity.

```
                                     SARIMAX Results                                      
==========================================================================================
Dep. Variable:                             Elspot   No. Observations:                  638
Model:             SARIMAX(1, 0, 2)x(1, 0, 2, 7)   Log Likelihood               -2939.177
Date:                            Mon, 22 May 2023   AIC                           5894.354
Time:                                    19:33:37   BIC                           5930.020
Sample:                                01-01-2021   HQIC                          5908.200
                                     - 09-30-2022                                         
Covariance Type:                              opg                                         
=================================================================================
                    coef    std err          z      P>|z|      [0.025      0.975]
---------------------------------------------------------------------------------
Import 2800Mwh -1.517e-05   7.03e-05     -0.216      0.829      -0.000       0.000
ar.L1             0.9962      0.004    232.893      0.000       0.988       1.005
ma.L1            -0.1571      0.022     -7.036      0.000      -0.201      -0.113
ma.L2            -0.0388      0.025     -1.541      0.123      -0.088       0.011
ar.S.L7           0.9854      0.015     67.912      0.000       0.957       1.014
ma.S.L7          -0.9387      0.030    -31.394      0.000      -0.997      -0.880
ma.S.L14          0.1381      0.025      5.529      0.000       0.089       0.187
sigma2          637.7658     18.578     34.329      0.000     601.354     674.178
===================================================================================
Ljung-Box (L1) (Q):                   1.93   Jarque-Bera (JB):              2212.13
Prob(Q):                              0.16   Prob(JB):                         0.00
Heteroskedasticity (H):              15.58   Skew:                            -0.34
Prob(H) (two-sided):                  0.00   Kurtosis:                        12.10
===================================================================================

Warnings:
[1] Covariance matrix calculated using the outer product of gradients (complex-step).
```

Appendix B.3: Scenario Two: Increase of Natural Gas by a factor of three.

```
                                      SARIMAX Results
=======================================================================================
Dep. Variable:                          Elspot   No. Observations:                  638
Model:             SARIMAX(1, 0, 2)x(1, 0, 2, 7)   Log Likelihood               -2945.363
Date:                         Mon, 22 May 2023   AIC                           5908.726
Time:                                 22:03:12   BIC                           5948.851
Sample:                             01-01-2021   HQIC                          5924.303
                                  - 09-30-2022
Covariance Type:                           opg
===========================================================================================
                              coef    std err          z      P>|z|      [0.025      0.975]
-------------------------------------------------------------------------------------------
Total capacity import    6.172e-06      0.000      0.047      0.963      -0.000       0.000
Gj.snitt NG 2011-2021 x 3  -2.8346      0.348     -8.136      0.000      -3.517      -2.152
ar.L1                       0.9779      0.007    130.928      0.000       0.963       0.993
ma.L1                      -0.1012      0.027     -3.742      0.000      -0.154      -0.048
ma.L2                      -0.1401      0.032     -4.374      0.000      -0.203      -0.077
ar.S.L7                     0.8918      0.051     17.325      0.000       0.791       0.993
ma.S.L7                    -0.7936      0.065    -12.272      0.000      -0.920      -0.667
ma.S.L14                    0.0756      0.037      2.067      0.039       0.004       0.147
sigma2                    778.1100     28.687     27.124      0.000     721.884     834.336
===================================================================================
Ljung-Box (L1) (Q):                   0.07   Jarque-Bera (JB):              2131.96
Prob(Q):                              0.80   Prob(JB):                         0.00
Heteroskedasticity (H):              11.45   Skew:                            -0.14
Prob(H) (two-sided):                  0.00   Kurtosis:                        11.95
===================================================================================

Warnings:
[1] Covariance matrix calculated using the outer product of gradients (complex-step).
```

Appendix B.4: Simulating a hot/wet period – P95.

```
                                      SARIMAX Results
=======================================================================================
Dep. Variable:                          Elspot   No. Observations:                  638
Model:             SARIMAX(1, 0, 2)x(1, 0, 2, 7)   Log Likelihood               -2938.933
Date:                         Mon, 22 May 2023   AIC                           5897.865
Time:                                 22:04:30   BIC                           5942.448
Sample:                             01-01-2021   HQIC                          5915.173
                                  - 09-30-2022
Covariance Type:                           opg
============================================================================================
                              coef    std err          z      P>|z|      [0.025      0.975]
--------------------------------------------------------------------------------------------
Total capacity import    2.676e-06      0.000      0.020      0.984      -0.000       0.000
Precipitation Scenario P95 -0.3741      0.188     -1.992      0.046      -0.742      -0.006
Temperature P95            -0.3585      0.574     -0.624      0.533      -1.484       0.767
ar.L1                       0.9781      0.008    128.498      0.000       0.963       0.993
ma.L1                      -0.0906      0.028     -3.244      0.001      -0.145      -0.036
ma.L2                      -0.1357      0.033     -4.151      0.000      -0.200      -0.072
ar.S.L7                     0.8922      0.053     16.834      0.000       0.788       0.996
ma.S.L7                    -0.7889      0.066    -11.978      0.000      -0.918      -0.660
ma.S.L14                    0.0718      0.038      1.878      0.060      -0.003       0.147
sigma2                    779.2737     30.489     25.560      0.000     719.517     839.030
===================================================================================
Ljung-Box (L1) (Q):                   0.04   Jarque-Bera (JB):              2157.68
Prob(Q):                              0.84   Prob(JB):                         0.00
Heteroskedasticity (H):              15.18   Skew:                            -0.03
Prob(H) (two-sided):                  0.00   Kurtosis:                        12.01
===================================================================================

Warnings:
[1] Covariance matrix calculated using the outer product of gradients (complex-step).
```

Appendix B.4: Simulating a cold/dry period – P05.

```
                                     SARIMAX Results
==========================================================================================
Dep. Variable:                         Elspot   No. Observations:                  638
Model:             SARIMAX(1, 0, 2)x(1, 0, 2, 7)   Log Likelihood               -2938.933
Date:                        Mon, 22 May 2023   AIC                           5897.865
Time:                                22:05:04   BIC                           5942.448
Sample:                            01-01-2021   HQIC                          5915.173
                                 - 09-30-2022
Covariance Type:                          opg
==========================================================================================
                             coef    std err          z      P>|z|      [0.025      0.975]
------------------------------------------------------------------------------------------
Total capacity import   2.676e-06      0.000      0.020      0.984      -0.000       0.000
Precipitation P05         -0.3741      0.188     -1.992      0.046      -0.742      -0.006
Temperature P05           -0.3585      0.574     -0.624      0.533      -1.484       0.767
ar.L1                      0.9781      0.008    128.498      0.000       0.963       0.993
ma.L1                     -0.0906      0.028     -3.244      0.001      -0.145      -0.036
ma.L2                     -0.1357      0.033     -4.151      0.000      -0.200      -0.072
ar.S.L7                    0.8922      0.053     16.834      0.000       0.788       0.996
ma.S.L7                   -0.7889      0.066    -11.978      0.000      -0.918      -0.660
ma.S.L14                   0.0718      0.038      1.878      0.060      -0.003       0.147
sigma2                   779.2737     30.489     25.560      0.000     719.517     839.030
===================================================================================
Ljung-Box (L1) (Q):                   0.04   Jarque-Bera (JB):              2157.67
Prob(Q):                              0.84   Prob(JB):                         0.00
Heteroskedasticity (H):              15.18   Skew:                            -0.03
Prob(H) (two-sided):                  0.00   Kurtosis:                        12.01
===================================================================================

Warnings:
[1] Covariance matrix calculated using the outer product of gradients (complex-step).
```

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