NTNU – Trondheim
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Science and Technology

Profitability of a Hydro Power Producer Bidding in Multiple Markets

An Analysis of the Specific Case of
Tokke-Vinje Hydro Power System

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Problem Description

The EU has set ambitious goals to reduce the CO2 emissions. An important part of this is to increase the share of renewable sources in the energy mix, in particular wind- and solar power. These are heavily weather dependent causing intermittent generation. Consequently, challenges related to the power balance develop.

Traditionally, most of the power that is traded at the power exchange Nord Pool Spot is traded in the day-ahead market. Large variations in the production will however increase the need for balancing services that are activated closer to real time.

The increasing need for balancing services create a major business-opportunity for Norwegian hydro power producers. Hydro power is flexible with the ability to mitigate the consequences from fluctuating renewable generation. The objective of this work is to investigate the profitability a hydro power producer may achieve by participating in the balancing and capacity market. This is done by using a prototype optimization model for production planning in AMPL.

This Master's thesis is a continuation of a specialization project that was finished in December 2014. The thesis will be based on the same foundation as the project and several improvements and model extensions will be done. This includes improvement of input data and implementation of the capacity market and a risk reducing strategy.

Supervisor: Magnus Korpås, NTNU
Co-supervisor: Marte Fodstad, SINTEF Energy Research

Preface

This is the Master's thesis in a 5-year Master of Science degree at the Norwegian University of Science and Technology (NTNU), Department of Electric Power Engineering. The work is part of the research project "Integrating Balancing Markets in Hydro Power Scheduling Methods" funded by the Norwegian Research Council and industry partners and is a collaboration between the university and SINTEF Energy Research.

Several people have been involved in the project and supported our work. We are sincerely grateful for the professional supervision Magnus Korpås has provided throughout the past year. He has done more than is required of his role and has contributed with helpful and encouraging discussions. We also wish to thank our co-supervisor Marte Fodstad that has shared valuable knowledge about the optimization model used in this report. Arild L. Henden has also been helpful and patient in teaching us the program ProdRisk.

We would also like to express our gratitude to Hege Brende and Even Lillefoss Haugen at Norwegian Hydropower Centre for helping us see our thesis in a wider perspective and introducing us to the hydro power industry.

Finally, a special thanks to our fellow master students at our office at NTNU. Their ability to create a good working environment, even when they were all stressed out of their minds finishing their theses, has been indispensable.

Caroline Rasmussen and Jakob Boye Ørbæk Hansen
Trondheim, June 2015

Executive Summary

The main topic of this project has been to study the production scheduling of a hydro power producer exposed to the day-ahead, balancing and capacity market. The objective was to find what profit the producer may achieve by strategically bid in the above mentioned markets.

A prototype model that undertakes this task has been developed by SINTEF Energy Research as a part of their project "Integrating Balancing Markets in Hydro Power Scheduling Methods". It is a multi-stage, multi-scenario, short-term deterministic model programmed in AMPL. SINTEF Energy Research and Statkraft have provided reservoir and inflow data. The water values have been calculated using ProdRisk. Since the model is a prototype which is under development, a substantial portion of the work has been related to structure and implement proper input data such as PQ-curves, inflow and price scenarios.

To examine the potential profit a producer may gain by participating in the balancing market, the model has been run with and without the balancing market included in the simulation. The simulations have shown that a hydro power producer increases the expected income by participating in the balancing market. The key findings are summarized in the table below, where the percentages are compared with the original income when bidding in the day-ahead market only.

Increased income per day	Week 1	Week 14	Week 27	Week 44
Absolute [kEUR]	20.72	20.22	7.74	9.00
As % of original income	5.24%	5.86%	0.65%	2.35%

The model has been run with both Nordic and German day-ahead prices. The German day-ahead prices lead to even greater increase in profits when including the balancing market, constituting 59.61% of the original income. The simulations have also been done with higher price volatility, which resulted in a further increase in profits.

Separate simulations have been done with different amounts of reserved capacity in the capacity market, with measures to reduce risk and with implementation to enforce acceptable reservoir behavior, respectively. The possibility of gathering profits from the capacity market proved to be limited. However, this conclusion is based on the prices that have been seen since the market was introduced in 2014 and may change if the prices rise.

Sammendrag

Hovedtemaet for dette prosjektet har vært å studere produksjonsplanleggingen til en vannkraftprodusent som opererer i day-ahead-, balanse- og kapasitetsmarkedet. Formålet var å undersøke om en produsent kan øke fortjenesten ved å by strategisk i disse markedene.

En prototypemodell har blitt utviklet av SINTEF Energi som en del av prosjektet "Integrating Balancing Markets in Hydro Power Scheduling Methods". Modellen er en flersteg, multi-scenario, deterministisk korttidsmodell, programmert i AMPL. Reservoar- og tilsigsdata har blitt gjort tilgjengelig av SINTEF Energi AS og Statkraft. Vannverdiene ble beregnet i ProdRisk. En konsekvens av at modellen er under utvikling er at en stor mengde arbeid har vært knyttet til å tilpasse og implementere input data, som blant annet PQ-kurver, tilsig og prisscenarier.

Det ble foretatt simuleringer med og uten regulerkraftmarkedet inkludert for å undersøke hvor mye lønnsomheten potensielt kan økes ved å delta i dette markedet. Simuleringene viste at den forventede inntekten økte dersom produsenten deltok i regulerkraftmarkedet. Hovedfunnene er oppsummert i tabellen nedenfor. Verdiene oppgitt i prosent er sammenlignet med den forventede inntekten ved kun å delta i spotmarkedet.

Increased income per day	Week 1	Week 14	Week 27	Week 44
Absolute [kEUR]	20.72	20.22	7.74	9.00
As % of original income	5.24%	5.86%	0.65%	2.35%

Simuleringer ble gjort med både nordiske og tyske priser. Med tyske priser økte den forventede inntekten desto mer da regulerkraftmarkedet ble inkludert. Økningen utgjorde 59.61% av inntekten ved kun å delta i spotmarkedet. Simuleringer ble også utført med økning i prisvolatilitet, noe som førte til at den forventede inntekten økte ytterligere.

Kapasitetsmarkedet har blitt implementert i modellen der simuleringer med ulike mengder allokert kapasitet er utført. Muligheten for å øke profitten ved å delta i dette markedet viste seg å være lav. Siden kapasitetsmarkedet ble introdusert i 2014, er denne konklusjonen basert på priser fra sesongen 2014/2015. Det er mulig det vil lønne seg i fremtiden dersom prisene for reservert kapasitet endrer seg.

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1 Introduction

Hydro power plays an important role in a power system focusing on mitigation and adaption to climate change. The penetration of renewable energy sources like wind and solar has increased significantly in Europe throughout the last years. These energy sources are heavily weather dependent causing intermittent generation. Consequently, challenges related to the power balance develop. Norwegian hydro power is flexible with the ability to mitigate the consequences from fluctuating renewable generation. The increasing need for balancing services create a major business-opportunity for Norwegian hydro power producers.

The objective of this work is to investigate the profitability a hydro power producer may achieve by participating in several short-term markets, emphasizing the balancing market. This will be done using a prototype production planning model programmed in A Mathematical Programming Language (AMPL), provided by SINTEF Energy Research. It is a multi-stage, multi-scenario deterministic model that describes a single hydro power producer bidding in the day-ahead and balancing market.

A consequence of the model being under development is that the procedure of finding and implementing input data is not given and input data has to be adjusted to the appropriate format. Thus, in-depth work will be performed to generate proper input data from a realistic case into the model.

It is important to be critical to the results as the model has extensive simplifications of real-world conditions and may not take all relevant factors into account when calculating the optimal solution. Based on the results, strengths and weaknesses with the model will therefore be evaluated.

Structurally, the project thesis is composed of three main parts: A literature review, model representation and optimization results. Section 2 represents a theoretical background of the relevant themes for the optimization problem such as today's power market, the changing energy sector and hydro power methodologies. Section 3 describes the functionality of the optimization model, while the specific case study that will be examined will be described in section 5, including the work related to input data. Section 6 and 7 covers results and analysis of the case, respectively.

2 Methodologies and Background

2.1 The Nordic Power System

This section focuses on the Nordic power system. The Nordic countries are interconnected with the Baltic countries Estonia, Lithuania and Latvia, creating the Nordic-Baltic power system. These countries are synchronized and the power system is connected with continental Europe through HVDC-cables.

The Nordic power system is dominated by hydro- and thermal power production, with an increasing amount of wind power. As figure 1 illustrates, the countries have different production mix. The different energy resources complement each other. E.g. Norway export power in wet years and import in dry years, while Denmark export when there are a lot of wind and import when it is less windy. Hydro power constitutes more than half of the total Nordic power production. Furthermore, 60 per cent of the Norwegian and Swedish hydro power is reservoir hydro. Thus, the Nordic power system in total has high flexibility as a result of the large amount of hydro power [1].

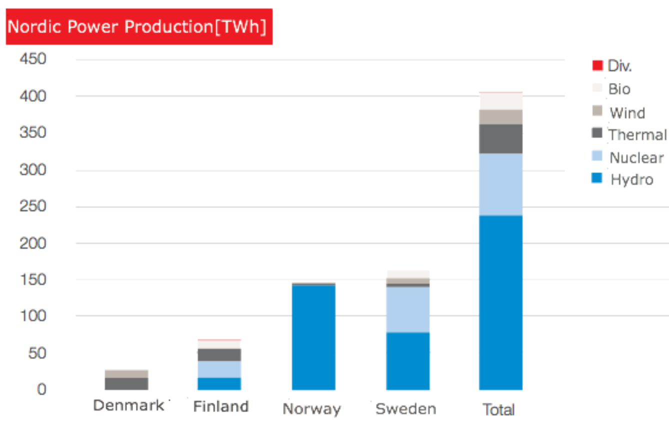

Figure 1: Total power production and production mix in the Nordic countries in 2012 [1].

The characteristics of hydro power make it desirable to participate in the balancing market. These characteristics include short response times, ability to black start, cost-efficient flexibility and energy storage potential [3]. With these characteristics hydro power can enhance stability and security of supply, hence facilitate the integration of intermittent renewable energy by participating at the balancing market. Hydro power is expected to play an increasingly important role in the future as the power system is changing. This will be further discussed in the following section.

2.2 The Changing European Power Sector

It is expected that the European power market is going to change remarkably the coming years as a result of climate concerns and market efficiency promotion. The next sections will look into the two main European power market trends: increased market coupling and renewable energy penetration. Subsequently, the impact on Norwegian hydro power producers will be discussed.

2.2.1 Renewable Energy Penetration

The European Union's (EU) ambitious climate and energy policy has been dominant throughout the last decade. The climate and energy target is '20-20-20', i.e. achieving 20% reduction in EU greenhouse gas emissions, 20% improvement in the EU energy efficiency and raising the renewable resource share to 20% of the total EU power generation within 2020 [4]. Figure 2 illustrates the expected change in the European generation mix.

Installed capacity [GW]

Country	2010	EU202020
Germany	135	237
The UK	77	94
The Netherlands	27	44
Poland	33	41
Sweden	35	41
Norway	31	37
Finland	17	23
Denmark	12	15
Balticum	8	14

Explanation

- Nuclear
- Fossil fuels
- Renewables (excl. hydro)
- Hydro
- Other

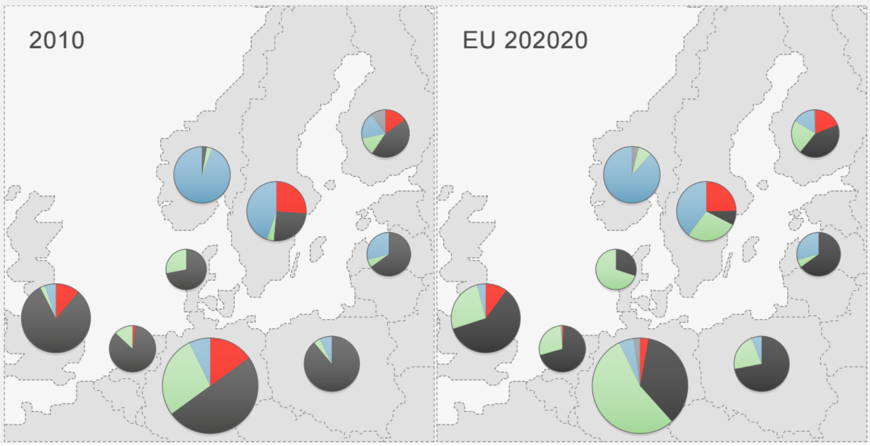

Figure 2: Total installed production capacity in Europe in 2010 and expected in 2020 and the distribution between different technologies [1].

As the figures illustrate, the renewable energy share is predicted to increase substantially. Furthermore, EU has a goal of reducing the greenhouse gas emissions with 80 per cent within 2050. Investments in wind and solar energy are expected to contribute considerably to achieve these goals [1]. These energy resources are weather dependent and can not be regulated to meet demand of a power system. Thus, issues related to maintaining the grid power balance are likely to occur.

2.2.2 Market Coupling

EU has a goal of moving towards one common interconnected power system in order to deal with intermittency issues posed by renewable generation, enable diversity of suppliers and enable competition in the European market [5]. Thus, a common European power system enhances liquidity, efficiency and maximization of total social surplus. The transmission capacity from the Northern Europe is expected to increase with 5000-6000MW by 2030 [1]. Figure 3 illustrates the projected capacity development from the synchronous area within year 2020.

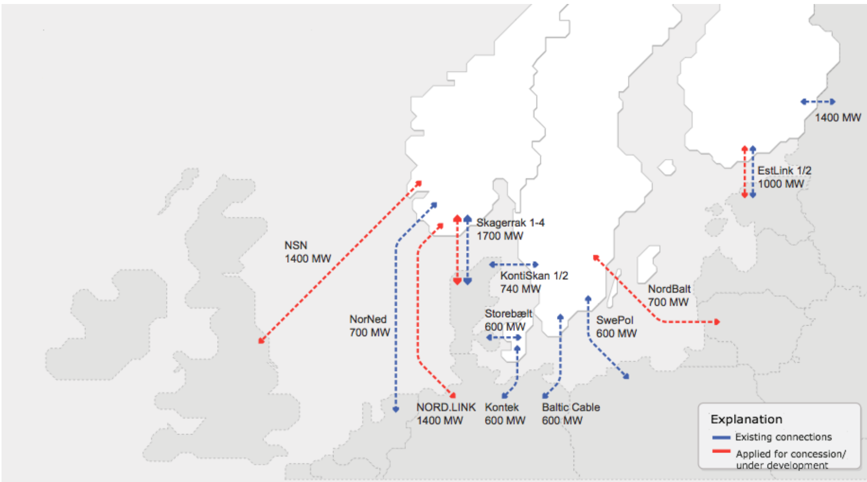

Figure 3: Expected interconnectors from the synchronous area in 2020 [1].

As of today, the integrated European day-ahead markets consist of 19 countries, covering 85% of the European power consumption [6]. Even though the existing market integration is well advanced in day-ahead markets, it is necessary to harmonize regional rules and market platforms further to converge the markets and thus achieve a common EU approach [7].

2.2.3 A Need for Generation Flexibility

The high penetration levels of intermittent renewable energy combined with a greater level of interconnectors will change the properties of the existing power system. Firstly, issues related to maintaining the power balance increase the demand for flexible power production with the ability to up- and down-regulate rapidly.

"To incorporate these intermittent sources, a power market needs to be flexible enough to accommodate short-term forecasts and quick turn transactions. This flexibility is particularly valuable with respect to wind energy, where wind forecast uncertainty decreases from 15% to 4% in the last 24 hours before actual generation (from observed data in Germany). Therefore, intraday and balancing markets need to be adjusted to make full use of the flexibility of the transmission system and the different generation technologies to effectively respond to increased uncertainty." [8]

Secondly, more cross-border transmission capacity enables the TSOs to co-operate with the power exchange companies to establish a common intra-day market. This gives the participants the opportunity to deal with the uncertainty related to power generation. The technological differences between the Nordic and European power system create dissimilarities in the cost of balancing services. Thus, trade of balancing services is likely to be more profitable in the future. The European energy trends create great business opportunities to Norwegian hydro power producers, as the energy source has low costs with high regulating abilities.

2.3 The Nord Pool Market

This section presents the various power markets disposable for Norwegian participants with emphasis on the regulating market. It is only the physical market solutions offered at Nord Pool Spot that is described, as the financial market is considered to be outside the scope of work in this project. The physical market consists of a day-ahead-, intra-day- and balancing energy market. In addition, the market contains a capacity market. These will be referred to as DA, ID, BM and RKOM, respectively. These will be briefly described in the following sub-sections. The information about these markets are provided by [1] and [9].

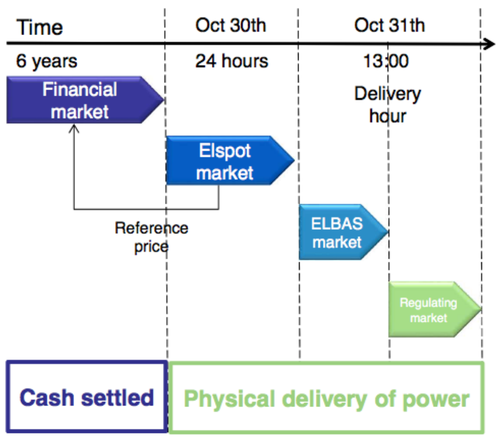

Figure 4: An illustration of the financial- and physical market in Norway.

2.3.1 The Day-Ahead Market

The day-ahead spot market, Elspot, is the dominant market where most of the trading occurs. Elspot functions as an auction where producers and consumers send their hourly purchase and sale bids before noon the day ahead. When the market closes, Nord Pool Spot arrange the bids into supply and demand bid curves for each hour and the market prices are decided by the intersection between the two curves, as illustrated in figure 5. All participants will receive this market price, regardless of their submitted bids, and they are obligated to deliver/purchase their volume commitments the next day. The obligated volume is set by interpolating between the nearest price-volume bids.

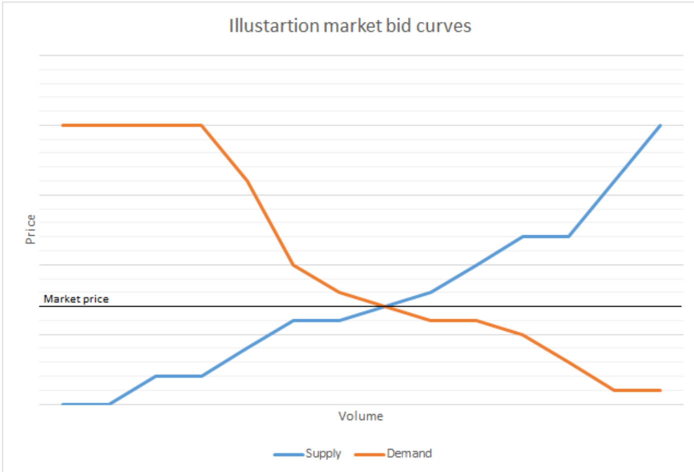

Figure 5: An illustration of the energy market bid curves.

Due to bottlenecks, the Nordic countries are divided into 15 bidding areas that may have different area prices depending on the demand, supply and transmission capacity. In 2013, 493 TWh was traded through Nord Pool Spot. This represented 84% of the total power exchange.

2.3.2 The Intra-Day Market

When the DA has cleared at 12:00 CET and the market prices for the next day has been calculated, the intra-day market Elbas opens at 14:00 CET covering the Nordic and Baltic region as well as Germany.

Elbas is a continuous market that supplements Elspot and contributes to secure the power balance. Imbalance between demand and supply may occur after the market clearing because of unforeseen endeavors such as power plant shut down or deviation from weather forecasts. This might cause more or less power production than expected. By trading at Elbas, the market participants are allowed to adjust their bids until one hour before real time in order to create the necessary balance between supply and demand. In 2013, 4.2 TWh was traded on Elbas. This constituted 0.85% of the total power traded on Nord Pool Spot that year.

2.3.3 The Balancing Market

When the ID has closed one hour before operation time, the TSOs have the responsibility to maintain the power balance at instantaneous production in their respective area. Since the TSO does not have production resources of its own, it has to acquire balancing services in terms of reserve capacity and balancing energy. In the following paragraphs the Norwegian balancing market will be emphasized.

The balancing market consists of three main control principles: primary-, secondary-, and tertiary regulation reserves. The goal is to maintain the system frequency at 50Hz in the Nordic synchronous system. Both primary and secondary reserves are automatically activated, while tertiary reserve is manually activated by the TSO. The secondary reserves is used to restore primary control if the imbalance lasts for minutes, and the tertiary reserve is a backup to the secondary reserve if the frequency deviation still exists. This relationship is illustrated in Figure 6.

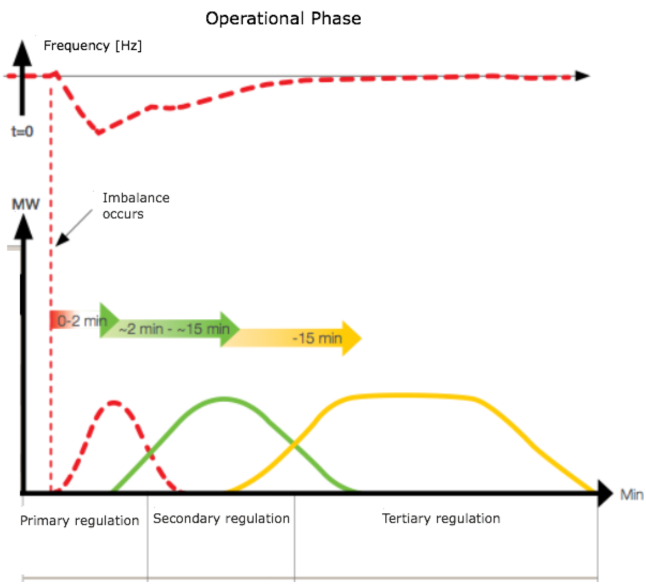

Figure 6: Illustration of activation sequence of different types of reserves [1].

When the balancing market is discussed in this report, it is the tertiary reserve that it is referred to. A common Nordic balancing market was introduced in 2002 as a result of collaboration between Nordic TSOs. In this market, balancing services can be used to handle imbalances anywhere in the Nordic power system, given that the transmission capacity is sufficient. The main participators that offer balancing resources are producers and large consumers that are able to manually respond on 15 minutes notice and deliver steady power for a minimum of one hour. The participants bid price and volume that will be activated based on price in merit-order. The market price is determined after the delivery hour, based on all bids that are activated.

The Nordic regulating marked had a total volume of 1.66 TWh traded in year 2013, which represented 0.34 per cent of the Elspot volume [10]. As discussed in Section 2.2.3, the changing power system creates business opportunities to hydro power producers.

2.3.4 The Capacity Market (RKOM)

There is a capacity market within the Norwegian balancing market that ensures adequate up-regulation resources by using options. The need for reserve capacity has mainly been related to the winter months (October to April). This market is better known as *Regulerkraftopsjonsmarkedet* (RKOM) within the country. Participants are paid to guarantee that they participate in the balancing market if required with power production or consumption disconnection. The options traded in RKOM last for a week or a season, and the sets of conditions are equal in both these markets [11].

Capacity can be reserved in RKOM either on a seasonal or weekly basis. Capacities traded in RKOM-season are reserved for the entire season, while there are two different types of RKOM-week options: RKOM-H and RKOM-B. These are split into RKOM-day (00:00 to 05:00) and RKOM-night (05:00 to 24:00). In RKOM-H bids are accepted for the entire day or the entire night. Offers in RKOM-B can be limited in duration and include a period of up to 8 hours with no reserved capacity. The RKOM-B bid price is reduced for increasing flexibility according to rules applied by Statnett.

The deadline for bids in RKOM-week is Friday at noon for the following week, Monday through Sunday. Available market data for RKOM-week can be found in Appendix D.

2.4 Hydro Power Scheduling

The theory presented is this section puts the optimization model of the paper in context with the hydro power scheduling hierarchy. The information is based on lectures and literature from [2].

The objective for a hydro power producer is to maximize profits in a deregulated market where the prices are unknown. The production scheduling is a challenging task because the physical structures are complex, there are large variations in resource availability and the time horizons are long. In addition, the uncertainty related to price, inflow and demand make the scheduling even more complicated. Therefore, the hydro power scheduling problem is divided into a scheduling hierarchy consisting of long-term, seasonal and short-term scheduling, see Figure 7. This report will focus on the short-term scheduling. The scheduling and coupling methods in the hierarchy will be described in the following sub-sections.

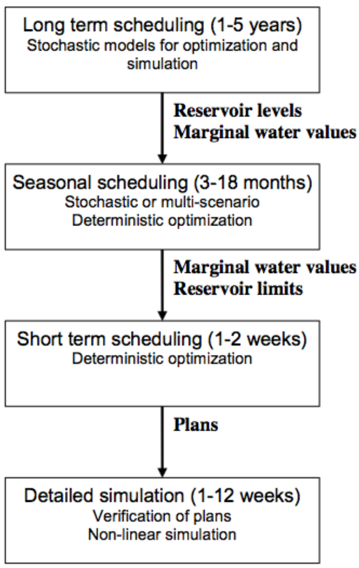

Figure 7: Scheduling hierarchy [2].

2.4.1 Long-Term Scheduling

The long-term scheduling is typically done in the EFI's Multi-Area Power-market Simulator (EMPS) model. The objective is to ensure optimal utilization of the resources in order to maximize profits. The inflow, renewable generation, demand and other relevant factors are modelled as stochastic parameters. This way the model takes many possible scenarios into account, including the effect of extreme events with low probability but comprehensive consequences.

The long-term model is divided into two phases; strategy phase and a simulation phase. In the former phase the water values are calculated for aggregated local sub areas. The division of areas is based on the hydrological characteristics, transmission constraints, ownership considerations and the total river system. The second phase simulates a detailed dispatch of the system up to 10 years ahead with weekly time resolutions. The water balance between the reservoirs is used to give end reservoir restrictions to the seasonal modeling.

2.4.2 Seasonal Scheduling

The objective for the seasonal model is to maximize revenues from each water system formulated as a deterministic problem. The seasonal scheduling couples long-term with short-term scheduling, as these models require different levels of details. The seasonal scheduling is based on the reservoir drawdown model where the total production from each aggregated area is distributed between available reservoirs and plants. Physical and judicial constraints are implemented, giving a more detailed description of the reservoirs. This makes it possible to calculate water values for each reservoir within one year horizon and a weekly time step. The long-term modeling is linked either at the autumn in the filling season, or at the end of the winter before the snow starts melting. The choice of coupling method depends on the degree of regulation of the reservoirs.

2.4.3 Short-Term Scheduling

Short-term optimization has the goal of finding the actual operation for the coming days and hours. The optimal production is achieved when the marginal cost of producing one more unit of energy equals the market price, in EUR/MWh [12]. The mathematical formulation below illustrates a simplified version of the maximization criterion, where the short-term profit and the expected future value of the water left in the reservoir are added together. The underlying assumption is that there is perfect competition, thus the market participants are price-takers.

$$Max[\sum_{t\in\mathcal{T}}(p_t * (q_{st} - q_{pt}) - c_{start,t} - c_{penatly,t}) + W_{\mathcal{T}}] \tag{1}$$

$\mathcal{T}$ -	Number of time-steps
p_t -	Price at time step t [EUR/MWh]
q_{st} -	Quantity sold at time step t [MWh]
q_{pt} -	Quantity purchased at time step t [MWh]
$c_{start,t}$ -	Start-up costs for starting a unit at time step t [EUR]. Including a binary variable representing on/off
$W_{\mathcal{T}}$ -	Final end- reservoir value at time t=$\mathcal{T}$ [m^3]

2.4.4 Water Values and Coupling

When determining the optimal hydro power production, it is essential to consider the handling of reservoir level as equation 1 states. The value of the water stored in the reservoir is seen as an opportunity cost, and is defined as the expected value of the stored kWh of water [13]. It is an expected value because the value is dependent on uncertain factors such as future market prices, demand and inflow.

The water value of the unused water left in each reservoir at the end of the model horizon depends on the water level in all other reservoirs. This means that the water value for a reservoir is not a linear function, but a multidimensional problem. It is very difficult to formulate an accurate function describing this and even if it was done, the non-linearities would make it very hard to solve.

To work around this, water value cuts can be calculated from a sample of reservoir levels in the respective magazines. Each sample contains a set of reservoir levels, the corresponding water value and slope of the water value of each reservoir. The slope indicates how much the value will change per unit increase in the reservoir level. By using these cuts as restrictions for the water value, the problem becomes linear with an acceptably low inaccuracy.

It is intuitively clear that the water value function is a concave and increasing function. It is increasing because more water in a reservoir never will reduce future income. It is concave because an extra unit of water in the reservoir will have less marginal value the fuller the reservoir is.

2.5 Modelling Uncertainty

When performing hydro power scheduling, the two most important points of uncertainty are the market prices and the inflow.

2.5.1 Prices

A critical uncertainty to power producers is related to the market prices of electricity, as the clearing prices in both the DA and BM are unknown at the time of bidding. Furthermore, the market prices are expected to be influenced by the change in the European power system (see section 2.2). It is important to investigate the price affections in order to mitigate the price unpredictability, even though some uncertainty will remain.

To determine how a hydro power producer should utilize the balancing markets efficiently with the introduction of more intermittent generation, it is important to make reasonable assumptions on how such generations will affect the market prices. Since intermittent power cannot be stored efficiently with today's technology, it has to be produced whenever the resource is available, e.g. when the wind is blowing or the sun is shining. An intermittent power producer is therefore dependent on an accurate forecast of the weather for the next day to be able to estimate the power he will be able to deliver. If the forecast then turns out to be wrong, the producer has to trade in the intra-day or balancing market. As a consequence, it is reasonable to assume that a larger share of intermittent power generation will cause the balancing market price to have higher volatility and deviate more from the spot price.

When generating future price scenarios, several factors have to be analyzed in order to generate realistic prices. Some of the most important global drivers are affected by numerous external forecasts. According to Statkraft [14], a reasonable way to generate price scenarios is by gather and analyze information from a large set of well-known sources such as IEA, EU and IPCC. This information combined with well-thought assumptions is used to formulate estimates of critical global drivers such as fuel prices, CO2 prices and policies, technology costs and the macroeconomic situation. One must accept that unforeseen market events may occur, and it can be hard to incorporate the outcome of them. There will always be uncertainty related to the forecast as the future is unknown. However, it is important to make as reasonable assessments as possible to investigate realistic future profitability of hydro power.

2.5.2 Inflow

When undertaking long term and seasonal scheduling, accurate predictions of the inflow to the reservoirs are important for good results. To be able to find an optimal solution of how much water to take out of the reservoirs, one needs to know how much runs into them. In short term scheduling, however, the inflow plays a very minor role if the reservoir is large. The inflow during one day is typically a lot smaller than the reservoir capacity. As a consequence, a normal inflow will not lead to a significant increase in the reservoir level in the cause of just one day, and therefore not affect the optimal dispatch notably. An exception is during extreme flooding, when small reservoirs in particular might produce or even spill more than otherwise optimal.

The inflow is in general more important for smaller reservoirs, since the inflow will be larger compared to the capacity. In this case, the producer will have less freedom to make decisions based on the market, but be more confined to physical restrictions. In run-of-river plants the producer can only produce when there is inflow.

Since hydro power has a dominant position in the Nordic market, the prices are strongly correlated with the inflow [2]. The prices will therefore to some extent reflect the expected future inflow, which is more important than the actual inflow for the particular day of scheduling.

2.6 Software Tools

The optimization model of the river system is implemented in the commercial software A Mathematical Programming Language (AMPL). The algebraic modeling language is capable to describe and solve high-complexity optimization problems and schedule-type problems. The problems supported by AMPL include linear, nonlinear, mixed-integer and constraint programming. An important advantage with AMPL is the syntax similarity between the modelling language and the mathematical notation of optimization problems. The optimization software package CPLEX is used to solve the optimization problems. It is the most widely used large-scale solver because of its efficiency and robustness [15].

ProdRisk [16] is a software tool that is utilized for the calculation of input data in the model. The model developed by SINTEF is used for long- and mid-term hydropower optimization and simulation. The calculation is based on stochastic dual dynamic programming. The results from ProdRisk simulations are utilized as water value cuts that create consistency between inflow- and price scenarios generated in the long-term scheduling. Further explanations about the concept of seasonal scheduling and water value cuts are found in Section 2.4.2 and 2.4.4. The generated values are used as input data in the model implemented in AMPL.

Matlab is another software tool that has been utilized to generate and analyze input data related to the considered system. It is a high-level programming language that is used mostly for numerical computation and visualization [17]. The processed data has been used as decision support when evaluating the results, and relevant values have been implemented as input data in both AMPL and ProdRisk.

3 Model Description

To examine the role of the regulating power market today and in the future, a multi-stage, multi-scenario, short-term deterministic model is used. The optimization problem has been implemented and solved in AMPL. The model is developed as a part of the SINTEF project 'Integrating Balancing Markets in Hydro Power Scheduling Methods' and is written by Marte Fodstad and Arild Helseth. The model description in this section is based on [18] and [10].

The model is still to be considered a prototype and is under development as this report is written. The model is not yet integrated with other commercial software, which means that data gathered from some sources has to be modified to fit the input format. The modifications made will be further discussed in Section 5.2.

It considers a power producer who bids into the DA and BM. Based on scenarios of different reservoir inflows and market prices, the model optimizes the utilization of a hydro power system in order to maximize the sum of the profit within the model horizon and the future value of the unused water. One day is modeled at the time. The day is split into discrete time periods, the length of which is decided in the input data. The model documentation assumes an hourly resolution (24 time periods per day), but any resolution could be chosen.

The model does not take transmission costs into account and long-term commitments are considered fixed. This means that the uncertainty in this model is related to reservoir inflow and market prices only.

The functionality of the model is described in the following sections. The full mathematical model description can be found in Appendix A, where equations referred to can be found.

3.1 Overview

A hydro power plant consists of a reservoir, a number of generators and no more than one pump. The set $\mathcal{R}$ contains all the reservoirs and the generators connected to reservoir $r \in \mathcal{R}$ are gathered in the set $\mathcal{G}_r$. The set $\mathcal{G} = \cup_{r \in \mathcal{R}} \mathcal{G}_r$ is the combined set of all generators across all reservoirs.

The water flows and levels (except the inflows, which are parameters) are decision variables and are denoted q. The superscript of these indicates which kind of flow they represent: V is the reservoir level, R denotes released water from the reservoir, D discharge through the generator, B bypass and S spillage.

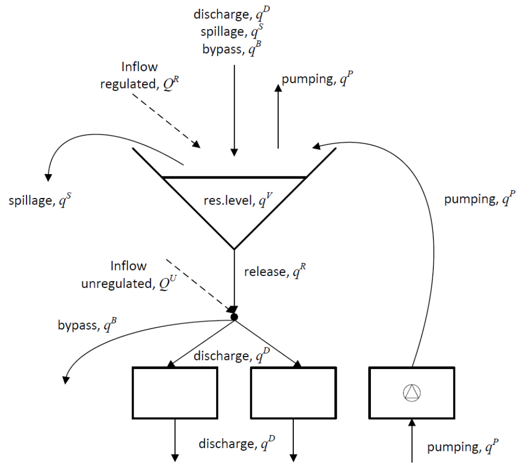

Figure 8: A hydro power unit with a reservoir, two generators and a pump. Solid lines are flows (decision variables) and spotted lines are input parameters [10].

3.2 Objective

The objective of the optimization is to maximize total profits. The income is the sum of the future value of the unused water (A.4), the value of the spinning state relative to the original state (A.5) and the income from the day-ahead and balancing markets (A.6 and A.7). The spillage cost (A.1), the startup cost (A.2) and the operation cost of thermal generation (A.3) are subtracted.

3.3 Stages

The optimization is done in three stages. The first stage is to bid in the DA. In the second stage, the DA is cleared and bids are accepted to the BM. In the last stage, the BM is cleared, imbalance settled and the optimal physical dispatch is found. Non-anticipativity constraints are added so that scenarios linked to the same node at a stage must have the same solution in this stage.

3.4 Water-to-Energy Calculations

The accurate function describing the generated electric of a hydro power generator is:

$$w = 9.81 \cdot 10^-3 E^{Turb}(h(q), q^D) E^{Gen} q^D h(q) \qquad (2)$$

E^{Turb} and E^{Gen} are turbine and generator efficiencies, q^D is the discharged water flowing through the turbine, q represents all flows and reservoir levels in play and $h(q)$ is the head function, including height difference and friction losses. This equation is complex and non-linear and some assumptions are made to simplify. Since the model horizon typically is one day, the head is considered constant. It is also assumed that each generator is independent, which means that they do not share tunnels or penstocks. The generated power is then modelled as a concave, piecewise linear function of the discharge. This linear curve is referred to as the PQ-curve. Section 5.2.2 describes the concept of PQ-curves further.

3.5 Water Value Implementation

The water value calculations are implemented in the model by using so called cuts. Every cut consist of a set of reservoir level, the total value of the water in all the reservoirs combined and the marginal water value in each reservoir. The marginal water value indicates how much the total water value will change per unit increase in the reservoir level. This way the model takes into account the fact that the water value in each reservoir is dependent on each other. Further description of water values is found in Section 2.4.4.

Since larger reservoirs will dominate the total water value, only the change in water value from the first to the last time period is added to the objective function. I.e. the water value of the initial conditions, U^0, is subtracted from the water value at the end of the planning horizon. U^0 is calculated before the simulation. Equation A.10 shows the mathematical formulation of the water value cuts.

3.6 Reservoir Balances, Ramping and Discharge Rates

The water balance in each reservoir is described by Equation A.8. It simply states that the volume in the reservoir after a time period is equal to the volume at the start of the period plus the sum of all flows into and out of the reservoir during the period. Equation A.9 describes the mass balance between the reservoir and the generator. It states that the total discharge runnig through the generators has to equal the sum of the released water from the reservoir and the unregulated inflow, minus the water that does not flow through the generators (the bypass).

There are limits to the ramping rates of each reservoir, i.e. how fast the volume of the reservoir is allowed to change. These limits are given as a fraction of the total reservoir capacity per hour. The ramping of the reservoir should ideally restrict the changes in the water surface height above sea level, which is not necessarily proportional to the volume. To simplify the implementation, the values used are therefore approximations to the change in water surface level with respect to reservoir volume. There are similar limits for the ramping of discharge, given in m^3 per hour. The reservoir and discharge ramping rates are implemented in the model through Equation A.12 and A.13, respectively.

3.7 Cost of Spillage

The cost of spilling water is normally only the lost value of the water not flowing through the turbine. Large spillages may however cause damage that the producer will have to pay for. The cost of this damage is denoted c_{rts}^{Spill} and is assumed to be a linear function of the amount of spilled water above the lower limit $\overline{Q}_r^S$. The rate of the cost per amount of spilled water is denoted C_r^{Spill}.

3.8 Start up Cost

Although the start up costs of a hydro power generator is normally small, it should be taken into account to ensure accurate distribution of production. The start up cost is denoted C_g^{Start} and is added to the objective function every time a generator is started through equation A.24.

3.9 Time Lag

The water that flows out of the reservoirs may end up in a downstream reservoir at some later time. The sets $\mathcal{R}_r^D$, $\mathcal{R}_r^S$ and $\mathcal{R}_r^B$ contains the reservoirs who's discharge, spillage and bypass, respectively, flows into reservoir r. The time the water spends flowing from one reservoir to another is captured by sets $\mathcal{T}_{\hat{r}t}^D$, $\mathcal{T}_{\hat{r}t}^S$ and $\mathcal{T}_{\hat{r}t}^B$. An element in e.g. $\mathcal{T}_{\hat{r}t}^D$ will be the time period t when discharge from reservoir $\hat{r}$ that was released in time period $\hat{t}$ ends up in the downstream reservoir. The time it takes for the water to travel from an upstream to a downstream reservoir is $T_{\hat{r}}^{D,Lag}$. T^L is the length of each time period. The equation used to calculate $T_{\hat{r}}^{D,Lag}$ is:

$$\mathcal{T}_{\hat{r}t}^{B} = \{\hat{t} \in \mathcal{T} : t - 1 < \hat{t} - \frac{1}{2} + \frac{T_{\hat{r}}^{D,Lag}}{T^L} \leq t\} \tag{3}$$

3.10 Markets

The power markets are handled according to the rules of Nord Pool Spot, see Section 2.3.

The Day Ahead Market

The bid curves are constructed by a number of price/volume-pairs and linear between these points. While the producer in reality is allowed to decide both price and volume, the prices are pre-determined in the input data, and the model only decides on the volumes. The volumes allocated in the DA are described by A.26 (delivery) and A.27 (purchase). Equations A.28 and A.29 ensure bid curve monotony.

The Balancing Market

The BM is treated in the same way as the DA, with the exception that the bid curves are sets of discrete price points. This means that each bid is either entirely accepted or rejected. The volumes allocated in the BM are described by A.30 (delivery) and A.31 (purchase). Equations A.32 and A.33 ensure bid curve monotony.

3.11 Notes

Some hydro power plants include pumps and the model is designed to be able to handle this. There are however no pumps in the system that is being examined here, and the functionality connected to pumps are therefore not described. Some additional market functionality has also been disabled to reduce complexity. This includes e.g. fixed production delivery (mandatory production) and purchase in the DA.

3.12 Model Assumptions

There are mainly two assumptions in the model that one should be aware of. Firstly, the model assumes that the producer is a price taker. This means that there are no interactions between the producer and the market and the producer decisions do not affect the market price in any of the markets. This is a reasonable assumption for a small producer relative to the total production in the area.

The power system that will be examined in this thesis is Tokke-Vinje, see Section 5, which is a rather large system. The total capacity is 990.4 MW, which means that the potential production is almost 24 GWh per day. The system produce power in the NO2-area, which in 2014 had an average daily production of 138.7 GWh. The peak during the winter 2014/2015 was close to 210 GWh per day [19]. This means that the Tokke-Vinje system can produce around 17% of the total supplied power on an average day and 11% during peaks.

No data on historical production for the isolated Tokke-Vinje system was available. Hence, it is not possible to accurately verify whether or not the results in this thesis deviate from a realistic production plan. It was therefore not possible to evaluate the results with respect to the price taker assumption.

The second assumption that is made is that the producer is risk neutral. The producer will act based on expected revenues regardless of the risk involved. In real life, the producer will weigh the expected revenues against the possibility of reducing the risk of ending up in situations with considerably worse results. This risk will vary depending on input data. An alternative way to handle risk will therefore be examined in Section 4.3.

4 Model Modifications

The model has been improved by adding new features to the implementation. This section describes the weaknesses with the model and the implementations that will strengthen them.

4.1 Implementation of RKOM

The RKOM is a capacity market that is cleared before the period of planning starts. The data from Statnett in Appendix D shows that there is currently no RKOM trade for the night hours, thus the capacity will be reserved in RKOM-day only. See Section 2.3.4 for explanation of the RKOM.

All capacities are reserved in the RKOM-H. The RKOM-B allows more flexibility, but at a lower price. To utilize the flexibility one would need to let the model decide the optimal way to reserve capacity throughout the hours, within the rules of RKOM-B and with different price levels as input. This would have required extensive implementation work and could increase computational time significantly. The RKOM-B was therefore excluded in this thesis.

As only RKOM-H was implemented in the model, the reserved capacity in the RKOM was determined beforehand as an input parameter. The market was implemented as two restrictions based on this capacity, which are shown in Equation 4 and 5. The regulation capacity, X_t^{RKOM}, measured in MW/h, is reserved in the DA so that the allocated volume in the DA, y_{ts}^{DA+}, is set to be lower than the total production capacity, X^{Max}, minus X_t^{RKOM}. In addition, the up-regulation volume in the BM, y_{ts}^{BM+}, is set to be greater or equal to X_t^{RKOM} in every hour the BM price is higher than the DA price. Hence, the reserved capacity will be activated for the entire hour whenever there is need for up regulation.

$$y_{ts}^{DA+} \leq X^{Max} - X_t^{RKOM}, \quad t \in \mathcal{T}, s \in \mathcal{S} \tag{4}$$

$$y_{ts}^{BM+} \geq X_t^{RKOM}, \quad t \in \mathcal{T}, s \in \mathcal{S}, \tilde{P}_{ts}^{BM} \geq \tilde{P}_{ts}^{DA} \tag{5}$$

No income from the RKOM is added to the objective function. Instead, the results from reserving different capacities are intended to be compared with the results without any reserved capacity. The total losses of reserving capacity compared to not participating in the RKOM can then be found. This can be used to calculate the price per reserved MW/h needed to break even, that will be further discussed in Section 7.2.1.

4.2 Flows and Reservoir Levels

In the original hydro power formulation, the observed behavior of the flow between the reservoirs seemed unrealistic. Huge amounts of water were transported as spillage or bypass from reservoir 4 to reservoir 5, which was caused by imprecise water values. Errors in the waterways were also discovered. The observed flows were unreasonable because it should not be possible to spill water unless the reservoir is full. Furthermore, huge amounts of spillage may damage the river system. Spillage should not be profitable, but rather a last resort if the inflow is large at high reservoir levels.

In order to deal with this challenge, several improvements that will affect the river flow were implemented in the model. Firstly, the waterways between the reservoirs were updated. The system is a simplified version of the real system; therefore, some reservoirs are aggregated reservoirs in the model. Because of this, some of the waterways did not accurately represent the reality. The updated waterways are shown in Figure 10.

Another improvement is that the water values were readjusted in order to create consistency between the reservoirs. This was a very important and comprehensive process that is described in detail in Section 5.2.4.

Extensions of the implemented model constraints were necessary in order to force the optimization to generate realistic results. The following sections will describe these implementations further. Section 4.2.1 describes the improvements regarding spillage and Section 4.2.2 the improvements of reservoir levels.

4.2.1 Allowing Spillage Under Certain Conditions Only

The initial results showed that the model could allow spillage even when it was practically unreasonable or physically impossible. In reality, spillage will only occur if the reservoir is full and the release from the reservoir is at its maximum. To incorporate this in the model, an additional binary variable, δ^{Spill}, was added. This variable should be set to zero only when spillage is allowed and limit spillage to zero otherwise. The following restrictions were added to the model.

$$q^S_{rts} \leq \overline{Q}^V_r * (1 - \delta^{Spill}), \quad r \in \mathcal{R}, t \in \mathcal{T}, s \in \mathcal{S} \tag{6}$$

$$\delta^{Spill} \geq \frac{\overline{Q}^V_r - q^S_{rts}}{\overline{Q}^V_r}, \quad r \in \mathcal{R}, t \in \mathcal{T}, s \in \mathcal{S} \tag{7}$$

$$\delta^{Spill} \geq \frac{\overline{Q}_r^R - q_{rts}^R}{\overline{Q}_r^R}, \quad r \in \mathcal{R}, t \in \mathcal{T}, s \in \mathcal{S} \tag{8}$$

Equation 6 limits spillage to zero if $\delta^{Spill} = 1$, otherwise to the maximum reservoir volume to make the restriction redundant if spillage is allowed. Equation 7 and 8 force $\delta^{Spill} = 1$ unless the reservoir is full and release is at maximum, respectively.

4.2.2 Penalty Functions

Penalty functions are used for various purposes in optimization. The concept is to choose a target value or boundary for one or more variables and apply a cost of deviating from this target value.

Penalty functions were introduced because the results from the initial results showed that the behavior of some of the reservoirs were unrealistic. Some reservoirs would be completely depleted at the end of the planning horizon and others completely filled. While some of these problems were gone as the water values and waterways were improved, the problems were not entirely solved. In particular, the volume of reservoir 7 was reduced by 35-50%, depending on the season.

Reservoir 7 is a small reservoir relative to the system size, see Table 2. Hence, the effects of changing the reservoir level will be limited. In fact, the water values may be overruled by other larger reservoirs. E.g. if the water values in the reservoir directly downstream are slightly too high, it may lead to the observed behavior. Therefore, long-term water values is not always the best way to handle small reservoirs. In reality, they may be used as buffer reservoirs and regulated rapidly throughout the day. If this is the case, a solution is to operate with an optimal target reservoir level at the end of the planning horizon instead of the water values.

The purpose of the penalty functions was to illustrate how the reservoirs can be handled with this concept. A set of linear functions describe a relation between cost inflicted to the objective function and the volume of the reservoir in question. This is illustrated in Figure 9. The cost applied to the objective was set to be equal or greater than all of these functions at any given reservoir level, resulting in the cost-volume relation marked in bold black. The mathematical description of the penalty functions can be found in Appendix B.

The input to the model is a set of volume points and the slope of the cost between each of these. Since the purpose was to test the functionality, the input was gradually adjusted towards the final values, which is listed in Table 1. These are also the values that are used in Figure 9.

Table 1: Input data for the penalty functions for reservoir 7. Target reservoir level is 90%.

Reservoir level, Q_{rp}^{Break} [%]	10	40	60	80	90	-
Slope, C_{rp} [EUR/km^3]	5	4	3	2	1	0

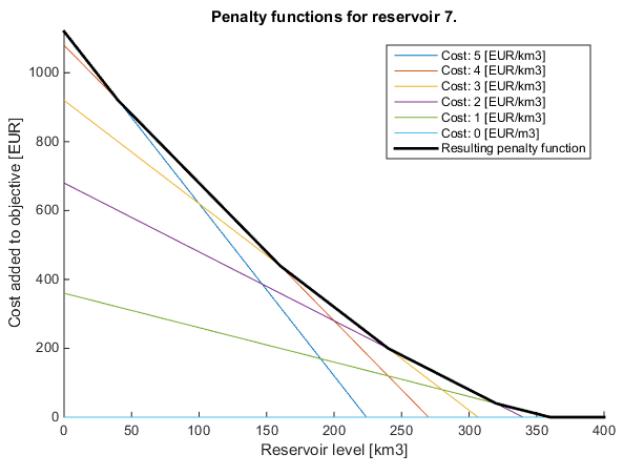

Figure 9: An illustration of a set of penalty functions for reservoir 7.

4.3 Handling Risk

The initial results showed that the expected outcome was increased by including the BM. However, this was to a certain degree at the expense of taking the risk of ending up in scenarios with significantly less income than before. An initial solution to reduce risk was implemented, using a safety-first strategy. According to [20], this strategy aims to "minimize the expected cost while keeping the cost of all the scenarios below a safety level or maximum allowed cost". With the objective formulation used in this model, this translates into maximizing expected revenue while keeping the revenue of all the scenarios above a chosen safety level.

To incorporate the safety-first strategy into the model, the objective value from each scenario when running with the DA market only, Obj_s^{DA}, is used as input data. The value of each scenario objective, obj_s, in consecutive simulations is then forced to be greater than these, minus a tolerance factor, λ. The previous mentioned safety level becomes $Obj_s^{DA} - \lambda$. The tolerance factor can then be adjusted to examine how different factors influence the objective. The is mathematically expressed in Equation 9.

$$obj_s \geq Obj_s^{DA} - \lambda, \quad s \in \mathcal{S} \tag{9}$$

4.4 Issue with Integrality Tolerance

To solve the problem formulated by the model, AMPL utilizes a branching technique to limit the search for optimal solutions. Some integer variables from an initial continuous relaxation are fixed to integers while the other values are adjusted towards the optimum. In this model, it is the generator state variables, γ_{gts}, that can be used for branching, see Appendix A. In some cases, the branching does not limit the search sufficiently to find an optimal solution; there are too many branches with solutions very close to the optimum. This proved to be a problem when running the data set for week 1.

To work around this problem, the integrality tolerance in the CPLEX solver was lowered. This tolerance decides whether or not a variable is a candidate to be fixed to an integer value and used for branching. Valid candidates cannot be further away from an integer value than the tolerance. The default tolerance is $10 * 10^{-5}$. After running the model with the default, an error message suggested to reduce the value to $8 * 10^{-8}$. Setting this value solved the problem and the model finished without errors.

5 Case Study

5.1 The Tokke-Vinje Hydro Power System

The hydro power system that has been examined is the Tokke-Vinje system in Telemark, Norway. The system is located in the NO2 price region of Nord Pool Spot and consists of 11 reservoirs and 8 power plants. An overview of the reservoirs and power plants is listed in Table 2, while Figure 10 shows the interconnections between them. In the latter, the given reservoir numbers will be used as references to their respective reservoirs. Notice that some reservoirs do not have any generator connected. The flow from these reservoirs can still be regulated through what will be referred to as a gate. The gates control the water flow in the river system, and were modeled as a generator with zero production capacity.

Table 2: An overview of reservoirs and generators in the Tokke-Vinje system. The hydro power units are the units immediately downstream of the reservoirs. The production capacity is given as number of generators times capacity per generator.

Reservoir Name	Reservoir Number	Size [Mm^3]	Hydro Power Generators	Production Capacity [MW]
Førsvatn	1	122.0	Kjela	60
Vennemo	2	23.0	-	-
Songa	3	638.6	Songa	120
Totak	4	258.0	-	-
Våmårsvatn	5	26.2	Vinje	3 x 110
Langeidvatn	6	31.8	-	-
Vatjern	7	0.4	Haukeli	2 x 2.2
Vinjevatn	8	11.2	Tokke	4 x 100
Botnedalsvatn	9	58.2	Byrte	20
Byrtevatn	10	75.5	Lio	40
Bandak	11	86.9	Hogga	16

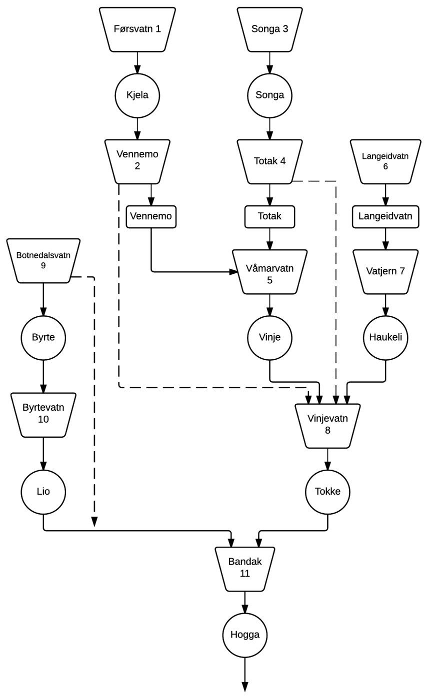

Figure 10: A flow chart showing all reservoirs and hydropower stations in the Tokke-Vinje hydropower system. Arrows indicate flow direction. The trapezoids are reservoirs, circles are hydro power plants and squares are gates. The dotted lines represent the water way for bypass and spillage that does not follow the same path as the discharge.

5.2 Model Input

The model was run for four different weeks: 1, 14, 27 and 44. For each week, the model was run once with the BM deactivated, so that only DA trading is allowed, referred to as DA Only. In addition, the model was run three times with different input prices in the BM. These cases are referred to as Normal BM, Vol1 and Vol2, and are further explained in Section 5.2.1. The data used was gathered from different data sets supplied by SINTEF Energy Research and modified to fit the model format. This includes a data set describing the system in Short term Hydro power Optimization Program (SHOP) [21] and an Excel sheet that summarize the inflow to the reservoir, start up cost and generator capacities, accompanied by detailed inflow data in text-files. Prices were gathered from the Nord Pool Spot FTP-server [22]. The different modifications are explained in the following sections.

5.2.1 Price Input

The price input to the model is based on historical prices that are gathered from the Nord Pool Spot FTP-server. The balancing market has only been in operation since 2010. Therefore, data from 2010 to 2014 was used to generate DA and BM price scenarios. The DA prices that were used are unmodified historical prices. The market prices were analyzed further to find statistical trends that connect the DA and BM prices. Based on these findings, balancing price scenarios were generated. Furthermore, future price scenarios that reflect the expected increase in intermittent energy was developed.

An overview of the simulated market scenarios is presented below in Table 3. The price scenarios will be further described in the following sections. The calculations of the generated price scenarios can be found in Appendix C in the files ScenariosNordic.xlsx and ScenarioGermany.xlsx.

Table 3: Simulated market scenarios

Market case	Description
DA only	No trade in the BM
Normal BM	Trade in the BM activated, BM prices based on historical data from NO2 without modifications
Vol1	Probability of BM prices adjusted
Vol2	Price difference and probability of BM prices adjusted
RKOMX	BM prices as in the Normal case, RKOM activated with X MW/h reserved capacity

5.2.1.1 Scenario Generation of DA Prices

In order to have price input with high validity in the optimization model, price scenarios were generated based on historical price observations. Four time periods were chosen:

- week 1 to simulate the depletion season
- week 14 at the end of the depletion season when the reservoirs are close to empty, but still depleting.
- week 27 when the reservoirs are still filling up.
- week 44 when the reservoirs are full, shortly after the depletion season has started.

Weekends typically have different load profiles than weekdays. In order to avoid using weekend days, the first day of the relevant weeks were used. The DA prices for the relevant day in year 2010 to 2014 were utilized to create the first stage in a scenario, see Section 3.3. Hence, the DA prices were divided into five groups to see the effect that different BM prices have, given the same spot price.

5.2.1.2 Scenario Generation of BM Prices

The balancing prices were generated by analyzing the historical prices. The seasons were divided into three periods based on the seasons' characteristics: spring (week 1-17), filling season (week 18- 39) and the fall (week 40-52).

The historical up- and down-regulation patterns were analyzed to be able to develop realistic price scenarios. The price difference between the DA and BM price was calculated for every hour within the respective weeks in the years 2010-2014. The price differences were then divided into intervals of 1 EUR and the number of occurrences in each interval was counted. Figure 11 illustrates this statistics for week 1-17. Identical analysis is performed for the other seasons, which can be found in Appendix C in PriceStatistics.xlsx.

The up-and down-regulation patterns were then used to create seven price difference intervals that were used as BM price scenarios. The weighted average sum in each interval with corresponding probability of ending up in the interval was calculated. The result is presented in Table 4. The displayed probabilities are for a given DA scenario. As there are five DA scenarios, these must be divided by five in order to find the overall probability of each BM scenario.

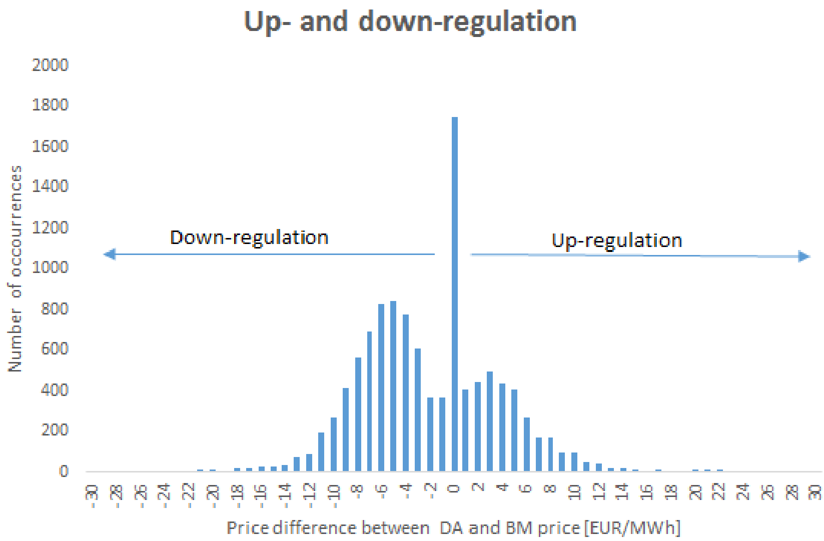

Figure 11: Number of events with up- and down-regulation, week 1-17.

Table 4: Range of price differences between DA and BM with corresponding probabilities, Normal BM, week 1.

BM scenario	Price difference [EUR/MWh]	Probability [%]
1	-75.17	0.26
2	-19.74	2.84
3	-5.69	52.46
4	0.00	15.30
5	4.40	26.84
6	22.31	1.55
7	111.07	0.75

The intervals in the table above were used to create seven balancing price scenarios connected to each of the five DA nodes. One branch in the scenario tree is illustrated below. The DA price with corresponding BM outcomes represents seven scenarios. The altogether five branches create 35 scenarios that were implemented in the optimization model.

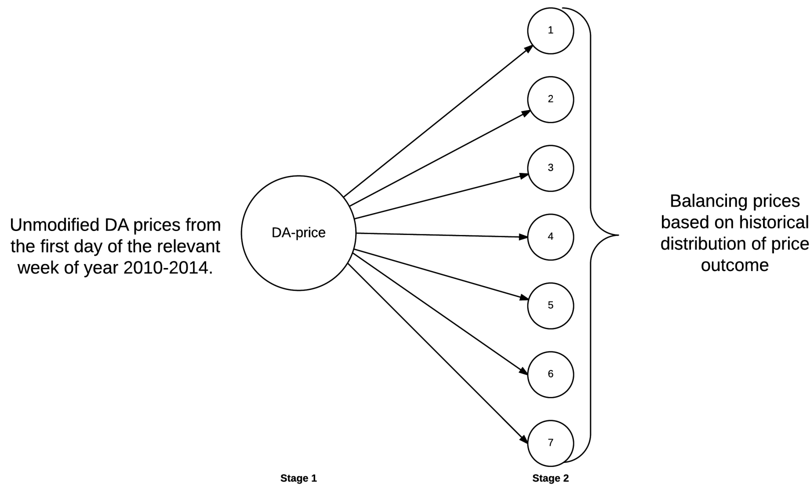

Figure 12: The lower part of the scenario tree. The full tree consists of five DA price nodes, each with seven balancing price nodes connected.

Further analysis was conducted in order to examine if it is possible to predict the outcome of the BM when the DA price is known. The number of up- and down-regulation occurrences as function of average daily DA prices are shown in the scatter plots in Figure 13 and 14. These figures were generated using the Matlab script in Appendix G. Figures for the other time periods can be found in Appendix H. As the figures demonstrate, there are no clear patterns of when up- and down-regulation occurs. Both the number of up- and down-regulations seem to be distributed roughly the same way across the DA prices. The only clear difference is that there are more down- than up-regulations at all price levels. Thus, the DA-price does not give information about the outcome of the regulation direction in the BM. This implies that the market is efficient.

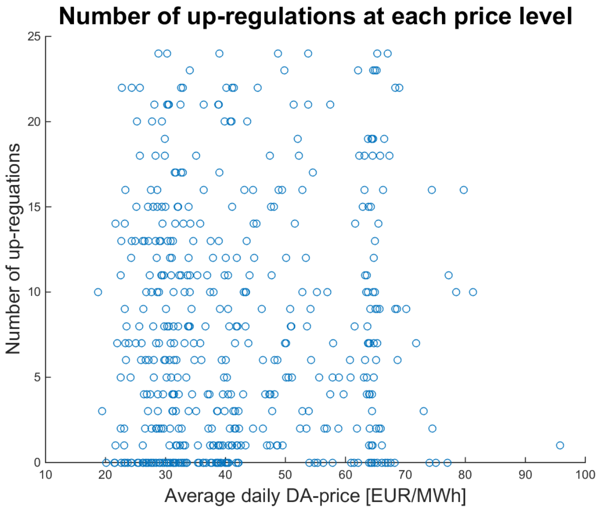

Figure 13: Number of up-regulations each day as function of average DA price the respective day, week 1-17.

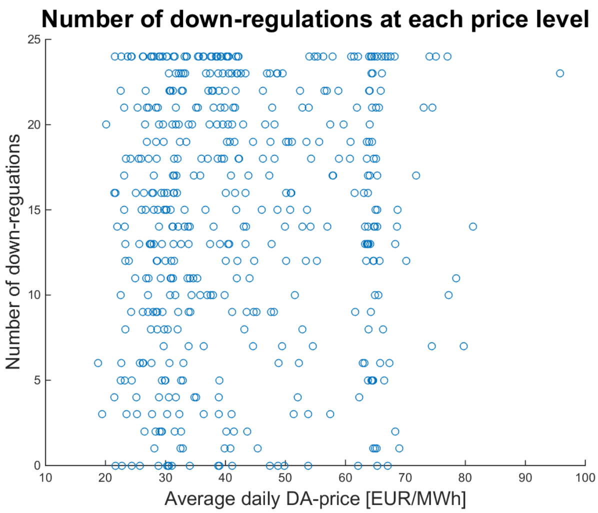

Figure 14: Number of down-regulations each day as function of average DA price the respective day, week 1-17.

5.2.1.3 Price Scenario Generation of Future BM Prices

Based on the reasoning in Section 2.5.1, it is expected a higher price volatility in the future as a consequence of increased intermittent generation. To simulate this, the model was run two additional times for each time period. The price difference intervals from the Normal BM situation were modified in two stages, referred to as Vol1 and Vol2. This is shown in Table 5. The values in the table are based on the following:

Price Volatility 1 (Vol1)
The price differences are identical as in the Normal BM case, while the probabilities were changed. The probability of no regulation, i.e. scenario 4, was halved as it is more likely that regulation is needed. The reduction in probability of scenario 4 was distributed across scenarios 2, 3, 5 and 6 so that the probability of these scenarios were increased with an equal amount relative to the probability of the respective scenarios. The probability of the extreme scenarios 1 and 7 were kept constant. This is because these scenarios likely are due to rare events such as outages and will likely not become more frequent.

Price Volatility 2 (Vol2)
The probability distribution is the same as for Vol1, but with higher price differences in scenario 3 and 5. The price difference in these scenarios was doubled. This is to simulate an increased demand for regulation in the scenarios with high probability.

Table 5: Range of price differences between DA and BM with corresponding probabilities, week 1.

	Vol1		**Vol2**	
BM scenario	Price difference [EUR/MWh]	Probability [%]	Price difference [EUR/MWh]	Probability [%]
1	-75.17	0.26	-75.17	0.26
2	-19.74	3.10	-19.74	3.10
3	-5.69	57.26	-11.39	57.26
4	0.00	7.65	0.00	7.65
5	4.40	29.29	8.81	29.29
6	22.31	1.69	22.31	1.69
7	111.07	0.75	111.07	0.75

5.2.1.4 Price Scenario Generation of Future DA Prices

To simulate another scenario of the future power market, the model was run with historical German DA prices. There are two reasons to do so:

- The German system has a larger share of renewable energy generation and therefore represent a possible future Nordic system with an increased share of renewables.
- It is expected that the Nordic system will become more closely connected to Germany in the future, as explained in Section 2.2.2.

The spot price volatility in Germany is higher than the situation based on the Nordic spot market, mostly because the German generation mix is based on thermal power and contains a high share of intermittent energy. The German market prices were supplied by SINTEF Energy Research and originate from the EPEX Spot FTP-server [23]. The prices were scaled so that the average price across all the DA scenarios became equal to that in the Nordic price case. This was to create consistency with the water values.

Week 1 was chosen as time period to simulate the model with historical German market prices. The price scenarios were divided into three different situations identically as in the section above: Normal BM, Vol1 and Vol2. Again, this was to simulate different levels of intermittent generation.

5.2.2 PQ-Curves

For each power generator, the SHOP data set provides a table of generator efficiency at different values of mechanical input power and one to three tables of turbine efficiencies at different discharges. Each turbine efficiency table is valid at a given head.

The mentioned tables were copied into Excel. The calculations needed to convert the values to PQ-curves were done using basic Excel functions and the Matlab script in Appendix E. First, the shaft power P_{shaft} was found for each discharge in the turbine efficiency tables, using Equation 10.

$$P_{shaft} = \rho g h q E_{turb}(q) \tag{10}$$

ρ is the density of water, g is the gravity acceleration, h is the head, q is discharge through the generator and $E(q)$ the turbine efficiency.

The shaft power found does not necessarily fit the values listed in the generator table. Because of this, the Matlab script was used to interpolate linearly in the generator table to find the efficiencies corresponding to the values from the turbine table.

Having found the correct generator efficiency, $E_{gen}(q)$, for each discharge, the output power was found by multiplying the generator efficiency with the shaft power. The output power with corresponding discharge level gives the break points of the PQ-curve.

This curve may however not be concave. To check this, the properties of a concave function were analysed. The derivative of the function has to be non-negative, i.e. the slope can never increase. This leads to the conclusion that if the curve starts in the origin and one draws a line from the origin to any other point on the PQ-curve, every point previous has to lie at or above this line. This means that the first break point of a concave function has to be the point with the highest X/Y ratio. This corresponds to the point with the maximal total efficiency $(E_{turb}(q) * E_{gen}(q))$.

Different strategies could have been chosen too make sure that the concave PQ-curve deviates as little as possible from the real one. Since most generators typically will be operated close to their maximum efficiency, the accuracy around this point was prioritized. The first break point was therefore copied directly from the efficiency table. If possible, this was also the case for consecutive breakpoints. In the cases where the slope increased from one line segment to the next, the previous line segment was simply extended. As a graphical example, Figure 15 show the original and adjusted PQ-curves for Vinje 2.

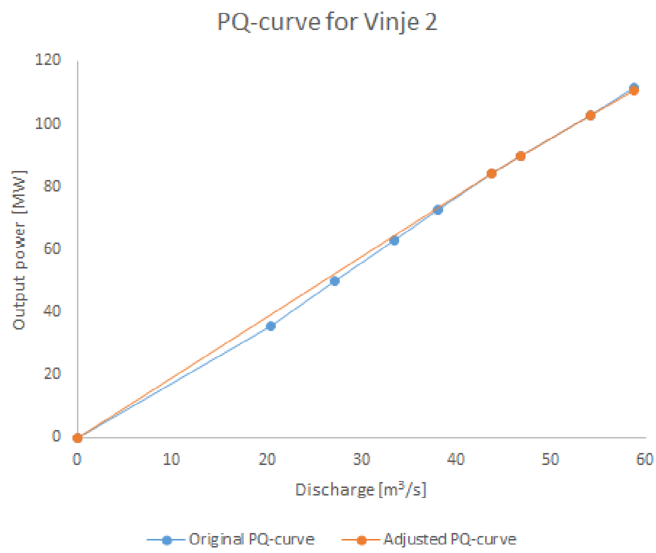

Figure 15: Original and adjusted PQ-curve of Vinje 2.

5.2.3 Inflow

The inflow does not affect the short-term scheduling notably, as described in Section 2.5.2. For this reason, the inflow was set equal for all scenarios. Detailed data for inflow through the year was not available for each reservoir, instead yearly average inflow data provided from SINTEF Energy Research was used. In the Tokke-Vinje system, all inflow is regulated. The yearly inflow was spread across the year using data from nearby measuring stations, which has daily or weekly resolution of the average inflow. The yearly inflow to the reservoir was divided across the year, corresponding to the inflow distribution from the measuring stations. This was done by using Equation 11, where Q^R_{rt} is the hourly regulated inflow used as model input and $Q^R_{r,year}$ is the yearly inflow. Q^R_{mt} is the hourly inflow to the nearest measuring station and $Q^R_{m,year}$ is the yearly inflow to the same measuring station. Q^R_{mt} was calculated by dividing the daily or weekly inflow which was provided by the number of hours per day or week respectively.

$$Q^R_{rt} = Q^R_{r,year} * \frac{Q^R_{mt}}{Q^R_{m,year}} \tag{11}$$

5.2.4 Water Values and Initial Reservoir Level

The marginal water value cuts were calculated in ProdRisk [16] in order to create consistency between short- and long-term optimization. Further explanations about the concept of seasonal scheduling and water value cuts are found in Section 2.4.2 and 2.4.4. ProdRisk is a stochastic dual dynamic programming model developed by SINTEF that creates consistency between inflow- and price scenarios that are generated in EMPS. Several water value cuts are calculated around a reference price and reservoir levels. Hence, it was necessary to find a way to specify these reference levels, which is explained below. This is followed by information about how ProdRisk was run.

The reference price level for each time period was found by calculating the average day-ahead price during all of the DA scenarios for each time period. These prices are historical prices found on Nord Pool Spot's FTP-server. The results of this calculation can be found in Appendix C.

The average reservoir levels for the time periods in question were not available for all the magazines. However, the revision document [24] presents filling profiles in the Tokke-Vinje area. Reference values were chosen based on this material for the relevant weeks, see Table 6. The exception is Vinjevatn which is kept at 50% at all times according to the revision document. The initial reservoir levels in the AMPL model were set equal to the reference values in ProdRisk, enabling the calculation of the marginal water values in the river system.

Table 6: Reference values for water value calculations.

Week	Reservoir level	Average DA price $[\frac{\text{EUR}}{\text{MWh}}]$
1	75%	44.17
14	35%	42.49
27	90%	33.22
44	85%	34.94

To calculate the expected future value of the water, ProdRisk uses price input in csv-format. Prices are divided into four price sections, which represents night, off peak daytime, peak daytime and weekend. Each price interval is valid for one week and there are 156 weeks in one year; thus one year in ProdRisk spans three real years. The predefined settings in the version of ProdRisk was to use data from the fifty years 1931 to 1980. Because the access to these settings was limited, the market data from [19] was modified to fit this format using the Matlab script in Appendix F. Since only data for 1996-2014 was available, the data was copied until all years were filled. The result is that ProdRisk year 1931 contains year 1996-1998, ProdRisk year 1932 contains 1997-1999 and so on until all real years were used. Then the real years were started over to fill the rest of the ProdRisk years.

5.2.5 Bid Curves

The model can be run without using bid curves. In this case, the optimal solution for each day-ahead scenario will be independent of the solution in the other scenarios. The deciding factor for the optimal DA volume is whether or not the expected BM price will be higher or lower than the DA price. This means that one could end up in a situation where it is more beneficial to sell in the DA if the price is low than if it is high. Since Nord Pool Spot requires offered volumes to be non-decreasing with price, this is not possible.

To comply with the rules of Nord Pool Spot, bid curves were introduced. The bid curves are made up of 64 price points, which is the maximum allowed number of bids per order according to [9]. The price points are distributed uniformly between a point slightly below the lowest and one above the highest input DA price. The model then decides upon the volumes that should be offered at each price point. This is implemented in Equations C.26 to C.33.

Bid curves are not necessary in the BM, as the optimal volume will depend on the BM price only because it is the last node of the scenario tree.

5.2.6 Initial and Default Values

All initial flows and generator spinning states were set equal to those that were used in the data set provided by SINTEF and are equal in all simulations. This is not necessarily accurate compared to a normal situation. Since the start up costs are low, it should however not affect the outcome notably. Data for time lag between reservoirs were also left unchanged from the SINTEF data set.

It is difficult to estimate a value for the cost of damage imposed by large amounts on spillage. However, with the implementation explained in Section 4.2.1 and a spillage cost limit of 20 m^3, there were no spillage with the exception of a 0.03 to 0.04 $\frac{m^3}{s}$ spillage from reservoir 8 in hour 24 in week 27. One can therefore conclude that the spillage cost does not affect the optimal solution noteworthy. A value of 1000 EUR/$\frac{m^3}{s}$ from the SINTEF data set was therefore left unchanged.

6 Results

This section introduces the main results from the simulations. The expected income with and without the BM is simulated with prices based on historical Nordic market prices. Price volatility is then introduced to see how it affects the profitability. The same procedure is repeated when the market prices are based on historical German market prices. A closer description of the market cases simulated are found in Table 3. The results have been handled in the Excel sheet results.xlsx that accompanies this report, which is explained in Appendix C. All the results will be analyzed in Section 7.

6.1 Objective Function

Table 7 shows the objective output and distribution between each contributing factor when the BM is disabled. The same values are displayed in Table 8 with the Normal BM prices included, see Section 5.2.1. This table also shows the net gain in objective value from including the BM. These results will be analysed in Section 7.1.1.

As Table 7 and 8 illustrate, the start up- and spillage costs are insignificant compared with the other contributing factors; therefore, they will not be displayed in the rest of the results. The values can be found in results.xlsx.

Table 7: Value of objective and contributing factors with BM disabled $[\frac{\text{kEUR}}{\text{day}}]$.

	Week 1	Week 14	Week 27	Week 44
Spillage cost	0.00	0.00	0.00	0.00
Start up cost	0.70	0.70	1.10	0.40
Day-ahead income	900.76	838.08	669.38	728.73
Increased water value	-504.13	-491.49	526.44	-343.40
Objective	395.13	344.79	1193.72	383.72

Table 8: Value of objective and contributing factors with BM included. Price input according to the normal case [$\frac{\text{kEUR}}{\text{day}}$].

	Week 1	Week 14	Week 27	Week 44
Spillage cost	0.00	0.00	0.00	0.00
Start up cost	1.16	0.53	1.46	1.02
Day-ahead income	1001.99	935.78	695.43	728.73
Balancing market income	-102.70	-72.47	-18.84	6.88
Increased water value	-481.35	-496.54	526.98	-340.52
Objective	415.85	365.01	1201.46	392.72
Gain from including BM	20.72	20.22	7.74	9.00
as % of original income	5.24%	5.86%	0.65%	2.35%

6.1.1 Introduction of Price Volatility

Different levels of price volatility between DA and BM are introduced in order to represent the future with a high intermittent energy penetration. The different cases with increasing level of price volatility are referred to as Normal BM, Vol1 and Vol2, respectively. See Section 5.2.1.1 for explanation.

Figure 16 shows the total change in objective value, while Figure 17, 18 and 19 show the income from the DA and BM and the increased water value, respectively. These will be discussed in Section 7.1.2.

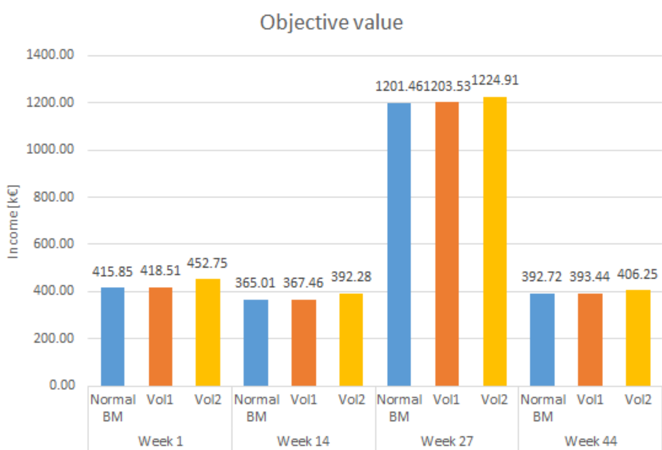

Figure 16: Objective value for all time periods [$\frac{\text{kEUR}}{\text{day}}$].

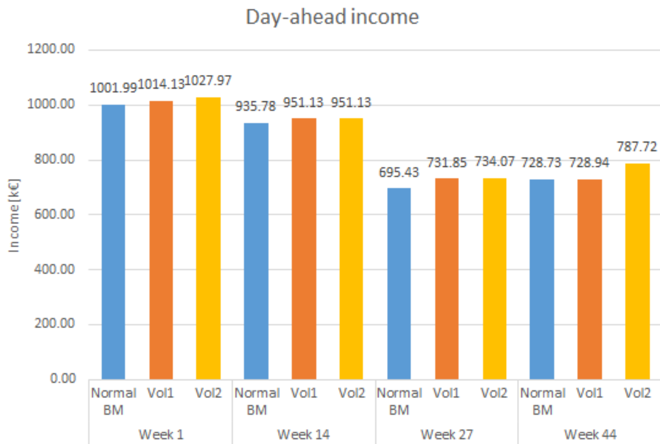

Figure 17: Income from day-ahead market for all time periods $[\frac{\text{kEUR}}{\text{day}}]$.

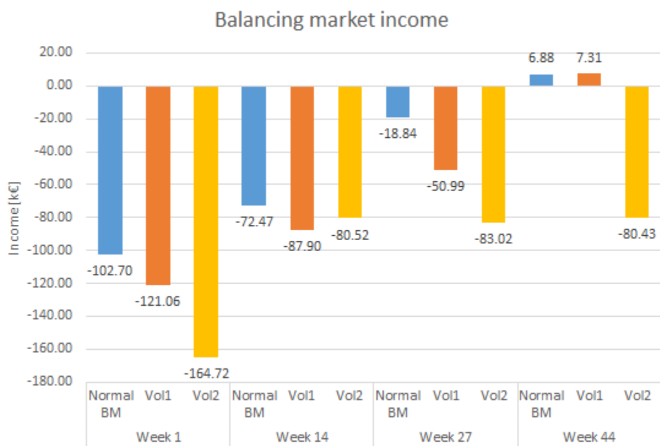

Figure 18: Income from balancing market for all time periods $[\frac{\text{kEUR}}{\text{day}}]$.

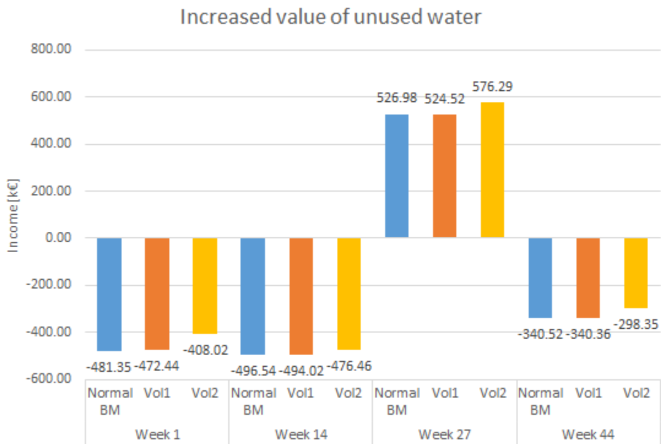

Figure 19: Increased value of total unused water in all reservoirs $[\frac{\text{kEUR}}{\text{day}}]$.

6.2 Introducing German Market Prices

The same procedure covering DA, Normal BM, Vol1 and Vol2 is conducted with DA price scenarios based on historical German prices. Section 5.2.1.4 provides information about the price scenario generation. The objective value and its contributing factors are examined and compared with the Nordic price cases from the section above.

Figure 20 summarizes the objective values with varying price volatility. Table 9 specifies the changes in income when the price scenarios are based on German prices instead of Nordic prices. Figure 21 displays how the contributing factors are affected by the German prices. The information is based on simulations of week 1. The result will be discussed in Section 7.1.4.

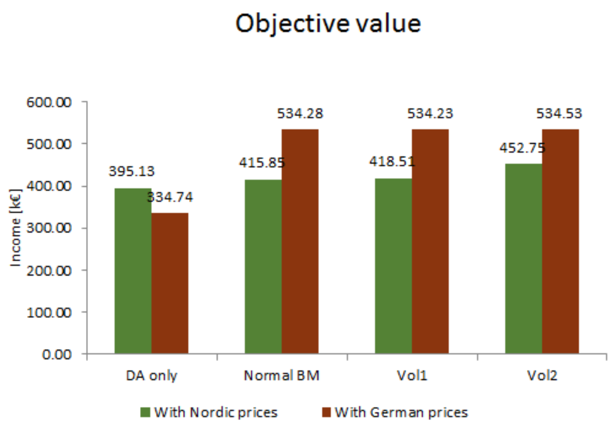

Figure 20: Expected profit with price scenarios based on Nordic and German market prices $[\frac{\text{kEUR}}{\text{day}}]$, week 1.

Table 9: Increase in objective value with different market cases compared to DA only, week 1.

Increase in objective value

	Normal BM	Vol1	Vol2
[kEUR]	199.54	199.49	199.79
[%]	59.61 %	59.60 %	59.69%

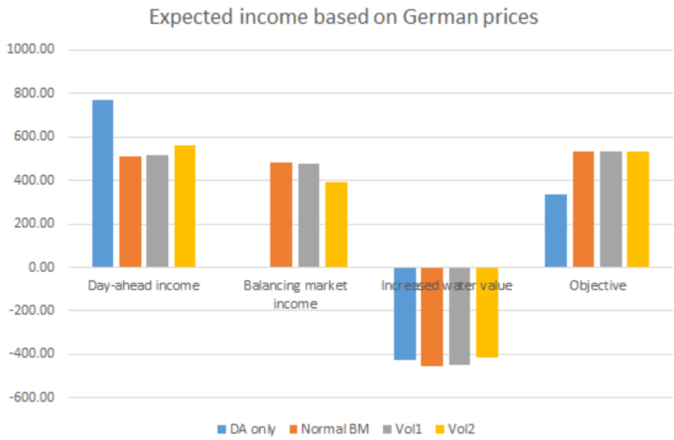

Figure 21: Expected income for different factors based on German market prices, week 1 $[\frac{\text{kEUR}}{\text{day}}]$.

6.3 Including the RKOM

To examine how the RKOM can be utilized, the model is run with three different reserved capacities. An explanation of the implementation can be found in Section 4.1. Table 10 and 11 show the results from the simulations for week 1 and 44, respectively. These results will be analysed in Section 7.2.1 and 7.2.3.

Table 10: Change in results when introducing the RKOM compared to the Normal BM case for week 1.

Capacity reserved in RKOM [MW/h]	**20**	**50**	**80**
Day-ahead income [kEUR]	-19.54	-41.55	-69.37
Balancing market income [kEUR]	8.66	21.18	36.52
Increased water value [kEUR]	8.19	13.56	21.90
Objective [kEUR]	-2.68	-6.78	-10.91

Table 11: Change in results when introducing the RKOM compared to the Normal BM case for week 44.

Capacity reserved in RKOM [MW/h]	**20**	**50**	**80**
Day-ahead income [kEUR]	-9.94	-34.04	-48.25
Balancing market income [kEUR]	6.10	21.50	28.55
Increased water value [kEUR]	3.23	10.60	16.12
Objective [kEUR]	-0.60	-2.13	-3.84

There were similarities between how the RKOM and the risk implementation affected the results. Therefore, it was necessary to look at the volumes traded in the different markets for these cases. Figure 22 shows the volumes traded in week 1 for the relevant scenarios. These will be compared with the results from the risk simulations in Section 7.2.3.

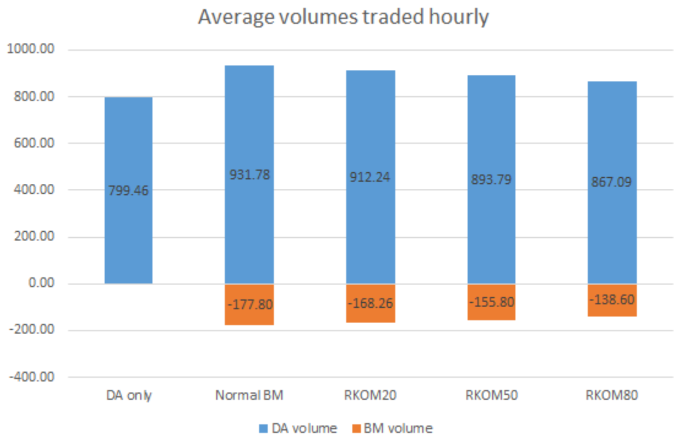

Figure 22: Average volumes traded hourly in week 1 [MWh].

6.4 Handling Risk

The method for handling risk is intended to illustrate a concept; therefore, the risk handling is tested for week 14 only. In this week, several scenarios had lower revenues with the BM included than with DA only and was therefore suitable. The implementation of the risk handling method is explained in Section 4.3.

The model is run with four different tolerance factors, λ: 1, 5, 10 and 15 kEUR. An overview of the results are displayed in Figure 23, while Table 12 shows the absolute and percentile reduction in objective value. Table 13 shows the DA income in the second column followed by the difference compared to it at different values of λ. This will be analysed in Section 7.2.2.

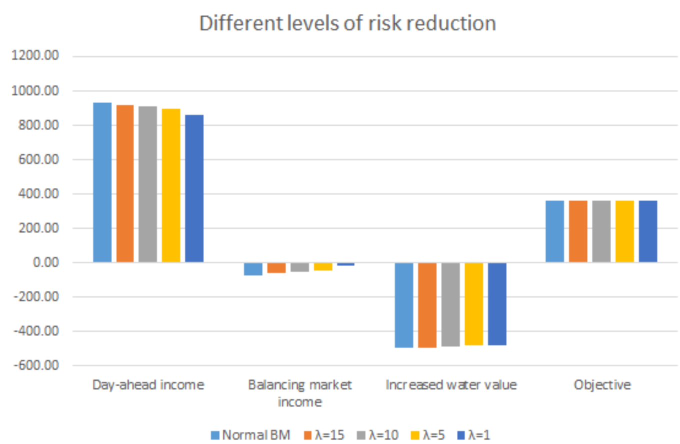

Figure 23: Income at different safety levels, week 14.

Table 12: Increase in objective value for different safety levels. Value of λ in [kEUR].

	Increase in objective			
	$\lambda = 15$	$\lambda = 10$	$\lambda = 5$	$\lambda = 1$
[kEUR]	-0.30	-0.55	-0.86	-2.30
[%]	-0.08 %	-0.15 %	-0.24 %	-0.63 %

Table 13: DA scenario income and change in scenario income at different risk safety levels [kEUR].

	DA income	Difference compared to DA income				
		Normal BM	$\lambda = 15$	$\lambda = 10$	$\lambda = 5$	$\lambda = 1$
s01	409.28	1301.22	1301.22	1301.22	1301.22	1301.22
s02	409.28	65.59	65.59	65.59	65.59	65.59
s03	409.28	0.26	0.25	0.26	0.26	0.26
s04	409.28	0	0	0	0	0
s05	409.28	0	0	0	0	0
s06	409.28	0.05	0.05	0.05	0.05	0.05
s07	409.28	2.12	2.12	2.12	2.12	2.12
s08	808.33	903.7	903.7	903.7	903.7	903.7
s09	808.33	0.51	0.51	0.51	0.51	0.51
s10	808.33	0.09	0.09	0.1	0.1	0.1
s11	808.33	-0.07	-0.07	-0.07	-0.07	-0.07
s12	808.33	-0.07	-0.07	-0.07	-0.07	-0.07
s13	808.33	-0.02	-0.02	-0.02	-0.02	-0.02
s14	808.33	0.24	0.24	0.24	0.24	0.24
s15	**32.14**	**1347.71**	**1194.37**	**1108.47**	**1010.83**	**895.14**
s16	**32.14**	**316.19**	**275.92**	**253.36**	**227.72**	**197.34**
s17	**32.14**	**69.3**	**57.7**	**51.2**	**43.8**	**35.05**
s18	**32.14**	**-24.29**	**-15**	**-10**	**-5**	**-1**
s19	**32.14**	**-24.3**	**-14.83**	**-9.8**	**-4.08**	**2.69**
s20	**32.14**	**32.95**	**78.46**	**103.96**	**132.94**	**167.27**
s21	**32.14**	**425.05**	**651.62**	**778.54**	**922.81**	**1093.75**
s22	443.88	1266.62	1266.62	1266.62	1266.62	1266.62
s23	443.88	44.84	44.24	45.73	45.7	45.56
s24	443.88	0.13	0.12	0.13	0.13	0.13
s25	443.88	0	0	0	0	0
s26	443.88	0	0	0	0	0
s27	443.88	0.09	0.09	0.09	0.09	0.09
s28	443.88	2.15	2.15	2.15	2.15	2.15
s29	**30.32**	**1378.33**	**1310.36**	**1233.86**	**1152.21**	**807.87**
s30	**30.32**	**325.37**	**307.52**	**287.43**	**265.99**	**175.56**
s31	**30.32**	**72.86**	**67.71**	**61.92**	**55.74**	**29.68**
s32	**30.32**	**-19.96**	**-15**	**-10**	**-5**	**-1**
s33	**30.32**	**-19.96**	**-4.37**	**-4.37**	**-4.37**	**15.81**
s34	**30.32**	**39.09**	**106.2**	**106.2**	**106.2**	**208.4**
s35	**30.32**	**397.19**	**731.3**	**731.3**	**731.3**	**1240.1**

As explained in Section 6.3, it was necessary to look at the volumes traded in the DA and BM for different levels of risk reduction. Figure 24 shows the volumes traded in week 14 for the relevant simulations. These will be compared with the results from the RKOM simulations in Section 7.2.3.

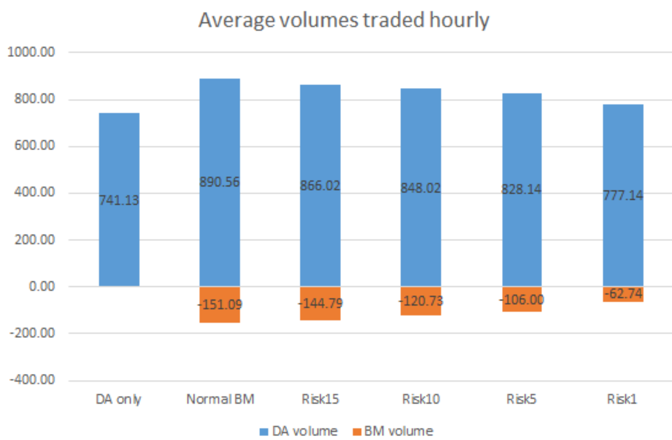

Figure 24: Average volumes traded hourly in week 14 [MWh].

6.5 System Behaviour

With the new waterways and limits on spillage, the behavior of the system was improved. This section provides information about the system behavior in the optimal solution. These results will be discussed in Section 7.2.

6.5.1 Spillage

With the new implementation to inhibit spillage, see Section 4.2.1, there is no spillage from any of the reservoirs in any of the simulations. The exception is week 27, where some spillage occur from reservoir 8 in the last hour of some of the scenarios. The largest spillage is observed during the Volatility-simulations, where the weighted average of this spillage across the scenarios is $0.04m^3$. This is considered a negligible amount and will therefore not be analysed further.

6.5.2 Changes in Reservoir Level

The change in reservoir level from the beginning of the planning horizon to the end is large for some reservoirs. This trend is similar for all weeks. For the purpose of this analysis, the focus will be on week 27. Corresponding results for the other weeks can be found in the accompanying Excel sheet results.xlsx in Appendix C.

As Figure 25 shows, the reservoir level of reservoir 7 was reduced by around 40% of its maximum capacity, while reservoir 8 was increased by around 30%.

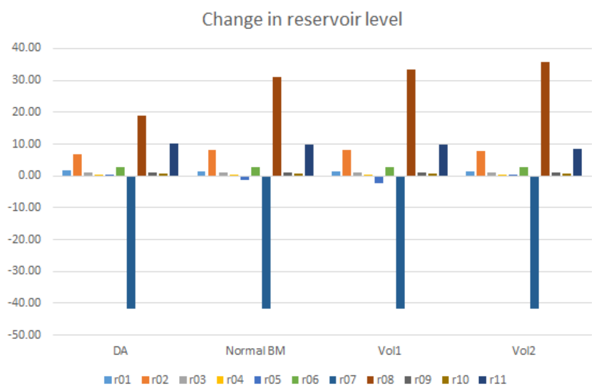

Figure 25: Change in reservoir level week 27.

6.5.3 Introducing Penalty Functions

As explained in Section 4.2.2, penalty functions are introduced in order to force reservoirs to stay closer to a chosen target level. Penalty functions are applied to reservoir 7 only and are the same as those shown in Figure 9.

Figure 26 shows that the volume of reservoir 7 is reduced less than without the penalty functions, from -41.84% to -26.96%. The penalty cost of this change was 180 EUR/day, while the total objective losses amounted to 300 EUR/day, making the net loss 120 EUR/day. This corresponds to a 0.01% decrease in total income.

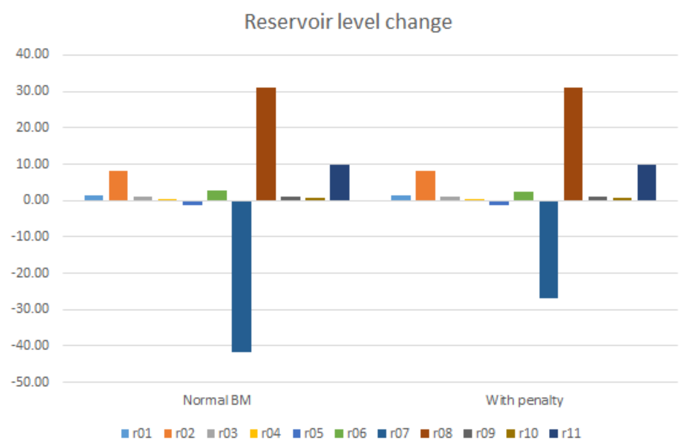

Figure 26: Change in reservoir level week 27 with and without penalty functions.

7 Analysis

This section covers a discussion of the results. The findings from the optimization of the original model will be described in the Section 7.1. Section 7.2 covers a discussion of the results from the simulations where the model is modified.

7.1 Model Characteristics

7.1.1 Optimal Expected Income

Table 7 and 8 compare the expected income when participating in the balancing market in addition to the day-ahead market. As the tables demonstrate, the highest increase in expected income occurs in the depletion season, constituting an additional gain of 20.75 kEUR per day. The benefit of participating in BM is also notable for the other seasons.

This finding is as expected with the following reasoning. Suppose the DA allocation from the simulation without the BM should be kept with no changes. It is clear that allowing trade in the BM afterwards would provide at least the same solution. Most likely the solution will be improved, as some prices in the BM should provide beneficial trade options. In addition, letting the model choose the optimal allocation in the DA based on the expected BM price will provide an equal or better solution. Some scenarios could provide worse results, which will be further discussed in section 7.2.2, but the expected total outcome will always be at least as good when including more trade options.

The results presented in the tables also provide information about how the gains are achieved. When the total income from the DA increases by including BM, the BM income is negative. This is the case in week 1, 14 and 27, as shown in Table 8. This indicates that the gains are achieved by bidding more into the DA and then down-regulate in the BM. The volumes traded in the different markets support this conclusion. Graphs that show the volumes are found in results.xlsx under the tabs named "Compare <week number>".

For week 44, the DA income is unchanged and the BM income is positive. With the above reasoning, this indicates that up-regulation is dominant. However, the volume graphs show that there is slightly more down-regulation. Hence, there is more volume traded as down-regulation, but the prices make the total income larger from up-regulation. This explains the positive BM income in week 44.

The increase in value of the unused water is smaller in week 14 and 27 when including the BM. This indicates that the overall production level is increased. The opposite is the case for week 1 and 44.

7.1.2 Impact of Price Volatility

Figure 16 shows that when the volatility of the balancing prices increase, the overall income increases. This is as expected. The original solution shows that the optimal solution is to use the price difference between the DA and the BM to create increased revenues. When the price difference increases, the revenues are likely to increase or at least stay unchanged.

Furthermore, the profitability in both markets is affected. This is illustrated in Figure 17 and 18. The DA income increases or remains unchanged with price volatility in all the seasons. Since down-regulation was dominant in all the four weeks with normal prices, it is to be expected that the model will down-regulate even more as the volatility increase. Bidding more into the DA opens up for more down-regulation in the BM.

The BM income is most affected by the changes, with the income expected to decrease with the volatility in most of the cases. In week 27, for instance, the balancing income is expected to decrease with 107.1% and 340.7% for Vol1 and Vol2, respectively. The decrease in BM income corresponds well with the above-reasoning that the model aims to down-regulate more as volatility increases.

The Vol2 case in week 14 and 44 deviate from the general pattern. While the absolute value of the income in the BM becomes larger in the dominating direction with increasing volatility, the opposite happens in these cases. This indicates that there is a turning point where the benefits from the opposite direction becomes dominating. In week 14, this means that up-regulation constitutes a larger share of the income than before. A reason for this could be that further down-regulation gives end reservoir levels that result in low water values. Each additional unit of down-regulation will give decreasing benefits as each additional unit in the reservoirs will be decreasingly valuable.

The deviation in week 44 has a similar explanation as above. As explained in Section 7.1.1, the traded volumes show that down-regulation is dominant, even though the income in the BM is positive. The reason that the BM income changes direction in the Vol2 case is likely because the income from up-regulation reaches a maximum. Because the volume traded in the DA is close to the maximum capacity, approximately 912 out of 990 MWh/h, the possibility of up-regulation is limited. The negative income from down-regulation therefore becomes dominant.

7.1.3 Seasonal Variations

Seasonal variations should be reflected by the increase in water value, which is shown in Figure 19. The reason is that the goal of the seasonal planning is to handle the reservoir level to yield optimal income over time. This means that during the filling season, the reservoir levels should generally increase, while in the depletion season they should decrease.

As Figure 19 illustrates, this is also the case. In week 1, 14 and 44, the water value is reduced, which means that the reservoirs are emptying. The opposite is the case for week 27, when the reservoir fills up again. This indicates that the connection to the long term scheduling through the water values works as intended.

7.1.4 Impact of German Market Prices

Section 6.2 presents the main results when German market prices are implemented in the model. The most important findings are illustrated in Figure 20, and the changes in the objective value are specified in Table 9. The revenues are 15.28% lower than in the Nordic price case when the BM is not active. When the BM is included, however, the objective function increases by 59.61% from the original income of 334.74%. The new income is 28.48% higher than the same scenario with the Nordic prices. Thus, the results suggest that value of including the BM is even higher if the prices develop to become more similar to the German prices. This is expected to happen, as explained in Section 5.2.1.4, and underlines the need to include the BM in production planning.

As Figure 20 shows, the income does not increase as much with price volatility with the German prices as with the Nordic. In fact it is slightly reduced in the Vol1 case. This can be explained supported by the illustration in Figure 27. A consequence of the volatile German DA prices is that some DA prices will be very high and other prices very low. This will lead to very high and very low DA volumes, respectively. The results in the Excel sheet results.xlsx under the tab "Compare Ger" verifies that this is the case.

Because the traded DA volumes are close to either the production cap or zero the regulation in one direction will often be limited, as illustrated in Figure 27. The trend in the BM will therefore be to down-regulate when the DA prices are high and up-regulate when the prices are low. If there are approximately an equal amount of hours with high and low DA prices, the overall BM outcome will not change notably. Both the negative BM income when the DA prices are high and the positive BM income when the DA prices are low will increase, but the sum of the BM income changes little.

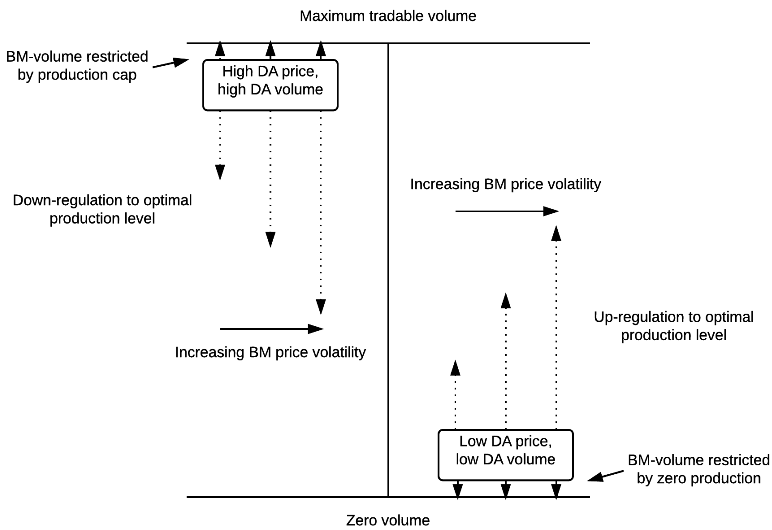

Figure 27: Illustration of how DA price volatility limits BM regulation.

Figure 21 confirms that this could be the case. The DA income is increased slightly with price volatility, which allows more down-regulation than in previous results. The difference compared to the Nordic DA price case is that the DA volumes are already close to the production limit. By bidding more in the DA, the income from up-regulation will be reduced. In comparison, Figure 28 shows a case which is common with the Nordic prices, where a moderate volume is traded in the DA. Even if the DA volume should be increased slightly in order to allow more down-regulation, there is still room for up-regulation if required. The result is that with the German DA prices, the increase in DA income and remaining water value barely covers the decrease in income in the BM.

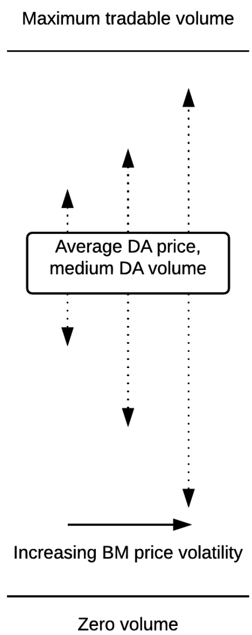

Figure 28: Illustration of normal DA prices and corresponding BM regulation.

7.2 Model Modifications

7.2.1 Including the RKOM

With the RKOM restrictions included in the model, the objective value is reduced by up to -10.91 kEUR per day, as shown in Table 10 and 11. The tables also show that the DA income is reduced, while the BM income is increased with larger RKOM capacity. This is as expected, as the restrictions force the producer to hold back in the DA and sell up-regulation when needed. The up-regulation volume in the BM is also larger or equal to the reserved capacity for all scenarios with higher BM than DA price, see Excel sheet results.xlsx in Appendix C. This indicates that the implementation works as intended. An explanation of the implementation is found in Section 4.1

The goal of this implementation is to estimate a price per MW/h that the producer would need to get payed in order to break even compared to not trading in the RKOM. This is done by using Equation 12.

$$P^{RKOM} = \frac{\Delta Obj * 1000}{X^{RKOM} * 18} \tag{12}$$

ΔObj is the reduction in objective function in kEUR compared to the Normal BM case. X^{RKOM} is the reserved RKOM capacity, measured in MW/h in each of the 18 daytime hours. The resulting price per MW/h, P^{RKOM}, is listed in Table 14.

Table 14: RKOM price required to break even for different reserved RKOM capacities.

	P^{RKOM} [EUR/MW/h]	
RKOM volume [MW/h]	Week 1	Week 44
20	7.44	1.67
50	7.53	2.37
80	7.58	2.67

RKOM is a new market, thus the only existing market data available is from the winter 2014/2015. This data can be found in Appendix D. The data shows that the traded capacity in the RKOM was highest in the weeks 2 through 10. The price peaked in week 6 at 10.6 EUR/MW/h, using an exchange rate of 8.5 NOK/EUR, which was the only price level that would make it beneficial for the producer to participate in week 1. The P^{RKOM} in week 44 is lower, but it would not be beneficial to trade before the price reaches the level of week 3, i.e. 1.765 EUR/MW/h.

The producer takes a risk by participating that is not accounted for in the above calculations because the RKOM is cleared for an entire week at a time. This risk will be weighted against the expected increase in revenues. The results show that the conditions for which the revenues are increased were rare during the winter season 2014/2015. Therefore, the RKOM does not currently seem very attractive for this particular producer. However, this conclusion may change if the RKOM prices rise in the future.

7.2.2 Handling Risk

The ten scenarios that are highlighted in Table 13 are affected when the safety level of risk is introduced. As the table shows, it is scenario 18, 19, 32 and 33 that force the change in the market income as these originally had a lower income than the applied safety level. These are all scenarios with a relatively high probability. Each of scenario 18 and 32 has a 4.33% and scenario 19 and 33 a 6.42% probability of occurring, which makes the total probability of ending up in any of these scenarios 21.50%. The probability of the BM scenarios, given a DA scenario, are displayed in Table 4.

The outcome in all of these scenarios is significantly improved. When $\lambda = 1$, the 21.50% chance of ending up in a scenario with losses around 20000 € is reduced to a 8.7% chance of a loss of 1000 €. This is at the cost of a 2300 € reduction in expected income, as Table 12 points out. This is valuable decision support for a producer.

An interesting observation in Table 13 is the distribution of the risk. As mentioned above, all the scenarios that constitute a risk are relatively probable. The scenarios with very low probability all give positive income changes, most of them give very large incomes. This is also valuable knowledge for the producer as there are no scenarios with very low probability and dramatically worse income than in the DA Only case. This means that if the producer choose to disregard the risk, he will experience low-income days relatively frequently, but no extreme negative days. The producer will have to decide whether or not the frequent low income days are worth the expected increase in income.

The safety-first strategy is rigid, as it does not weigh unfavorable outcomes with respect to probability. Regardless, the results show that it efficiently removes risk connected to unfavorable scenarios. It is however important that one does not confuse this reduction in risk with the risk of inaccurate scenarios. The latter is connected to the likelihood of being wrong when predicting the future and is not examined in this thesis. The implemented risk reduction is based on the assumption that all the scenarios and corresponding probabilities are correct.

7.2.3 Comparing Reduced Risk with RKOM

Figure 23 shows the distribution of the income when the safety level of risk is introduced. The income in the DA and the negative income in the BM are both reduced. Less volume is traded in the DA and the trade in the BM is shifted upwards with less down-regulation and more up-regulation. As down-regulation is the general trend in all weeks, this leads to the conclusion that the risk is reduced when the balancing market is utilized less.

Table 10 and 11 display the same for the RKOM simulations for week 1 and 44, respectively. The tables show a pattern that is very similar the pattern in the risk reduction simulations. It was therefore interesting to compare the volumes in these scenarios.

Figure 22 and 24 confirm the similarities found in the income distribution. Both when the risk level is increased (λ is decreased) and when the RKOM capacity is increased, the volume is shifted from the BM over to the DA. Clearly, the expected outcome is increased by bidding more into the DA and then buy down-regulation in the BM to avoid producing too much. The risk is connected to scenarios where the BM price is higher than the DA price so that the producer will be forced to produce more than otherwise optimal. The cap that the RKOM impose on the DA volume reduces the risk of having to produce too much, which is why the RKOM results are so similar to the results from simulations with reduced risk.

With respect to what was mentioned in Section 7.2.1, there is a risk in making a decision to reserve capacity a week before it is produced. The risk implementation, however, shows that the risk is reduced when less volume is traded in the DA. Hence, the producer must consider following aspects when deciding whether to bid in the RKOM or not; he must weigh the risk involved in allocating capacity a week ahead against the possible increase in income and the reduction in risk caused by the change in bidding strategy.

7.2.4 Including Penalty Functions

Figure 26 shows the change in reservoir levels with and without penalty functions on reservoir 7. The behavior in this reservoir changed as intended as the large negative change in reservoir level is reduced. The change in objective value is small because the reservoir is small compared to the system size, see Section 5.1. This supports the assertion that small reservoirs should not be handled by long term water values as these have very little impact on the objective value.

With the penalty functions included in the model, the water value of reservoir 7 was not excluded from the objective. The model will still weigh the penalty cost of deviating from the target volume against the other benefits, including the value of the unused water. This is acceptable for the purpose of testing the impact of penalty functions. The results are directly comparable with previous results as only an additional cost is added. For real life use, it may however be better to exclude the reservoirs that are being handled by penalty functions from the water value calculations. This is because the reason for including penalty functions was to find a way to handle reservoirs that are regulated on short-term basis. Long term water values are not necessarily suitable to handle such reservoirs.

If one should exclude reservoir 7 from the water value calculations, the penalty cost would still be weighted against the remaining sources of income. It is in this case important that the cost reflects the short term optimal production plan, so that the penalty cost reflects the cost and risk involved in deviating from the target volume.

8 Conclusion

The results of the optimization have shown that a hydro power producer in the case-study area increases the expected income by participating in the balancing market. The results suggest that by utilizing the balancing market, the profit may increase with 5.24%, 5.86%, 0.65% and 2.35%, for week 1, 14, 27 and 44, respectively. This is compared with the original income when bidding into the day-ahead market only. The highest increase in expected income occurred in week 1, i.e. the depletion season. It constituted an additional gain of 20.75 kEUR per day, from an original income of 415.88 kEUR.

The model was also run with German day-ahead prices for week 1. This was to account for a stronger future connection with the German market and because the German power market already has a large share of intermittent generation. With these prices, the gain from including the balancing market was even greater than with the Nordic prices. The increase was 199.54 kEUR per day, which corresponds to a 59.61% increase from the original income of 334.74 kEUR.

To simulate a higher share of intermittent generation, the price volatility in the balancing market was increased. This lead to a further increase in income in both cases, though the effects were greater with the Nordic prices. Regardless, these findings underline the need to include balancing markets in production planning.

While the benefits of including the balancing market in the production planning are clear, it is important to be aware of the added risk of doing so. A safety-first strategy was applied to examine how the risk could be reduced. The result showed that the risk could be reduced from approximately a 21.5% chance of a 20 000 € loss to a 8.7% of a 1 000 € loss by changing the bidding strategy. The cost of this reduction was a decrease of 2300 € in expected income. The losses are reduced income compared to the results from including the day-ahead market only. This information gives the producer valuable decision support.

In addition to the day-ahead and the balancing market, the capacity market, RKOM, was implemented. The results indicate that it is not presently profitable to participate in this market. However, the changes in bidding strategy that were necessary when RKOM was included were similar to the changes that were done to reduce risk. This may make a producer willing to participate even though the expected profits are reduced. Furthermore, it may be attractive to participate in the RKOM in the future if the prices of capacity reservation increase sufficiently.

A consequence of the model being a prototype that is not fully developed is that certain implementations need tuning. Problems related to reservoir behavior and spillage emerged in early simulations. Several improvements were done to solve these, including new restrictions on spillage and the introduction of penalty functions to handle reservoirs. With the penalty functions included in the model, the behavior of the reservoirs changed as intended. The large negative change of reservoir level that was observed in reservoir 7 got reduced. The final results also showed that the spillage restrictions worked as intended.

9 Future Work

There are aspects of the optimization model than can be further investigated to improve the validity and application of the results. The most notable improvement potential is the price scenario generation, as this model input has a great impact on the result. In reality, a hydro power producer spends a large amount of resources when generating price forecasts because it is critical to have accurate forecasts when planning future power production. These forecasts are often confidential and were therefore not possible to acquire. Running the model with comprehensive future price forecasts would be valuable to validate the findings in this thesis.

With the German market prices introduced to the model, the reference price in ProdRisk was found by scaling the German average day-ahead prices to equal the Nordic price levels. This means that the water value cuts calculated in ProdRisk are based on Nordic prices. Although it is not expected to have a major impact on the result, an improvement is to change the price input in ProdRisk for the German market case. This will generate more accurate water value cuts.

The RKOM-H results showed that the capacity market is not presently very attractive, but this may change in the future. Hence, it is relevant to extend the RKOM implementation to include RKOM-B. Furthermore, Nord Pool Spot is regularly implementing new functionality in all markets that should be implemented in the model.

To achieve a complete model of all the existing markets, one could also consider to incorporate the intra-day market. This is however not recommended to prioritize because of the following reason. When the model is run, the producer gets information on how to act on the balancing market prices. The intra-day market is a continuous market that gives similar trading opportunities as the balancing market. Therefore, the producer already has the information needed to make decisions when considering offers in the intra-day market. The producer only has to consider these offers compared to the chance of getting even better prices in the balancing market. Therefore, implementing the intra-day market does not necessarily provide additional decision support.

The results of the simulations suggest that it is profitable to participate in the balancing market, which means the generator production may change frequently. The model provides information about the production pattern of each generator, however detailed study of this is not performed in this thesis. It is important to evaluate the consequences the production behavior may have on the machinery, reservoir and rivers. Challenges related to e.g. sediments, maintenance and river flows might arise. These should be examined in order to obtain a complete overview of the impacts from the changes in production planning.

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A Mathematical Model Description

All the determinants are defined systematically in the model by using different types depending on what it represents (endre formulering). The sets are written in $\mathcal{CAPITAL\ CALLIGRAPHIC}$ letters and parameters in capital Latin or Greek.

Indexes and decision variables are written in lower case Latin, except binary variables, which are written in lower case Greek letters. Subscript is used for indexes, while superscript is used to describe the type of variable or parameter. The superscript on sets indicated that they are subsets or a part of a larger set. Parameters marked with an over- or underline are upper and lower limits, respectively.

Set

$\mathcal{S}$	Scenarios
$\mathcal{M}$	Scenario tree stages
$\mathcal{N}$	Scenario tree nodes
$\mathcal{N}_m$	Nodes within stage m in $\mathcal{M}$
$\mathcal{S}_n$	Scenarios going through node n in $\mathcal{N}$
$\mathcal{T}$	Operational time periods
$\mathcal{T}^M$	Market periods
$\mathcal{T}^A = \mathcal{T} \cup \mathcal{T}^M$	All periods
$\mathcal{R}$	Reservoirs
$\mathcal{R}_r^D$, $\mathcal{R}_r^S$, $\mathcal{R}_r^B$	Reservoirs who's discharge, spillage and bypass flow into r
$\mathcal{T}_{\hat{r}t}^D$, $\mathcal{T}_{\hat{r}t}^S$, $\mathcal{T}_{\hat{r}t}^B$	Time periods when water is discharged, spilled or bypassed from reservoir $\hat{r}$ to arrive downstream at t
$\mathcal{J}$	Water value cuts
$\mathcal{G}_r$	Generators connected to reservoir r in $\mathcal{R}$
$\mathcal{G}$	All generator sets combined ($\mathcal{G} = \cup_{r \in \mathcal{R}} \mathcal{G}_r$)
$\mathcal{I}$	Line segments on the PQ-curve
$\mathcal{K}$	Thermal generators
$\mathcal{B}_{DA}$, $\mathcal{B}_{BM}$	Break points/segments in day-ahead and balancing market bid curve

Indexes

s	Scenario in $\mathcal{S}$
$t/\hat{t}$	Time period in $\mathcal{T}^A$
$r/\hat{r}$	Reservoir in $\mathcal{R}$
j	Water value cut in $\mathcal{J}$
g	Hydro power generator in $\mathcal{G}$
i	Segment in $\mathcal{I}$
k	Thermal generator in $\mathcal{K}$
b	Break point/segment in $\mathcal{B}_{DA}$ or $\mathcal{B}_{BM}$

Parameters

T^{max}	Number of operational time periods (normally 24)
T^L	Length of the time periods (normally 1 hour)
P_s	Probability of scenario s in $\mathcal{S}$
Q^R_{rt}, Q^U_{rt}	Regulated and unregulated inflow
$\overline{Q}^V_r$, $\underline{Q}^V_r$	Upper and lower reservoir level
$\overline{Q}^{\Delta V}_r$, $\underline{Q}^{\Delta V}_r$	Upward and downward reservoir ramping limits as percent of capacity
$\overline{Q}^R_r$, $\underline{Q}^R_r$	Maximum and minimum release
$\overline{Q}^B_r$, $\underline{Q}^B_r$	Maximum and minimum bypass
$\overline{Q}^{\Delta D}_r$, $\underline{Q}^{\Delta D}_r$	Upward and downward discharge ramping limits
$\overline{Q}^S_r$	Spillage cost limit
C^{Spill}_r	Marginal cost of spillage above the spillage cost limit
$T^{D,Lag}_{\hat{r}}$, $T^{S,Lag}_{\hat{r}}$, $T^{B,Lag}_{\hat{r}}$	Time it takes for discharge, spillage and bypass flows from reservoir $\hat{r}$ to end up in downstream reservoir (description in 3.9)

$\underline{Q}_g^D$	Mimimum total discharge for each generator
$\overline{Q}_{gi}^D$	Maximum discharge for each line segment
C_g^{Start}	Generator start up cost
E_{gi}^{Start}	Power per unit discharge at line segment i
$\overline{W}_g$, $\underline{W}_g$	Maximum and minimum hydro power production, respectively
$\overline{W}^{Tot}$	Maximum total hydro power production
$Q_{r,j}^V$	Reservoir level at cut j as percent of total capacity
U_j	Total water value at reservoir levels given by $Q_{r,j}^V$
Π_{rj}	Slope of water value for change in reservoir level r at cut j
C_k^T	Operation cost of thermal generator k per time period
$\overline{W}_k^T$, $\underline{W}_k^T$	Maximum and minimum thermal production
$\tilde{P}_{ts}^{DA}$	Day-ahead market price
$\overline{P}_t^{DA}$, $\underline{P}_t^{DA}$	Upper and lower bid limit for the day-ahead market
P_{ts}^{DA+}, P_{ts}^{DA-}	Price points in supply and demand bid curve for the day-ahead market
$\tilde{P}_{ts}^{BM}$	Balancing market price
$\overline{P}_{ts}^{BM}$, $\underline{P}_{ts}^{BM}$	Upper and lower bid limit for the balancing market
P_{ts}^{BM+}, P_{ts}^{BM-}	Price points in supply and demand bid curve for the balancing market

Continuous variables

q^{V}_{rts}	Reservoir level of r at the end of time period t
q^{R}_{rts}	Released water from r in time period t
q^{S}_{rts}	Spillage from r in time period t
q^{B}_{rts}	Bypass from r in time period t
q^{V+}_{rs}	The sum of discharge, bypass and spillage that will arrive in reservoir r after the the end of the planning horizon
c^{Spill}_{rts}	Spillage cost for spillage from r in time period r
u_s	Water value of final reservoir levels
q^{D}_{gts}	Discharge through g in time period t
q^{D}_{gits}	Discharge in segment i for generator g in time period t
w_{gts}	Hydro power production from generator g
c^{Start}_{gts}	Start up cost for generator g
w_{kts}	Thermal production from generator k
w^{Dump}_{ts}	Produced energy that is not being sold. Dump variable to avoid infeasebility
x^{DA+}_{bts}, x^{DA-}_{bts}	Supply and demand volume in day-ahead market at break point b
y^{DA+}_{ts}, y^{DA-}_{ts}	Accepted supply and demand volume in day-ahead market
x^{BM+}_{bts}, x^{BM-}_{bts}	Supply and demand volume in balancing market at break point b
y^{BM+}_{ts}, y^{BM-}_{ts}	Accepted supply and demand volume in balancing market
y^{IB+}_{ts}, y^{IB-}_{ts}	Positive and negative imbalance volume

Binary variables

γ_{gts}	Generator state: spinning = 1 or not spinning = 0

General notes

In addition to these, many of the variables are given initial values, such as the reservoir level and different flows. An index of 0 for any variable indicates that it is in fact an initial value given as input parameter.

Some conversion factors might also be needed some places in the model.

Since these might vary depending on the input data, they are not included in the description.

Model functions

Objective

$$Obj = -\sum_{s\in\mathcal{S}} S_s \sum_{t\in\mathcal{T}} \sum_{r\in\mathcal{R}} c^{Spill}_{rts} \tag{A.1}$$

$$-\sum_{s\in\mathcal{S}} S_s \sum_{t\in\mathcal{T}} \sum_{g\in\mathcal{G}} c^{Start}_{gts} \tag{A.2}$$

$$-\sum_{s\in\mathcal{S}} S_s \sum_{t\in\mathcal{T}} \sum_{k\in\mathcal{K}} C^{Therm}_{kts} w^{T}_{kts} \tag{A.3}$$

$$+\sum_{s\in\mathcal{S}} S_s u_s \tag{A.4}$$

$$+\sum_{s\in\mathcal{S}} S_s \sum_{g\in\mathcal{G}} C^{Start}_{g} (\gamma_{gTs} - \gamma_{g0s}) \tag{A.5}$$

$$+\sum_{s\in\mathcal{S}} S_s \sum_{t\in\mathcal{T}} \tilde{P}^{DA}_{ts} (y^{DA+}_{ts} - y^{DA-}_{ts}) \tag{A.6}$$

$$+\sum_{s\in\mathcal{S}} S_s \sum_{t\in\mathcal{T}} \tilde{P}^{BM}_{ts} (y^{BM+}_{ts} - y^{BM-}_{ts}) \tag{A.7}$$

Reservoir mass balance

$$\begin{aligned} q^V_{rts} = \quad & q^V_{rt-1s} + T^L(Q^R_{rts} - q^R_{rts} - q^S_{rts} - q^P_{rts}) \\ & + \sum_{\hat{r}\in\mathcal{R}^D_r} \sum_{\hat{t}\in\mathcal{T}^D_{\hat{r}t}} T^L_{\hat{t}} q^D_{\hat{r}\hat{t}s} + \sum_{\hat{r}\in\mathcal{R}^S_r} \sum_{\hat{t}\in\mathcal{T}^S_{\hat{r}t}} T^L_{\hat{t}} q^S_{\hat{r}\hat{t}s} \\ & + \sum_{\hat{r}\in\mathcal{R}^B_r} \sum_{\hat{t}\in\mathcal{T}^B_{\hat{r}t}} T^L_{\hat{t}} q^B_{\hat{r}\hat{t}s} + \sum_{\hat{r}\in\mathcal{R}^P_r} \sum_{\hat{t}\in\mathcal{T}^P_{\hat{r}t}} T^L_{\hat{t}} q^P_{\hat{r}\hat{t}s} \\ & , r\in\mathcal{R}, t\in\mathcal{T}, s\in\mathcal{S} \end{aligned} \tag{A.8}$$

Mass balance between reservoir and generation

$$\sum_{g\in\mathcal{G}} q^D_{gts} = q^R_{rts} - q^B_{rts} + Q^U_{rts} \quad , r\in\mathcal{R}, t\in\mathcal{T}, s\in\mathcal{S} \tag{A.9}$$

Water value cuts

$$u_s - \sum_{r\in\mathcal{R}} \Pi_{rj} (q^V_{rT^{max}s} + q^{V+}_{rs} - Q_{rj}) \leq U_j - U^0 \tag{A.10}$$

End flow between reservoirs

$$q_{rs}^{V+} = \sum_{r\in\mathcal{R}_r^D} \sum_{t=T-T_{\hat{r}}^{D,Lag}+1}^{T} T_t^L q_{\hat{r}ts}^D + \sum_{r\in\mathcal{R}_r^S} \sum_{t=T-T_{\hat{r}}^{S,Lag}+1}^{T} T_t^L q_{\hat{r}ts}^S + \sum_{r\in\mathcal{R}_r^B} \sum_{t=T-T_{\hat{r}}^{B,Lag}+1}^{T} T_t^L q_{\hat{r}ts}^B, \quad r\in\mathcal{R}, t\in\mathcal{T}, s\in\mathcal{S} \tag{A.11}$$

Ramping and discharge limits

$$-T^L \underline{Q}_r^{\Delta V} \overline{Q}_r^V \leq q_{rts}^V - q_{rt-1s}^V \leq -T^L \overline{Q}_r^{\Delta V} \overline{Q}_r^V, \quad r\in\mathcal{R}, t\in\mathcal{T}, s\in\mathcal{S} \tag{A.12}$$

$$-T^L \underline{Q}_r^{\Delta D} \leq q_{rts}^D - q_{rt-1s}^D \leq -T^L \overline{Q}_r^{\Delta D}, \quad r\in\mathcal{R}, t\in\mathcal{T}, s\in\mathcal{S} \tag{A.13}$$

Spillage cost

$$c_{rts}^{Spill} \geq C_{rts}^{Spill}(q_{rts}^S - \overline{Q}_r^S), \quad r\in\mathcal{R}, t\in\mathcal{T}, s\in\mathcal{S} \tag{A.14}$$

Power generated on each line segment in the PQ-curve

$$w_{gts} = \sum_{i\in\mathcal{I}_g} E_{g,i} * q_{gits}^D, \quad g\in\mathcal{G}, t\in\mathcal{T}, s\in\mathcal{S} \tag{A.15}$$

Aggregated discharge across all line segments

$$q_{gts}^D = \sum_{i\in\mathcal{I}_g} q_{gits}^D, \quad g\in\mathcal{G}, t\in\mathcal{T}, s\in\mathcal{S} \tag{A.16}$$

Maximum release and bypass

$$q_{gts}^R \leq \overline{Q}_g^R \tag{A.17}$$

$$q_{gts}^B \leq \overline{Q}_g^B \tag{A.18}$$

Minimum release and bypass

$$q_{gts}^R \geq \underline{Q}_g^R \tag{A.19}$$

$$q_{gts}^B \geq \underline{Q}_g^B \tag{A.20}$$

Minimum discharge and production if spinning

$$q_{gts}^D \geq \underline{Q}_g^D * \gamma gts \tag{A.21}$$

$$w_{gts} \geq \underline{W}_g * \gamma gts \tag{A.22}$$

Maximum discharge and production if spinning (0 if not spinning)

$$q_{gts}^{D} \leq \overline{Q}_{g}^{D} * \gamma gts \tag{A.23}$$

Start up cost

$$c_{gts}^{Start} \geq C_{g}^{Start}(\gamma_{gts} - \gamma_{gt-1s}), \quad r \in \mathcal{R}, t \in \mathcal{T}, s \in \mathcal{S} \tag{A.24}$$

Energy balance between production and market volumes

$$\begin{aligned} \sum_{g \in \mathcal{G}} w_{gts} \sum_{k \in \mathcal{K}} w_{kts} - w_{t,s}^{Dump} = & \\ & y_{ts}^{DA+} - y_{ts}^{DA-} + y_{ts}^{BM+} \\ & - y_{ts}^{BM-} + y_{ts}^{IB+} - y_{ts}^{IB-}, \quad t \in \mathcal{T}, s \in \mathcal{S} \end{aligned} \tag{A.25}$$

Total activated supply in the day-ahead market

$$\begin{aligned} y_{ts}^{DA+} = & \frac{\tilde{P}_{ts}^{DA} - P_{bt}^{DA+}}{P_{b+1t}^{DA+} - P_{bt}^{DA+}} x_{b+1ts}^{DA+} + \frac{P_{b+1t}^{DA+} - \tilde{P}_{ts}^{DA}}{P_{b+1t}^{DA+} - P_{bt}^{DA+}} x_{bts}^{DA+} \\ & , \text{if } P_{bt}^{DA+} \leq \tilde{P}_{ts}^{DA} \leq P_{b+1t}^{DA+}, \quad b = 1, ..., B^{DA} - 1, t \in \mathcal{T}, s \in \mathcal{S} \end{aligned} \tag{A.26}$$

Total activated demand in the day-ahead market

$$\begin{aligned} y_{ts}^{DA-} = & \frac{\tilde{P}_{ts}^{DA} - P_{b-1t}^{DA-}}{P_{bt}^{DA-} - P_{b-1t}^{DA-}} x_{b+1ts}^{DA-} + \frac{P_{bt}^{DA-} - \tilde{P}_{ts}^{DA}}{P_{bt}^{DA-} - P_{b-1t}^{DA-}} x_{bts}^{DA-} \\ & , \text{if } P_{bt}^{DA-} \leq \tilde{P}_{ts}^{DA} \leq P_{b-1t}^{DA-}, \quad b = 2, ..., B^{DA}, t \in \mathcal{T}, s \in \mathcal{S} \end{aligned} \tag{A.27}$$

Bid curve monotonicity day-ahead market

$$x_{bts}^{DA+} \leq x_{b+1ts}^{DA+}, \quad b = 1, ..., B^{DA} - 1, t \in \mathcal{T}, s \in \mathcal{S} \tag{A.28}$$

$$x_{b-1ts}^{DA+} \leq x_{bts}^{DA+}, \quad b = 2, ..., B^{DA}, t \in \mathcal{T}, s \in \mathcal{S} \tag{A.29}$$

Total activated supply in the balancing market

$$\begin{aligned} y_{ts}^{BM+} = & \begin{cases} x_{bts}^{BM+} & : P_{bts}^{BM+} \leq \tilde{P}_{ts}^{BM} < P_{b+1ts}^{BM+} \bigwedge \tilde{P}_{ts}^{DA} \leq \tilde{P}_{ts}^{BM} \\ 0 & : \tilde{P}_{ts}^{DA} > \tilde{P}_{ts}^{BM} \end{cases} \\ & , b = 1, ..., B^{BM} - 1, t \in \mathcal{T}, s \in \mathcal{S} \end{aligned} \tag{A.30}$$

Total activated demand in the balancing market

$$\begin{aligned} y_{ts}^{BM+} = & \begin{cases} x_{b-1ts}^{BM+} & : P_{bts}^{BM-} \leq \tilde{P}_{ts}^{BM} < P_{b-1ts}^{BM-} \bigwedge \tilde{P}_{ts}^{DA} \geq \tilde{P}_{ts}^{BM} \\ 0 & : \tilde{P}_{ts}^{DA} < \tilde{P}_{ts}^{BM} \end{cases} \\ & , b = 2, ..., B^{BM}, t \in \mathcal{T}, s \in \mathcal{S} \end{aligned} \tag{A.31}$$

Bid curve monotonicity balancing market

$$x^{BM+}_{bts} \leq x^{BM+}_{b+1ts}, \quad b = 1, ..., B^{BM} - 1, t \in \mathcal{T}, s \in \mathcal{S} \tag{A.32}$$

$$x^{BM+}_{b-1ts} \leq x^{BM+}_{bts}, \quad b = 2, ..., B^{BM}, t \in \mathcal{T}, s \in \mathcal{S} \tag{A.33}$$

B Mathematical Description of Penalty Functions

Set

$\mathcal{R}^{Tar}$	Reservoirs handled by target level and penalty function.
$\mathcal{P}_r$	Break points on penalty function.

Parameters

P_r^{Max}	Last break point on penalty function.
P_r^{Tar}	Index in $\mathcal{P}_r$ of target reservoir level.
Q_{rp}^{Break}	Reservoir level at penalty function break point as per cent of total reservoir capacity.
C_{rp}	Slope of the penalty function (absolute value).
C_{rp}^{Fix}	Fixed part of the penalty functions.

Variables

c_{rs}^{Pen}	Penalty cost for each reservoir.
c_s^{Tot}	Total penalty cost to be subtracted from objective.

Pre calculations

Calculates the fixed part of the penalty functions.

$$C_{r,P_r^{Tar}}^{Fix} = C_{r,P_r^{Tar}} * Q_{r,P_r^{Tar}}^{Break} * \overline{Q}_r^V/100 \quad , r \in \mathcal{R} \tag{B.1}$$

$$C_{r,P_r^{Tar}+1}^{Fix} = -C_{r,P_r^{Tar}+1} * \frac{Q_{r,P_r^{Tar}}^{Break} * \overline{Q}_r^V}{100} \quad , r \in \mathcal{R} \tag{B.2}$$

$$C_{rp}^{Fix} = C_{r,p-1}^{Fix} + \frac{Q_{r,p-1}^{Break} * \overline{Q}_r^V}{100} * (C_{rp-1} - C_{rp}) \\ , r \in \mathcal{R}, p \in P_r^{Tar} + 2..P_r^{Max} \tag{B.3}$$

$$C_{rp}^{Fix} = C_{r,p+1}^{Fix} + \frac{Q_{r,p}^{Break} * \overline{Q}_r^V}{100} * (C_{rp} - C_{rp+1}) \\ , r \in \mathcal{R}, p \in 1..P_r^{Tar} - 1 \tag{B.4}$$

Model Restrictions

Penalty cost greater or equal to every penalty function at given reservoir level.

$$c_{rs}^{Pen} \geq -C_{rp} * q_{r,TMax,s}^{V} + C_{rp}^{Fix} \quad , r \in \mathcal{R}, s \in \mathcal{S}, p \in 1..P_r^{Tar} \tag{B.5}$$

$$c_{rs}^{Pen} \geq C_{rp} * q_{r,TMax,s}^{V} + C_{rp}^{Fix} \quad , r \in \mathcal{R}, s \in \mathcal{S}, p \in P_r^{Tar}..P_r^{Max} \tag{B.6}$$

$$c_{s}^{Tot} = \sum_{r \in \mathcal{R}^{Tar}} c_{rs}^{Pen} \quad , s \in \mathcal{S} \tag{B.7}$$

C Excel Sheets

Several Excel sheets have been used at different stages of the project work, either to convert data to appropriate formats or to process output data. This appendix show a list of these with a short explanation for each. The Excel sheets are are gathered in the zipped folder "ExcelSheets_OptHydroSched.zip" that accompanies this report.

PriceStatistics.xlsx
Excel sheet use to perform statistical analyses of historical DA and BM prices.

ScenariosNordic.xlsx & ScenariosGermany.xlsx
Excel sheet containing all the price scenarios that are used in the different simulations.

results.xlsx
All results where imported from .txt-files into this sheet and processed to produce the different tables and figures presented in Section 6. The blank sheets contain the imported data with no modifications. The colored sheets contains processed data with cell references to the output data sheets.

PQcurves.xlsx
The PQ-curves are calculated in this sheet. Generator and turbine efficiency curves were copied into the sheet and the Matlab script in Appendix E was used to adjust generator efficiency and output power to correspond shaft power (see Section 5.2.2). Basic Excel functions were then used to calculate the PQ-curves.

D RKOM Market Data

Table 15 contains the available market data [25] as of 19.05.2015 for RKOM-week. There were no trade in RKOM-night. Only weeks with trade in RKOM-H and/or RKOM-B is shown.

Table 15: RKOM-day market data for 2014/2015 from Statnett. Prices displayed are per MW/h. A conversion factor of 8.5 NOK/EUR was used. There were either no trade or no data available for weeks not displayed.

		RKOM-H day			**RKOM-B day**		
Year	Week	Volume [MW]	Price [NOK]	Price [EUR]	Volume [MW]	Price [NOK]	Price [EUR]
2014	50	30	4.5	0.529	170	4.5	0.529
2014	51	0	0	0	240	4.5	0.529
2015	2	90	5	0.588	393	5	0.588
2015	3	290	15	1.765	344	5	0.588
2015	4	410	50	5.882	466	7.52	0.885
2015	5	415	60	7.059	533	9.02	1.062
2015	6	382	90	10.588	376	9	1.059
2015	7	395	40	4.706	481	8	0.941
2015	8	430	40	4.706	349	8	0.941
2015	9	420	40	4.706	358	7.52	0.885
2015	10	105	5	0.588	127	5	0.588
2015	19	70	9.98	1.174	721	9.98	1.174
2015	21	220	9.9	1.165	492	9.9	1.165

E Matlab Script for PQ Calculations

```
% Sist redigert: 22.10 kl. 23:45

function [Done] = CalculatePQcurves(HydroPlant)

%Read output MW from generator efficiency table
GenOut = xlsread('PQcurves.xlsx',HydroPlant,'A4:A11');
%Read generator efficiencies from generator efficiency table
GenEff = xlsread('PQcurves.xlsx',HydroPlant,'B4:B11');
%Read discharge from turbine efficiency table
Discharge = xlsread('PQcurves.xlsx',HydroPlant,'A15:A22');
%Read turbine efficiencies from turbine efficiency table
TurbEff = xlsread('PQcurves.xlsx',HydroPlant,'B15:B22');
%Read head
Head = xlsread('PQcurves.xlsx',HydroPlant,'B14');

%Find the size of the turbine efficiency table
DisSize = size(Discharge,1);
%Initialize the generator input corresponding to each discharge
GenInput = zeros(DisSize,1);

%Calculate the input to the generator for all dicharges
for i = 1:DisSize
    GenInput(i) = 9.81*10^(-3)*TurbEff(i)*Discharge(i)*Head;
end

%Initialize power output and generator efficiency
PQ = zeros(8,1);
N = zeros(8,1);

%For all discharge levels, calculate output power
%and generator efficiency.
for i = 1:DisSize
    %Iterates through the generator efficiency table to find the
    %closest match below the ouput power calculated from the
    %input power
    j = 1;
    while (GenInput(i)*GenEff(j)) >= GenOut(j) && j+1 <= DisSize
        j = j+1;
    end
    if j == 1
        j = j+1;
    end

    %Initialise the temporary ouput power by setting it equal to
    %input power times generator efficiency found above
    TempOut = GenInput(i)*GenEff(j);
    %Interpolate in the generator efficiency table to find
```

```
    %corresponding efficiency
    TempN = GenEff(j-1) + (TempOut-GenOut(j-1))*...
        (GenEff(j)-GenEff(j-1))/(GenOut(j)-GenOut(j-1));

    %Use temporary efficiency to find new output, interpolate to
    %find new efficiency, rince and repeat until the difference
    %between the temporary output and the generator input times
    %the temporary efficiency is less than 0.000001.
    while (TempOut - GenInput(i)*TempN) >= 0.000001
        TempOut = GenInput(i)*TempN;
        TempN = GenEff(j-1) + (TempOut-GenOut(j-1))*...
            (GenEff(j)-GenEff(j-1))/(GenOut(j)-GenOut(j-1));
    end
    %Save the final temporary output and efficiency to PQ and N
    PQ(i) = TempOut;
    N(i) = TempN;
end

%Writes results to excel. The variable "Done" is 1 if writing PQ
%was successful, otherwhise 0.
xlswrite('PQcurves.xlsx',N,HydroPlant,'D15:D22');
Done = xlswrite('PQcurves.xlsx',PQ,HydroPlant,'E15:E22');
return;
```

F Matlab Script for ProdRisk Price Input

```
%Divides price data from 1996 to 2014 into price sections to be
%used in ProdRisk.
priceSec = [];
for year=1996:2014
    prices = xlsread('Excelark\DAprices_NOK',num2str(year),...
        'B1:Y364');
    priceSecTemp = [];
    for i = 0:7:364-7
        sec1 = mean(mean([prices(i+1:i+5,9:11),...
            prices(i+1:i+5,15:17)]));
        sec2 = mean(mean([prices(i+1:i+5,6:8),...
            prices(i+1:i+5,12:14)]));
        sec3 = mean(mean([prices(i+1:i+5,1:5),...
            prices(i+1:i+5,18:22)]));
        sec4 = mean([mean(prices(i+1:i+5,23:24)),...
            mean(prices(i+6:i+7,:))]);
        priceSecTemp = [priceSecTemp;sec1,sec2,sec3,sec4];
    end
    priceSec = [priceSec;priceSecTemp'];
end
```

G Matlab Script for Statistical Analysis of Prices

```
% Function to run statistics on historical prices.
% Input is a 3-column matrix, A, with DA and BM prices in column
% 1 and 2 and the difference between them in column 3. Title is
% the name of the data series.
function diffCount = Statistics(A,Title)
    pngPrint = 1;
    c = size(A,1);
    minDiff = floor(min(A(:,3)));
    maxDiff = ceil(max(A(:,3)));

    %Plots histogram of DA-RK price differences.
    histFig = figure('Name',[Title,': Number of occurences',...
        'for intervals of DA-RK price difference']);
    set(histFig, 'Visible', 'off');
    hist(A(:,3),2*(maxDiff-minDiff));

    savefig(['Figures\',Title,'Hist']);
    % Finds the number of occurencies of each DA-RK price
    % difference, rounded to the nearest integer. Previously
    % used to make histogram plot. May multiply values to
    % split into more intervals.
    diffCount = zeros(maxDiff-minDiff+1,1);
    for i = 1:c
        k = round(A(i,3))-minDiff+1;
        diffCount(k) = diffCount(k)+1;
    end

    % Counts the number of up, down and no regulation for 6
    % intervals around the mean value for the whole price period.
    % Used to check if there is any correlation between DA price
    %  and DA-RK price difference.
    stdAvvik = std(A(:,1));
    middelverdi = mean(A(:,1));
    DAdiffCheck = zeros(6,6);
    for i = 1:c
        if A(i,1) < middelverdi - 2*stdAvvik
            if A(i,1) == A(i,2)
                DAdiffCheck(1,2) = DAdiffCheck(1,2)+1;
            elseif A(i,1) < A(i,2)
                DAdiffCheck(1,1) = DAdiffCheck(1,1)+1;
            elseif A(i,1) > A(i,2)
                DAdiffCheck(1,3) = DAdiffCheck(1,3)+1;
            end
        elseif A(i,1) < middelverdi - stdAvvik
            if A(i,1) == A(i,2)
                DAdiffCheck(2,2) = DAdiffCheck(2,2)+1;
```

```
            elseif A(i,1) < A(i,2)
                DAdiffCheck(2,1) = DAdiffCheck(2,1)+1;
            elseif A(i,1) > A(i,2)
                DAdiffCheck(2,3) = DAdiffCheck(2,3)+1;
            end
        elseif A(i,1) < middelverdi
            if A(i,1) == A(i,2)
                DAdiffCheck(3,2) = DAdiffCheck(3,2)+1;
            elseif A(i,1) < A(i,2)
                DAdiffCheck(3,1) = DAdiffCheck(3,1)+1;
            elseif A(i,1) > A(i,2)
                DAdiffCheck(3,3) = DAdiffCheck(3,3)+1;
            end
        elseif A(i,1) < middelverdi + stdAvvik
            if A(i,1) == A(i,2)
                DAdiffCheck(4,2) = DAdiffCheck(4,2)+1;
            elseif A(i,1) < A(i,2)
                DAdiffCheck(4,1) = DAdiffCheck(4,1)+1;
            elseif A(i,1) > A(i,2)
                DAdiffCheck(4,3) = DAdiffCheck(4,3)+1;
            end
        elseif A(i,1) < middelverdi + 2*stdAvvik
            if A(i,1) == A(i,2)
                DAdiffCheck(5,2) = DAdiffCheck(5,2)+1;
            elseif A(i,1) < A(i,2)
                DAdiffCheck(5,1) = DAdiffCheck(5,1)+1;
            elseif A(i,1) > A(i,2)
                DAdiffCheck(5,3) = DAdiffCheck(5,3)+1;
            end
        elseif A(i,1) >= middelverdi + 2*stdAvvik
            if A(i,1) == A(i,2)
                DAdiffCheck(6,2) = DAdiffCheck(6,2)+1;
            elseif A(i,1) < A(i,2)
                DAdiffCheck(6,1) = DAdiffCheck(6,1)+1;
            elseif A(i,1) > A(i,2)
                DAdiffCheck(6,3) = DAdiffCheck(6,3)+1;
            end
        end
    end
    % Converts above numbers to percentages.
    for i = 1:6
        for j = 1:3
            DAdiffCheck(i,j+3) =...
                100*DAdiffCheck(i,j)/sum(DAdiffCheck(i,1:3));
        end
    end

    % Counts the number of hours with up, down and no regulation
    % for each day and calculates the average DA price for that
    % day. Used to make scatter plot to check for correlation
    % with DA price and DA-RK price difference.
    dayCount = zeros(c/24,4);
```

```
    for i = 1:24:c
        for j = 0:23
            if A(i+j,3) == 0
                dayCount((i+23)/24,3) = dayCount((i+23)/24,3)+1;
            elseif A(i+j,3) < 0
                dayCount((i+23)/24,2) = dayCount((i+23)/24,2)+1;
            elseif A(i+j,3) > 0
                dayCount((i+23)/24,4) = dayCount((i+23)/24,4)+1;
            end
        end
        dayCount((i+23)/24,1) = mean(A(i:i+23,1));
    end
    scatterDown = figure('Name',[Title,...
        ': Number of down-regulations at each price level']);
    set(scatterDown,'Visible','off');
    hold on;
    title('Number of down-regulations at each price level',...
        'FontSize',20);
    xlabel('Average daily DA-price [EUR/MWh]','FontSize',16);
    ylabel('Number of down-reguations','FontSize',16);
    scatter(dayCount(:,1),dayCount(:,2));
    savefig(['Figures\',Title,'ScatterDW']);

    scatterNo = figure('Name',[Title,...
        ': Number of no regulation at each price level']);
    set(scatterNo,'Visible','off');
    hold on;
    title('Number of no regulation at each price level',...
        'FontSize',20);
    xlabel('Average daily DA-price [EUR/MWh]', 'FontSize',16);
    ylabel('Number of no reguation','FontSize',16);
    scatter(dayCount(:,1),dayCount(:,3));
    savefig(['Figures\',Title,'ScatterNO']);

    scatterUp = figure('Name',[Title,...
        ': Number of up regulations at each price level']);
    set(scatterUp,'Visible','off');
    hold on;
    title('Number of up-regulations at each price level',...
        'FontSize',20);
    xlabel('Average daily DA-price [EUR/MWh]','FontSize',16);
    ylabel('Number of up-reguations','FontSize',16);
    scatter(dayCount(:,1),dayCount(:,4));
    savefig(['Figures\',Title,'ScatterUP']);

    if  pngPrint == 1
        saveas(scatterDown,['Figures\',Title,'ScatterDW'],'png');
        saveas(scatterNo,['Figures\',Title,'ScatterNO'],'png');
        saveas(scatterUp,['Figures\',Title,'ScatterUP'],'png');
    end
```

H Scatter Plots for Regulation Trend Analysis

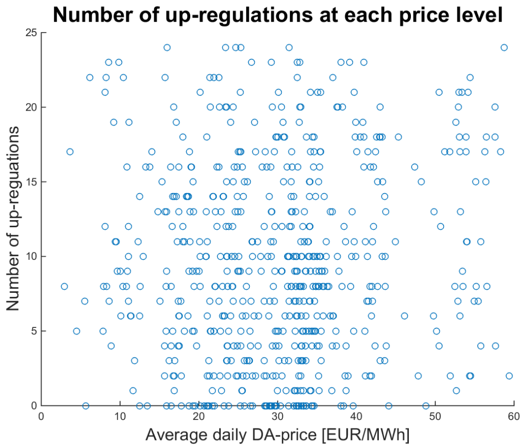

Figure H.1: Number of up-regulations each day as function of average DA price the respective day, week 18-39.

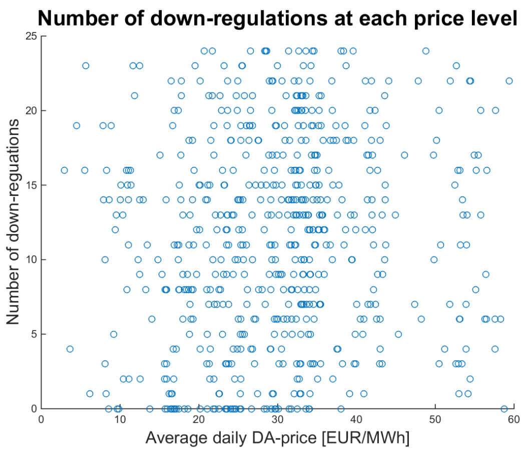

Figure H.2: Number of down-regulations each day as function of average DA price the respective day, week 18-39.

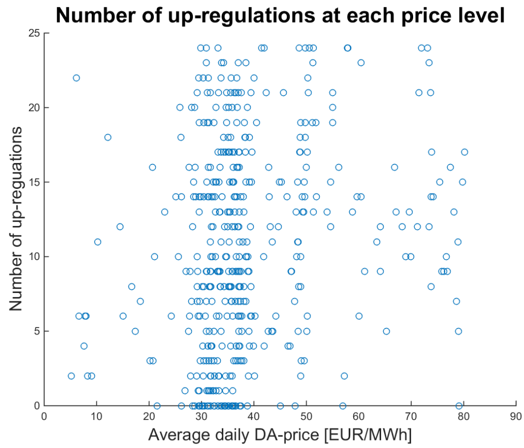

Figure H.3: Number of up-regulations each day as function of average DA price the respective day, week 40-52.

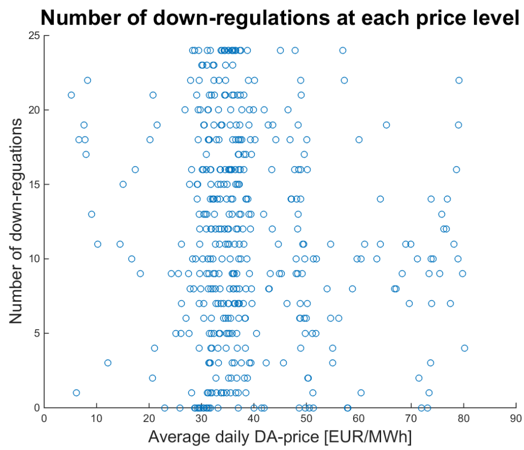

Figure H.4: Number of down-regulations each day as function of average DA price the respective day, week 40-52.