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Quantitativ Analysis of Bidding Strategies and Decision Parameters

Short-term Hydropower Scheduling

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Submission date: June 2014
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PREFACE

This thesis is written on behalf of the final course *"TET4905 Energy Use and Energy Planning, Master Thesis"* to fulfill the requirements for a Master of Science degree in Energy Systems Planning at the Norwegian University of Technology and Science (NTNU), Department of Electric Power Engineering. The work has been done in cooperation with Norway's largest power producer, Statkraft, and inspired by ongoing research and changes in the Nordic power market.

I would like to thank my supervisors Professor Olav Bjarte Fosso (NTNU) and Dr. Tellef Juell Larsen (Statkraft) for their patience, and helpful assistance, as well as their trust in letting me work relatively independently. In addition I would like to thank Statkraft in general for providing necessary tools and data, and for letting me work at their departments in Oslo and Trondheim. It has been a great experience to get to know the operational environments in Statkraft, while working with my thesis. Arnstein Kvande (Statkraft) deserves a big thanks for helping me with useful VBA-programming. I would also like to use the opportunity to thank Fredd Kristiansen (Statkraft) for his lectures regarding hydropower physics, as well as proof-reading my report.

Per Arne Vada (Statnett), a fellow M.Sc. student at NTNU, does also deserve a big thanks for proof-reading my report, despite a quite hectic period for both of us prior to the deadline of submission. I would also like to thank Stein-Erik Fleten (NTNU) and Tor Reier Lilleholt (Markedskraft) for useful inputs during the initial phase of this work.

Martin Kristiansen
Trondheim, June 2014.

ABSTRACT

Norwegian hydropower producers bid to sell tomorrows power in the day-ahead auction called Elspot, at the Nordic power exchange, Nord Pool Spot. Price and inflow are stochastic variables, as well as important decision parameters, in the short-term production scheduling. Market analysts evaluate the forecasts continuously as the variables become revealed through their actual values in the future. This allows us to see how precise they were, but not how it affected the allocation of production and water, and most importantly the producers profits. This thesis will evaluate the significance of these profits with a deterministic optimization model (SHOP), where historical spot prices are used as an optimal reference for the price forecasts used to calculate price independent day-ahead bids. Hence, the results will represent the theoretical improvement potential of price forecasts, as well as the greatest potential value of using a stochastic model.

Three river systems has been analyzed, diversified with respect to capacity and flexibility, and the results shows that the *maximum theoretical* improvement potential, relative to the optimal spot sales, varies between 0.7480 % and 1.7825 %. The lowest- and highest improvements are found for the smallest- and largest river system, respectively. The average improvement potential for the *operative* price forecasts spans from 0.0531 % to 0.2397 %, for the same systems. The significance of the price forecasts varies throughout the year, and it is generally highest when the volatility- and level of price, is high. As for larger price areas the theoretical improvement potential varies between 0.1404 % and 1.4685 %, where NO2 gives the highest potential, and NO3 the lowest.

Price uncertainty is proven to have greater impact on short-term scheduling than uncertainty about inflow, due to the fact that inflow uncertainty only affects the income when calculating forced production to avoid potential spillage. Hence, river systems with a low degree of regulation are more exposed to inflow uncertainty. However, the extreme scenarios in both cases gives nearly identical feasible improvement potential, given a system that is exposed for spillage risk.

SAMMENDRAG

Norske vannkraftprodusenter byr energien de har planlagt å produsere inn til kraftmarkedet én dag i før det faktisk utveksles, i det Nordiske Elspot markedet som opereres av Nord Pool Spot. Pris og tilsig, som er blant de viktigste beslutningsparameterne for vannkraftplanlegging på kort sikt, er stokastiske variabler som kan avvike fra sine prognoserte verdier. Analytikere måler kontinuerlig hvor godt disse prognosene treffer faktisk verdier, og korrigerer deretter sine modeller. Det som ikke fanges opp i slike målinger, er effekten det har på energidisponeringen, og ikke minst inntektene, til en vannkraftprodusent. Denne oppgaven vil presentere en metodikk for å måle denne inntektseffekten, samt kvantifisere måltall med hensyn til pris, tilsig og andre relevante beslutningsparametere.

Metodikken går ut på å gjenskape historiske, prisuavhengige anmeldingssituasjoner med den deterministiske modellen SHOP (Short-term Hydropower Optimization Program), hvor tilknyttede prisprognoser blir sammenliknet med sin optimale referanse. Den optimale referansen for en prisprognose vil i dette tilfellet være den realiserte spottprisen.

De respektive inntektene fra beslutningsparameterne som måles, vil avvike fra sin optimale referanse, og den optimale referansen vil alltid gi høyest inntekt. Så differansen vil egentlig tilsvare tapte inntekter på å gjøre en beslutning som ikke var optimal. For prisprognoser vil dette avviket altså representere et forbedringspotensial, som også kan ansees som den maksimale potensielle nytten av å benytte en stokastisk modell, fremfor en deterministisk. En stokastisk modell vil aldri kunne oppnå det fulle forbedringspotensialet, men det gir en god indikasjon på hvor mye den teoretisk sett kan være verdt.

De såkalte etteranalysene i denne rapporten viser til maksimalt løsbare forbedringspotensialer i intervallet 0.7480 % til 1.7825 %. For prisprognosene vil dette potensialet (forhåpentligvis) være lavere , og rapporten viser til følgende verdier; 0.0531 % til 0.2397 % for de samme vassdragene. For prisområder endte den potensielle nytte et sted mellom 0.1404 % og 1.4685 %, hvor NO2 har det største forbedringspotensialet og NO3 det laveste.

CONTENTS

ABBREVIATIONS

CPLEX – Solver used by SHOP

EMPS – EFI’s Mulit-Area Power market Simulator (global analysis)

EOPS – EFI’s One-Area Power market Simulator (local analysis)

EUR – European currency (EUR 1 = NOK 8.34, 13.11.2013)

FAME – Forecast, Analytics, Modeling and Estimation (forecasting model used by Statkraft)

LTM – Long-term Models (EMPS and Seasonal model)

masl – Meters above sea-level

MC – Marginal Costs

MO – Market Operator (Nord Pool Spot)

MW – Mega Watt (power, J/s)

MWh – Mega Watt hour (energy, J => 3600 MJ)

NVE – Norwegian Water Resources and Energy Directorate

RoR – Run-of-River

SHOP – Short-term Hydro Optimization Program

SPOTON – Statkraft’s program for calculating day-ahead bids

SRMC – Short run marginal cost

STM – Short-term Model (SHOP)

TSO – Transmission System Operator (Statnett)

WV – Water Value

1 INTRODUCTION

Norwegian hydro-power producers bid to sell their production in a day-ahead electricity market which is cleared one day before the physical exchange of power. Uncertainty about market prices and reservoir inflows, both for the next day and distant future, has a significant influence on the participant's short-term water management. Due to the increasing amount of intermitted power, like solar and wind, being introduced to the Nordic power system, these uncertainties become even more influential and the power producers may want to improve their bidding strategies, and models by meeting these challenges.

This master's thesis is a continuing work on a methodology initiated in a project work (autumn 2013) together with Statkraft. The scope of the thesis is to use this methodology to investigate the economic effect of stochastic variables as price and inflow, as well as other decision parameters associated with short-term hydropower scheduling. The results that are carried out from this report can be used to evaluate the following short-term energy management related topics:

- The economic significance of price- and inflow forecasts.
- The economic significance of other short-term decision parameters
- Day-ahead bidding strategies under certain market conditions
- Theoretical improvement potential of using a stochastic model, instead of a deterministic model.

Most hydropower producers use a deterministic model, meaning that both price and inflow are treated as known parameters. During the last few years there has been done research on stochastic optimization models, for the same applications as those mentioned above (Fleten, Klæboe, Aasgård). The income, or profits, from the stochastic models are often benchmarked with a deterministic model with varying improvements in the range of 0.5-2 %. Instead of measuring income deviations between the respective types of modelling, this report will focus on revealing the maximum, theoretical potential that can be achieved with a stochastic model, as indicated by Figure 1. This is done by re-creating historical scenarios with forecasted- and actual data, e.g. for price and inflow, and comparing the income-effect.

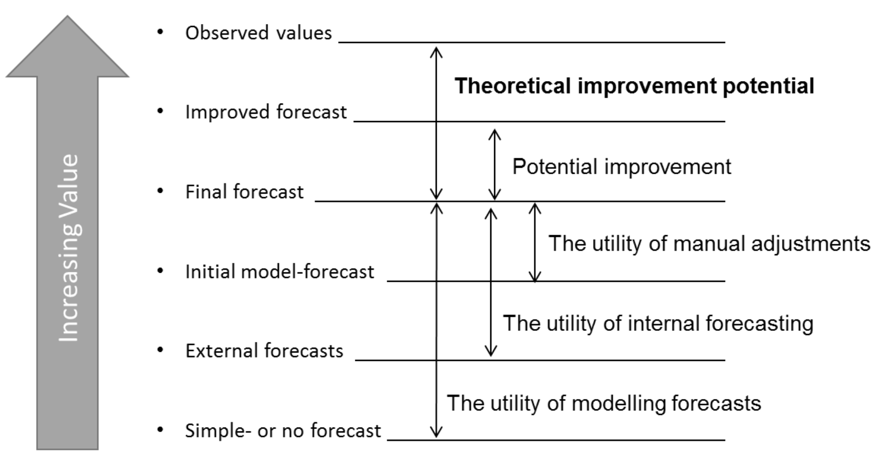

Figure 1 - Conceptual illustration for the methodology framework (Larsen, T. J., 2013)

The analyses of theoretical improvement potential is pursued as a case study with respect to extreme-, and normal-, market conditions accounting for price volatility, price levels, and e.g. other influential factor like wind power production. Seasonal characteristics are also being analyzed. Hence, one can see if the significance of price forecasts varies with the hydrological balance and other market conditions. This approach is considered as a better alternative than random optimizations, due to both the lack of script possibilities, and an outline for discussions of the results.

The layout of this report is as follows: Section 2 represents a short review of the ongoing research concerning bidding strategies and stochastic modelling of short-term hydropower scheduling, before a general introduction to the hydropower scheduling hierarchy, Nordic power market, and SHOP, in Section 3. Then the methodology and supplementary excel-programs are presented in Section 4, followed by a consistency-test of the methodology and illustrative SHOP calculations in Section 5. A fundamental market analysis of the Nordic power market during the year 2013 is pursued in Section 6 to establish cases for the SHOP calculations and discussions later in the report. The case studies in Section 8 are introduced by a description of selected river systems in Section 7. Concluding results within the scope of work are discussed in Section 8, among other relevant analyses. The report is carried out by a conclusion and recommendations to further work in Section 9 and Section 10, respectively.

2 LITERATURE

Available literature directly appealing to the problem description of this thesis is very limited, but to set the objective with the thesis in perspective it is highly relevant to present the research activity considering to take uncertainty into account by making deterministic models, stochastic.

Aasgård and Andersen (2013) has developed a stochastic mixed-integer model for optimizing bids and scheduling for the short-term energy management. Their model is developed for Norwegian price-taking producers that participates in the day-ahead market Nord Pool Spot with a relatively complex system description reflecting a realistic case study. The results that was carried out shows that the stochastic model gives 0.6 % higher total profits compared with a deterministic model used in the industry, on average over a longer period of time. The model is based on previous work done by Fleten and Kristoffersen (2007) who reported increased profits in the range 7-9 %, but probably compared with a more naive benchmark for the deterministic model, as well as a simpler system description relaxating the optimization problem (increasing feasible solutions space). None of the authors considers a producer with market power.

In search of an overview of the ongoing research Klæboe and Fosso (2013) emphasises the need for improved bidding strategies in addition to a review of studies on optimal bidding where sequential markets are taken into account. When modelling such markets as the balancing- or regulating market they stress the current lack of price-volume couplings when considering market mechanisms and potential market power among the participants. The motivation for a good bidding strategy remains by describing three major trends in The European power market; deregulation, renewable intermittent energy, and integration of other power markets. The two latter trends will be further pursued in the market analysis section in this report, allowing us to quantify comparative impacts on the bidding strategies through a commercial optimization model for short term scheduling.

The turnover in subsequent markets are expected to increase because of the increasing uncertainties and deviations between estimated- and actual production/consumption with respect to the commitments made in the day-ahead market. Vardanyan and Amelin (2011) presents interesting views on the penetration level of wind power, generation mix, and grid size. Because of hydropower producer's flexibility and capacity to adjust production very fast, the benefits from cooperating wind- and hydropower can be beneficial, both from a grid- and economic perspective. These benefits can most likely be achieved in a sequential market.

The same authors have done a sensitivity analysis (2012) of short-term hydropower scheduling considering uncertainty in both price and inflow, and conclude that impact of including price uncertainty in the model is higher than that of inflow level uncertainty. It is also proven that the value of stochastic solution (VVS) is greater for smaller and less flexible reservoirs than it is for large and flexible reservoirs. It would be interesting to purse this observations in a bidding strategy context comparing the potential economic profits. This kind of analysis can be assessed during seasonal couplings when there is a relatively high probability of running a small reservoir empty or full.

As SHOP (a deterministic program) will be used in this master thesis, possibilities for including, or measuring, the value of stochastic variables has been investigated. One solution is Progressive Hedging which solves stochastic problems described as a scenario-tree (Fleten, 2014). The idea is to solve one and one scenario, and include a sort of penalty cost for deviations between the solutions which is supposed to be equal (e.g. the bidding variables; price). Recent research regarding this method applied to hydropower scheduling can be found from the author Montreal Gendrau. It is challenging to implement such algorithms in SHOP but a few manual operations is doable.

> *"The progressive hedging algorithm (PHA) is especially well suited when a new stochastic optimization model must be built upon an existing deterministic optimization model (DOM). In such case, scenario sub-problems can be resolved using an existing DOM with minor modifications."* (Gendrau, 2013)

Bakkevig and Statkraft Energi (2005) can be viewed as a starting point for analysing bidding strategies in this master's thesis, where they present methods for making robust spot-bidding with SHOP. The author describes two different approaches, linearization- and stepwise coupling of "break points", to calculate the bid matrix with respect to the production plans given through price-scenario optimization in SHOP. The price scenarios are based on the best available price forecast and adjusted with respect to price level and/or -profile, which again should cover the possible outcome of the stochastic spot price and appurtenant optimal production. Anyway, the results shows that scenario based bidding with SHOP can be very effective and robust, compared with operational bidding (SPOTON), and it concludes with linearization as the best method for construction of the bid matrix with respect to a comparison of market commitments from the different methods. This report will pursue this conclusion by evaluating the effect on SHOP's objective function; maximizing profits.

3 THEORY

This chapter will present a theoretical fundament for understanding the environment for the research provided in this thesis. An introduction to hydropower scheduling, the power market, and the short-term hydropower optimization program, SHOP, is presented in the following sub-sections. Fosso et al. (2002) is a highly recommended supplement for this Chapter if the reader is curious about the framework for hydropower modelling, couplings of the models, and risk management related to price, inflow, and demand.

3.1 HYDROPOWER SCHEDULING

Starting with the general physics of hydro power generation (3.1.1) one can see that the production of electric power is dependent on the overall efficiency (η), water density (ρ), volume-flow (Q), gravity (g) and height difference between inlet- and outlet water surface (h). The height difference varies with the water level in the reservoirs between the regulated points LRV (lowest level) and HRV (highest level), due to environmental restrictions provided by NVE[1]. The reservoirs are often located with respect to a trade-off between inflow catchment-area, and meters above sea level (masl). For example, hydroelectric generation from reservoirs placed at high altitude may have poor inflow catchment and small reservoirs, but a height compensating for same power potential as a reservoir with lower height and increased inflow catchment. A commonly used notion is head. Head is the energy per unit mass of water and is related to the velocity of moving water (or proportional with the height in case of static head). (Doorman, 2013).

$$P = \eta \rho Q g h \qquad (3.1.1)$$

Norwegian hydropower producers operates in a deregulated electricity market with strong exchange capacities with neighboring countries. Although most of the domestic production is hydro power, the scheduling must also take thermal production into account because of the interconnections, resulting in a hydro-thermal system. In addition to the physics of hydroelectric power generation, it makes the scheduling challenging with respect to water travelling in both time and space. The objective for every producer in this market environment is to maximize their profits, which basically is the sum of short-term profits and expected future income from the water stored in the reservoirs (Equation 3.1.2). The mathematical formulation provided below is meant to give a basic impression and is highly simplified, among other things it is assuming independent water values (opportunity costs).

$$Max\left[\sum_{t=1}^{Tk}\left(p_t \cdot \left(q_{s,t} - q_{p,t}\right) - c_{start,t} - c_{penalty,t}\right) + R_T\right] \qquad (3.1.2)$$

T_k = Total amount of time-steps (192 hours in SHOP)

[1] NVE (Norwegian Water Resources and Energy Directorate) is a directorate under the Ministry of Petroleum and Energy.

p_t	= Price [EUR/MWh] at time step t
$q_{s,t}$	= Quantity sold [MWh] at time step t
$q_{p,t}$	= Quantity purchased [MWh] at time step t
$c_{start,t}$	= Start-up costs [EUR] for starting a unit at time step t (including a binary variable 1/0; on/off)
$c_{penalty,t}$	= Penalty function, costs [EUR] (e.g. for exceeding given boundaries)
R_T	= End-reservoir value [EUR] at the last time step T (e.g. Volume [MWh] multiplied with the future water value [EUR/MWh], at time step T)

General microeconomic theory for a competitive market implies that optimal production is achieved when the market price is equal to the marginal cost of producing one more unit of energy, EUR/MWh (Wangensteen, 2007). However, hydropower production is a bit more complicated than that since it often consists of complex system descriptions and enormous water reservoirs that can take up to several (5-6) years to fill with normal inflow[2]. The possibility for energy storage in water reservoirs leaves us with opportunity costs, known as expected water values.

Time horizons spanning over several years leads to the need of long term energy management. The hydropower scheduling problem is therefore divided into a scheduling hierarchy depicted in Figure 2; long-, seasonal- and short term scheduling. Each step in the hierarchy consists of its own model, which is coupled together as indicated by the arrows in the figure. The long-term model (LTM) is stochastic and provides the seasonal model(s) with price forecasts, end-reservoir level and water values for an aggregated system (country, price area etc.) with weekly time resolution. This information is thereby processed in a multi-scenario, deterministic seasonal model with higher level of detail and weekly time resolution; resulting in water values for each individual reservoir in the aggregated system (from the LTM). The long-term strategy is now broken down, and coupled, to the short-term, deterministic optimization model (STM). This report will focus on short term energy management, but the following paragraphs will also highlight the briefly mentioned strategy-coupling in the hierarchy.

[2] Normal inflow is the average inflow that has been historically measured.

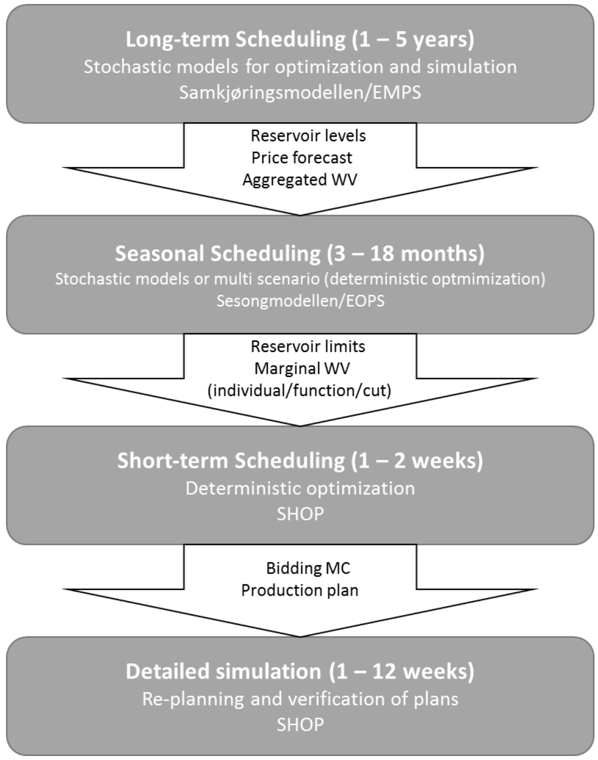

Figure 2 - Hydropower production scheduling hierarchy

3.1.1 The Long-term Model

The long term objective is to manage all resources in an optimal way that fulfil the objective function, which is maximization of economic profits. Expansion planning, revisions, and planned outages are some factors that are accounted for in the long-term model within the defined system boundaries. The system boundaries are chosen as large as possible, and could for example be an extended version of the Nordic region. The modelling beyond this boundary is generalized. The most common LTM in Norway is developed by SINTEF (earlier known as EFI). It consists of a stochastic optimization model and is known by the name EMPS (Efi's Multi-area Power market Simulator).

The model is divided into three phases; first a strategy phase which aggregates different parts of the system within the defined system boundaries and execute simulations that provides possible water values and price forecasts up to 10 years (or 5 years at Statkraft) into the future with weekly time resolution. The second phase is mainly simulations of water tapping and water balance between the reservoirs which is used to give the third phase, the seasonal model, end reservoir restrictions as a framework for the more detailed problems. In addition to this, Statkraft use the water value matrixes and send it to the NLN model[3].

[3] The NLN model is a more detailed seasonal-/short-term, deterministic model. It is run for the next four weeks with hourly time resolution. It optimizes supply and demand within every price area and generates price forecasts that are used in the seasonal- and short-term model.

The LTM is linked with the seasonal model either at the end of the winter before the snow starts melting, or in the autumn when precipitation starts coming as snow. The strategic choice is often dependent on the degree of regulation of the reservoirs (Appendix I). E.g. if the reservoir has a low degree of regulation (<30 %) one should choose the latter coupling in the autumn (for actual scheduling in e.g. February), otherwise April one year ahead (Doorman, 2013).

3.1.2 The Seasonal Model

The seasonal model comprises a more detailed system description and can therefore calculate individual water values within one year horizon and weekly resolution. The objective function in the model is to maximize revenues from each water system formulated as a deterministic optimization problem.

The water values are calculated with respect todays reservoir level and a large number of different inflow- and price forecasts (about 80 different scenarios in Statkraft). Each scenario simulates full production in as many hours needed to reach a certain reservoir level at the end of the optimization period (Doorman, 2013). E.g. if one is not able to use enough water to avoid overflow even with full production in all hours, the marginal MWh will be spilled and the water value becomes zero. The resulting water values for each individual reservoir is thereby used in the short term scheduling model, SHOP.

3.1.3 The Short-term Model

Short-term optimization of hydropower scheduling consists of even more detailed- and complex system descriptions such as efficiency, head loss, reservoir inflow, water routes, outages, and water traveling in both time and space. SHOP, or Short-term Hydropower Optimization Program, is a commonly used model for this use. The model is formulated as a deterministic optimization problem by treating the stochastic variables, like price and inflow, as known parameters. It is however possible to approximate stochastic solutions with a multi-scenario analysis, which allow the user to get an impression of how the resources are utilized with respect to different level of inflow and/or price. E.g. during a normal winter, the inflow is relatively low and the need for many scenarios is reduced. On the other hand, with extreme cold temperatures or extreme inflow forecasts, the market price becomes volatile and the need for many scenarios increase as the uncertainty increase.

> *"As we know, there are known knowns, there are things that we know we know. We also know there are known unknowns, that is to say, we know there are some things we do not know. But there are also unknown unknowns, the ones we don't know we don't know."*
>
> (Betrand Russel, 1964)

Statkraft's long term energy management framework for short-term scheduling is provided through the seasonal model in form of individual water values and end reservoir restrictions. There are several methods to couple the water values which will be discussed later in Section 3.3. The short-term model is mainly used for bidding in the day-ahead- and intraday markets, as well as for optimal scheduling of the volume commitments from Nord Pool. SHOP can also be used for several other applications, among them decision- and sensitivity analysis, which is the case for this thesis.

3.2 THE POWER MARKET

This sub-section provides an overview of the power markets disposable for Norwegian participants. The markets are distinguished between two types; one financial- and one physical part, as illustrated in Figure 3 where the red dot marks the finalized exchange of physical energy. The definition of these markets are provided by (Wangensteen, 2011) and (Nordpool, 2013), and is in a general matter presented in the following paragraphs.

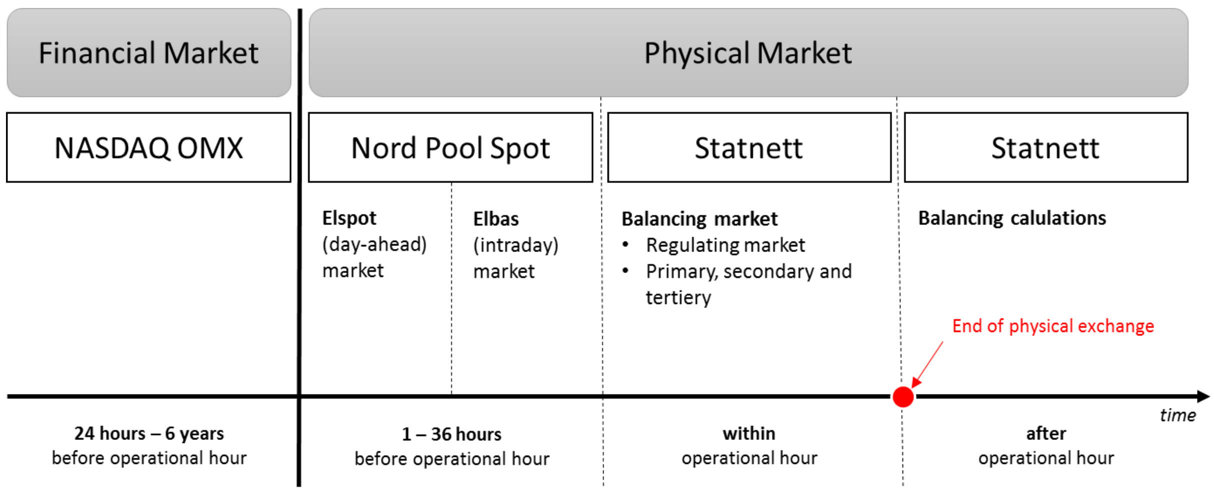

Figure 3 - An illustration of the financial- and physical power market in Norway

3.2.1 Financial Market

As described in the previous sub-section, the hydropower scheduling is organized in a hierarchy with respect to different time horizons. The long-term energy management is organized in a portfolio with a dual aim of both managing the long-term risk in the Nordic Asset portfolio while at the same time maximizing the long term value of the portfolio within given risk limits. The two main risks are volume risk related to varying inflow and price risk related to volatile prices. The portfolio includes long term industrial contracts and trades in the financial electricity market. The management decisions are amongst others based on the same fundamental price forecasts as for dispatch decisions.

NASDAQ OMX is a financial market where participants can trade contracts on delivery of electricity from one day- to 6 years into the future (NASDAQ OMX, 2014). This kind of trading is often referred to as hedging and risk management in form of securing *fictive* sales, or purchases, of energy at a fixed average price for the period defined in the contract. Fictive meaning that there is no physical exchange, only a financial settlement. For example, if it is important for a producer to sell their power at a certain price, let's say for the next year, they can buy a contract for that year guaranteeing the bid price (provided by potential buyers). This may be further favourable for the producer if the average spot price for the following year turns out to be lower than the closing price for the contract, and vice versa for the consumer if the spot price gets above the contract's clearing.

Pricing of financial instruments are determined with respect to an underlying asset, which in this case is the system spot price. Financial instruments that can be traded are forwards, futures, options and contracts for difference (also known as CfD). Forwards and futures are used to hedge against system price volatility with a *contract to buy or sell* at a fixed price, while options is more like an insurance where you pay an amount of money for the *option to buy or sell* at a fixed price. The most common (European[4]) options are put- and call options, analogue to short- and long positions with the underlying asset (bear and bull). CfD's are forward contracts with a premium covering the difference between two underlying assets, for example system- and area price, which enables to e.g. bet on if the area price is going to be higher, or lower, than the system price.

3.2.2 Physical Market

As shown in Figure 3, the physical market consists of a day-ahead-, intraday-, and balancing market. These markets are highly relevant for short-term hydropower scheduling, and therefore also within the scope of work in this thesis.

For short-term energy management, in form of physical power trading, is (in Norway) done in the Nordic spot market (Elspot) which is operated by Nord Pool Spot AS. Participants in this market submits their buy- and sell bids at 12:00 one day before the physical exchange. The bids are delivered as a bid matrix which address different price-volume relationships for every hour (24 hours) the following day. The market operator aggregates supply and demand after the bids are received, and clears the system price around 13:30 the same day. The system price is calculated with assumptions about unlimited transmission capacity in the system (Wangensteen, 2011). However, since the power flow is subject to capacity constraints the market operator calculates area prices. Price areas are established to balance the system with respect to transmission capacity. For instance, prices are lowered in surplus areas and raised in deficit areas to facilitate the power flow balance.

After the spot market is cleared each producer is obligated to deliver their volume commitments the next day. The committed volumes are a result of an interpolation between the nearest price-volume bids (Nord Pool, 2013), for example if the spot price is cleared at 40.5 EUR/MWh for a given hour where the nearest bids given are 40 EUR/MWh at 100 MW and 41 EUR/MWh at 110 MW, the committed volume to the market becomes 105 MW like the calculation below illustrates.

$$100\ MW + \frac{40.5 - 40}{41 - 40} \cdot (110 - 100)\ MW = 105\ MW$$

Since the bids are delivered up to 12 + 24 = 36 hours before actual production and consumption of electric power there is always some uncertainty that can affect the balance. In case of such imbalances (outage, revision, demand shift, intermitted power etc.) the participants can contribute in sequential markets; the intraday- (Elbas) and the balancing market. Trading at Elbas can be done continuously up to one hour before physical delivery, which enables producers to cover any deviations from their commitments.

[4] Options are usually categorized as European- or American options. The main difference is that European options only can be exercised at "exercise date" while American options can be exercised anytime. The latter option gives "better insurance" and more flexibility, hence a bit more expensive.

Participants can therefore actively trade and match their commitments up to one hour before the physical exchange of power. Necessary adjustments and trades after this, or within the hour of operation, are balanced by the transmission system operator (TSO), which in Norway is Statnett. The TSO's responsibility is to balance the instantaneous production and consumption which is done in a regulating market. The regulating market is organized in such way that the producers can commit available production capacity to the TSO after Elspot is cleared, and prior to the operating hour.

The volumes traded at Elbas (0,228 TWh) and the regulating market (1,224 TWh) represents about 1.67 % of the Elspot volume during the year 2013, and are probably caused by imbalances due to regulations from the TSO; saying that Elspot bids must be in accordance with expected supply/demand (Statnett, 2014). Today's turnover does not give strong incentives for participating in the sequential markets. However, uncertainty that comes along with intermittent power production is expected to increase the turnover volumes in subsequent markets (Vardanyan, 2011), hence it may be possible for minor bidding strategy adjustments that utilizes this trend to make potentially, favourable trades. A review of these volume-trends, and characteristics, within sequential markets will be presented in Section 6.

3.3 Short-term Hydropower Optimization Program (SHOP)

A review of the commercial STM will be given in this section. This is the model that has been used for analyzing the problems addressed in this thesis, and the scope of this section is to present all the relevant information that is necessary to interpret the methodology and the results later in the report. Starting with a general introduction to its applications, followed by the coupling with the LTM, mathematical model structure, river system topologies, calculation of production-water-discharge relationship (PQ-curves) and marginal costs (MC), and automatic generation control (AGC). The content presented in this section is based on far more detailed information that can be found in (Fosso, 2002), (Fosso, 2013), and Chapter 9 in (Doorman, 2013).

SHOP is designed for short-term optimization of hydropower scheduling, hence the same applications that were briefly mentioned in Section 3.1.3. Due to the physical complexity of hydropower systems and the level of detail needed for short-term scheduling, the dimension of the problem becomes significant. Spanning from a large number of reservoir balance equations for every time step, variables within the reservoirs, inequalities like ramping and start costs, to couplings with long term strategy, inflow, and the power market.

3.3.1 Coupling with the Seasonal Model

SHOP is coupled to the seasonal model through water values which allows the program to see the expectations for the future and decide how to utilize available resources within the nearest future. The water values can be viewed as an opportunity cost, and they can be calculated by the following three (four) methods:

1. Independent water value
    - Referred to the reservoir level in the end of the SHOP-optimization period, but independent of the actual reservoir level at that point of time. It is also independent on other reservoir levels in the system.

2. Independent water value function
   - Described as a function of actual reservoir filling in the end of the SHOP period, and not only an average value for potential reservoir levels (like the first method).

3. Dependent water value (cuts)
   - A set of linear restrictions, called cuts, which is based on maximization of income from both the SHOP period, and future expectations beyond the coupling point, for a given end-reservoir level and possible combinations within a river system; multiple reservoirs.

4. Alternative: Water value priced as a real options
   - The option to delay power production. Exercised with respect to the current spot price and the expected opportunity loss that arises if water used at a later moment. The value of delaying production increase as the reservoir level decrease.

Descriptions of point one, two, and three are referred to an ongoing project evaluating use of water value couplings in SHOP, within Statkraft (Statkraft, 2014). This is not an open-source reference but the same explanations can be found in (Fosso, 2002) and (Doorman, 2013), except for the second method. The fourth method is only mentioned as an interesting alternative that uses financial theory on real options, based on calculations with the Black and Scholes formula or a Binomial tree (Westgaard, 2013).

1. Independent water values

A conceptual illustration independent water values is shown in Figure 4, with three possible future reservoir fillings in the coupling point between SHOP and seasonal model. In each of these coupling points (red dots) a water value is calculated based on an average of three different inflow scenarios with respective end-reservoir levels in the seasonal model. These reservoir levels are given by volume coupling with the EMPS. Note that the example depicted in Figure 4 is a principle illustration, and in reality this is normally done for 80 different inflow scenarios as stated in Section 3.1 regarding the Seasonal model.

As indicated in Figure 4 the water value is dependent on a future reservoir filling at the end of the SHOP period, and thereby independent of any changes during the time interval of the SHOP optimization. E.g., for small-/medium sized reservoirs that are able to use, or store, amounts of water that can affect the reservoir level significantly during the ST optimization period, may be misguided by this valuation method. A typical scenario when this could happen is during large deviations from the initial inflow forecasts, thus resulting in risk of spillage or emptying the reservoir throughout the SHOP period.

Large reservoirs with a high degree of regulation is however not that affected by major deviations from the market environment in the LT model, i.e. large variations in inflow has minor effect on the end-reservoir levels during the ST optimization period.

The advantages with this method is that it can be easily interpreted by the production planner. It is especially well suited for periods with minor inflow, and large reservoirs with a high degree of regulation and low possibility for bottlenecks downstream.

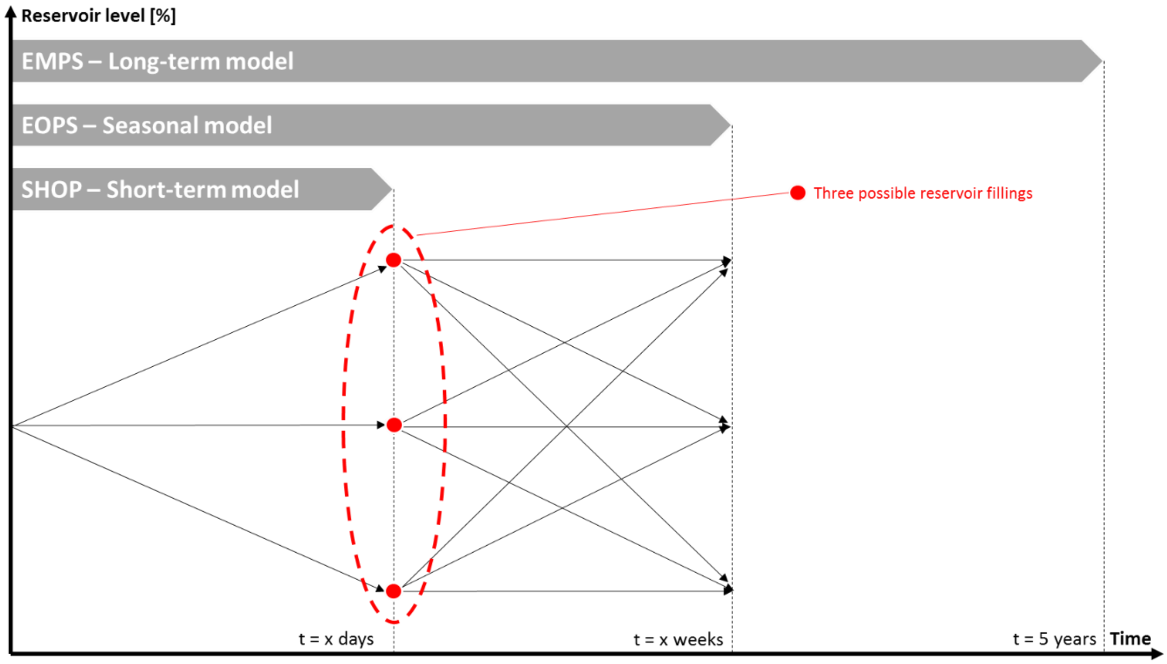

Figure 4 - Principle coupling of independent water values between the seasonal model and SHOP

2. Independent water value function

The second valuation method is almost calculated the same way as the independent water values but instead of estimating an average value, a function is generated that covers all reservoir levels between the red dots in Figure 4. This function is presented as a decreasing water value with respect to actual increasing reservoir level, referred to the end of the SHOP-optimization period.

A challenge with this method is that the water value is not necessarily only dependent on the respective reservoir level. In some river systems, reservoirs may even have short-term increasing water value due to increased water level, and the derived water value function will then be invalid (due to its decreasing profile). This can occur in a river system with multiple reservoirs that has the flexibility to balance water within the system, making it possible that one reservoir can have increasing water level even if the total water level in the system decrease, hence the value of the water increase. This example does also demonstrate the importance of valuating the flexibility within a system, which is discussed in the third method.

The independent water value function is therefore only valid for river systems with one reservoir, or one dominating reservoir among smaller reservoirs, since it is generated from the seasonal model, thus sensitive for short-term effects during the SHOP-optimization period. It is especially well suited for smaller reservoirs with a wide range of possible end-reservoir levels, meaning that it will probably give a more accurate water value than the first method.

3. Dependent water values (cut sets)

The third method, water value cuts, is illustrated in Figure 5. The left graph is presented with expected income on the vertical axis and reservoir level along the horizontal axis. The expected future income increases as the respective end-reservoir level (last time step in the SHOP period) increase, but the marginal value decreases which is illustrated with linear lines market as μ_1, μ_2 and μ_3. These linear lines (marked with blue), or cuts (Equation 3.3.1), represents different combinations of start reservoir levels in the seasonal model, and together the cuts are forming a function for expected income with respect to the reservoir level (the red graph). SHOP can use these marginal values as water values, reflecting the expected future income.

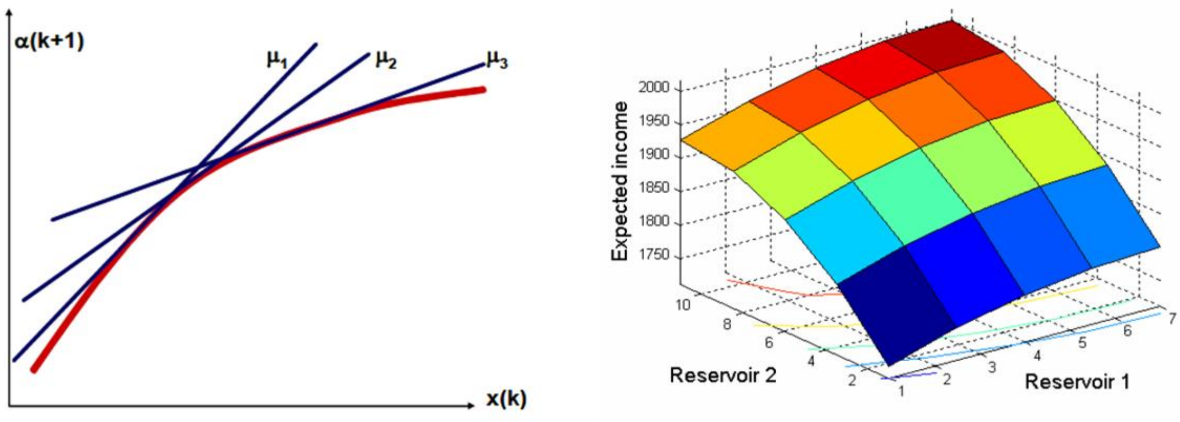

Figure 5 – Expected income function for one reservoir described by three cuts (left figure) and linearized profit function for two reservoirs described with 16 cuts (right figure). (Doorman/Fosso, 2013)

The right graph in Figure 5 is an extension of the previously mentioned cut sets but now as a function of multiple (two) reservoirs. The cut sets can therefore contain useful information about the water value depending on both its respective reservoir, and the other reservoirs in within the river system. A system with three reservoirs will result in four dimensions, and so on, for several reservoirs. The more cuts, the more precise expected income function (today 7 cuts is default in Seasonal model). The cuts are added to the short-term optimization problem as restrictions (Equation 3.3.3).

Pros:

- Mathematical correct way to describe a future water value – depending on multiple reservoir fillings and future opportunities.

Cons:

- Complicated water value description, hence difficult for production planners to visualise.
- Manual corrections in the short-term scheduling may become tricky.

Comparison

Summarizing the three water value methods, the first is the most practically to use and easy to interpret. It is well suited for medium/large reservoirs with a high degree of regulation, especially during periods with low inflow. The second method derives a function where the water value is decreasing with respect to increasing reservoir level, and it is more suited for smaller reservoirs than the first method due to its end-reservoir flexibility. However, it is only strictly valid for simple river systems consisting of one reservoir, or flexible systems with low probability for bottlenecks and forced generation. The third method is the optimal, and mathematically correct, method due to its ability to value flexibility within a system consisting of multiple reservoirs.

Statkraft has adapted SHOP to the first method, and further work done in this report is based on that valuation method as long as nothing else is specified. Note that since it is a future water value, it is kept constant during the whole optimization period (8 days) and factor-corrected if necessary (manual corrections done by the production planner) without the need of running the LTM. Statkraft is also testing the use of cut (3. Method) these days, as well as combinations of cuts and independent water values.

It is also worth mentioning that in addition to water values, SHOP is modelled with penalty functions that "activates" costs to the objective function if a reservoir runs in deficit or surplus with respect to stored amount of water. The penalty costs are so called strict optimization-restrictions. This form of optimization modelling makes it more likely that the short-term operation stays within the long-term strategy, in addition to satisfying other physical system descriptions.

3.3.2 The model structure

The deterministic optimization problem consists of an objective function (3.3.1) formulated as profit maximization in a deregulated market for N_{sh} hours into the future. The first part in the objective function is the short-term profits, and the second part, presented as α, is the expected future income. In the short term there is a lot of constraints attached to the optimization problem, but in a general matter it could be subjected to reservoir balances (3.3.2) and coupling with future expected income (3.3.3). The expected income yields for a number, N_m, of reservoir level combinations, *i*, at the end of the short-term scheduling period like illustrated in Figure 5.

Deterministic formulation

$$Max\left\{\sum_{t=1}^{N_{sh}} c_t^T x_t + \alpha\right\} \tag{3.3.1}$$

Subject to:

$$E_t x_{t-1} + A_t x_t \leq b_t \qquad \forall t \in [1, N_{sh}] \tag{3.3.2}$$

$$\alpha \leq \alpha^{*i} + \left(\mu^{*i}\right)^T (x_{N_{sh}} - x_{N_{sh}}^{*i}) \qquad \forall t \in [1, N_m] \tag{3.3.3}$$

$$x_t \geq 0 \tag{3.3.4}$$

c_t^T Income per produced unit

x_t Production at hour t

α Expected future income

E_t, A_t	Matrixes with the corresponding coefficients to the inequalities
b_t	Time dependent constants, e.g. inflow per hour
α^{*i}	Profits during the seasonal scheduling period for a given combination of start reservoirs, N_m. The combinations are known as a *cut*.
$x^{*i}_{N_{sh}}$	Given reservoir level at the start of the seasonal scheduling period (i.e. at the end of the short-term period) for reservoir level combination *i*.
μ^{*i}	= $\mu^{*i}_{N_{sh}}$, i.e. the index N_{sh} is dropped in the formulation of the short-term problem
N_{sh}	Number of reservoir level combinations at the start of the seasonal scheduling period that have been used. As discussed in relation to cuts, the more combinations, the more accurate approximation.

The optimization problem is solved by a five step strategy starting with an iteration process figuring out which units to use during different time intervals, followed by more detailed iterations given by the unit combinations with exact efficiency curves and production allocation within the system boundaries. All iterations are linearized with respect to the previous iteration. The last iteration establish an outline for the optimization method used in SHOP; mixed integer linear programming (MIP). The method is used for handling binary variables, for instance to define if a unit is running or not.

Stochastic formulation

A stochastic optimization problem accounts for the probability of a set of nodes, in each time step. The objective function presented in Equation 3.3.1 could in a general stochastic matter be formulated as Equation 3.3.5.

$$Max\left\{\sum_{t=1}^{N_{sh}}\left[\sum_{i\in I} p_i c_{t,i}^T x_{t,i} + \sum_{i\in I_{end}} p_i \alpha_i\right]\right\} \tag{3.3.5}$$

Where the node sets are indicated as *I*, and thus the node set for the end of the scheduling period as I_{end}. The probability of, for instance realizing the income $c_{t,i}^T$, is indicated as p_i. The stochastic problem formulation will not be discussed in this report, but it is relevant to mention the main difference between a deterministic- and a stochastic optimization model as the thesis address potential values of using a stochastic model when accounting for uncertainty in price, and/or inflow.

3.3.3 Topologies

Topologies of a river systems and principle plant elements, as respectively depicted to the left and right in Figure 6, is the fundament for the mathematical modelling of the optimization problem in SHOP. Topological couplings within the river system shows how the water can be managed in each reservoir with respect to inflow, spillage, bypass, and plant discharge. The time couplings within the scheduling period defines the water balance in each time step. Together, this results in a large number of equations for each reservoir in every time step during the scheduling period.

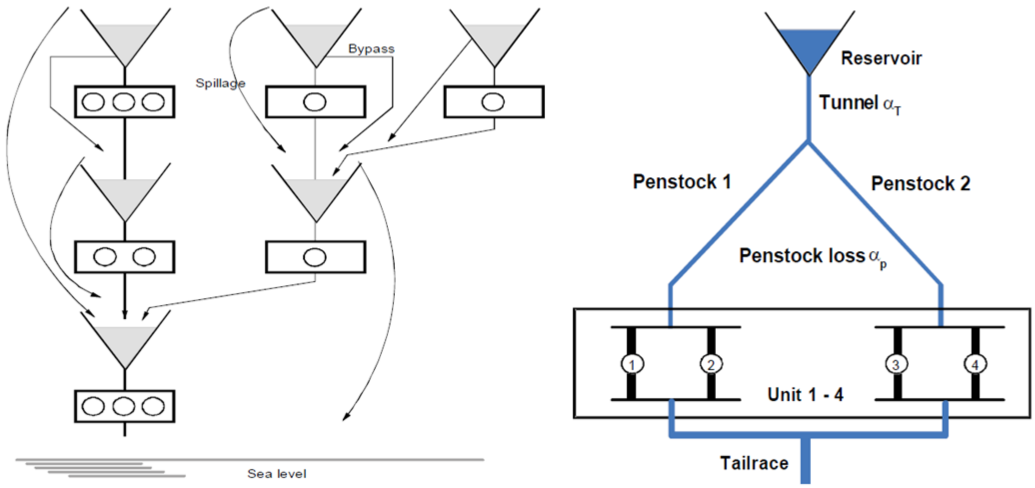

Figure 6 - Topologies of a river system (left) and principle plant elements (right). Source: Doorman, 2013.

As seen in the right part of Figure 6, reservoirs can be connected to the plants through multiple penstocks, with further connections to multiple generators. Friction occurs between the water and the walls in the tunnel, penstocks and tailrace. Hence head loss is also a variable that has to be included in the modelling. This can be a complicated task since the head loss is associated with static- and effective plant head (Doorman, 2013); in other words the discharge of water, which can be seen from Equation 3.5.4.

The relationship between discharge and production is non-linear and non-convex, depending on the number of units in operation. An illustration of this relationship is depicted in Figure 7, often referred to as PQ-curves, where the number of combined units are graphed in ascending order from left to right. It gets more complicated since the tunnel and tailrace loss is dependent on the discharge of all units, while the penstock loss is only dependent on the connected units discharge. PQ-curves is an important topic in the essence of short-term hydropower scheduling and a derivation of these relationships are presented in the next paragraph.

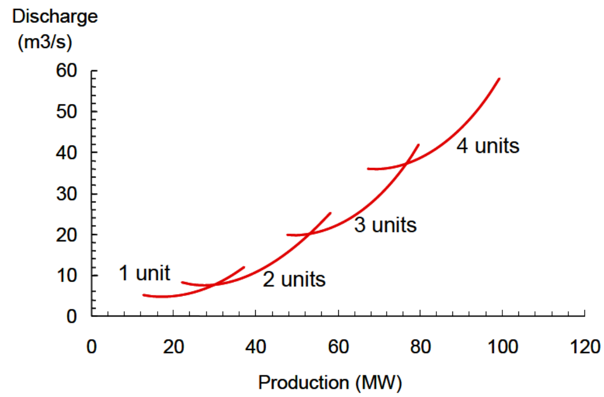

Figure 7 - Relationship between discharge and production with respect to number of generating units (Doorman, 2013)

3.3.4 PQ-curve

The PQ-curve is the relationship between electrical generation of power and physical discharge of water, as depicted for different unit combinations in Figure 7. It is an essential part of the STM, and for constructing the spot market bids in SPOTON. The PQ-curve is derived from calculations regarding head-loss and efficiency, giving the energy equivalent. A step-by-step derivation is presented, and it is based on course material from *TEP4100 – Fluid Mechanics* at NTNU (formula sheet, pipe head loss using Darcy friction factor). Starting with the head-loss-coefficient in the tunnels:

$$h_f = \frac{LV^2}{M^2 R_h^{4/3}} \tag{3.5.1}$$

Where:

h_f	Head-loss-coefficient	mVs
L	Tunnel length	m
V	Cross-sectional average velocity	m/s
M	Manning factor	
R_h	Hydraulic radius	m

The total efficiency (3.5.2) for an assumed water course is the product the product of the water-course, turbine, and electric generator:

$$\eta_{tot} = \eta_g \eta_t \eta_w \tag{3.5.2}$$

Where:

η_g	Generator efficiency
η_t	Turbine efficiency
η_w	Water course efficiency
η_{tot}	Total efficiency

The water course efficiency (3.5.3) has to be the effective plant head, $H - \Delta h$, divided by the gross plant head, H, due to the head loss caused by friction in the pipe(s).

$$\eta_w = \frac{H - \Delta h}{H} \tag{3.5.3}$$

$$\Delta h = h_f Q^2 \tag{3.5.4}$$

Where:

Δh	Head loss	m
H	Plant head (gross)	m
Q	Water discharge volume per unit of time	m^3/s

This leads to the energy equivalent, e [KWh/m^3], which determines how much electrical energy that is stored in each m^3 of water in the reservoir. The main determinants are the plant head and its efficiency, where both are dependent of the discharge level:

$$e(Q) = \frac{1}{3.6 \cdot 10^6} \cdot \rho \cdot g \cdot H \cdot \eta_{tot} \tag{3.5.5}$$

The energy equivalent, e, is often calculated with respect to an average head value, H, and a so called best-point efficiency value of η_{tot}. Finally, given the energy equivalent and the discharge level for a unit, one can derive the production-discharge relationship (PQ-curve):

$$P(Q) = e(Q) \cdot Q \cdot \frac{3600}{1000} \tag{3.5.6}$$

Where we multiply with the latter fraction to get the effect, P, in MW. Note that the energy equivalent is dependent of plant head and efficiency, which both are dependent on the discharge. The PQ relationship becomes non-linear (ref. 3.5.4) like indicated by the curves in Figure 7.

3.3.5 Marginal Costs

Marginal costs (MC) for a unit or a reservoir is not the same as the water values discussed earlier, which was more like a future opportunity cost. The MC is determined in the presence of each time step, hence it is therefore more suitable for bidding in the spot market. SHOP calculates individual MC as partial derivatives of the objective function (3.3.1), or Lagrange multipliers for relevant restrictions. This is also known as dual variables in the theory regarding linear programming (Doorman, 2013). Anyway, the MC quantifies the economic costs of producing one more unit of energy, EUR/MWh, at a given time step and is therefore an important decision parameter in a competitive market.

To distinguish the difference between water values and marginal costs, an alternative way of calculating MC is introduced. Recall the first water value calculation method mentioned in Section 3.3.1. If the 80 deterministic inflow scenarios in the seasonal model were calculated with respect to today's reservoir level, and not a future level, then the resulting water value would be a good estimation of the reservoir's MC.

However, the best way to determine the marginal costs is to use SHOP. The advantage of using SHOP is that the model is coupled with the long-term energy management through future water values, and that it accounts for detailed system description over an hourly time resolution. Together this will reveal eventual short-term restrictions affecting the marginal cost. In case of any new price- or inflow forecasts, SHOP can easily be ran with this new information.

Later in the report the use of MC's as water values will be analyzed. This is expected to be a particularly interesting benchmark during the start of a tapping-, or filling-, season for a medium seized reservoir. For this purpose, the resulting MC will not account for any uncertainty in price, nor inflow, due to the fact that SHOP is a deterministic model. An example is provided below.

Example – Use of MC in a deterministic model:
Given a random river system and week, with no production and increasing reservoir levels due to inflow. A simulation of the seasonal model is executed, and it provides SHOP with updated water values to use throughout the week. One of the water values are based on the operational method, and one from a set of cuts (week 44). During the present week a new, and much dryer, inflow forecast is delivered from the meteorologists at November 6th. These new inputs are executed in the seasonal model giving a new set of cuts (week 45). The new MC costs from a SHOP optimization using week 45 cuts is naturally higher than the ones from week 44, since the reservoir level is going to be lower than higher due to less inflow. An illustration of this example is given in Figure 8.

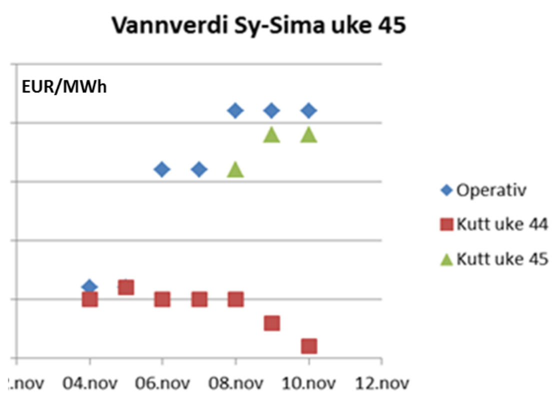

Figure 8 - Marginal costs based on operational water values (blue), cut sets (red), and cut sets after a dryer weather forecast (green). Source: Statkraft, 2014

The marks in the graph[5] represents the marginal costs calculated each day with SHOP during the operational week, with respect to:

1. The operational water values (blue), factor corrected for the new weather forecast
2. Cut set water values (red), calculated before the new weather forecast
3. Cut set water values (green), calculated after the new weather forecast

Observations above reveal that the cut sets only are valid for the market information used in the EMPS and seasonal model. Any significant changes in the market conditions like hydrological status, thermal

[5] Values are left out of the figure, due to sensitive information.

prices or availability/revisions should be accounted for, due to its potential effect on market expectations. A manual adjustment of the water values is therefore necessary, or new simulations of the models. The latter option is rather time consuming, hence the interest of investigating the use of MC from a multi-scenario optimization as water value(s).

A multi-scenario analysis in SHOP with respect to price and/or inflow will account for some unceratinty. An excepted MC time series can then be derived from the multi-scenario optimization, which again can give indications about the robustness of the future water value used in SHOP. This method is as mentioned earlier particularly interesting during seasonal couplings with relatively large variations in the reservoir levels.

3.3.6 Automatic Generation Control

Automatic generation control (AGC) can be evaluated with a smoothing-function (Norwegian: "Glattefunksjon") in SHOP. The production planners at Statkraft usually makes this adjustments manually before sending the production plan in to Statnett (the TSO). SHOP's smoothing function does this automatically for a chosen station, with respect to a magnitude given as user input.

The AGC can be view as average, hourly production values that are divided into different production blocks. The production blocks are defined by the user as; maximum deviation between the largest- and smallest value. If this limit is exceeded, a production block is established and the average value within it is calculated.

For example, after a optimization with SHOP the user gets an optimized production plan like the one illustrated by the dark blue diagram in Figure 9. If the user sets the AGC equal to 2, then SHOP will start at the first hour and iterate hourly throughout the period until it finds a scheduled plan deviating more than 2 from the maximum observed value, amounting to 10 in the first hour. The production block is then defined by the hours spanning between theses points in time, and the new values for the respective hours are the average value within each block.

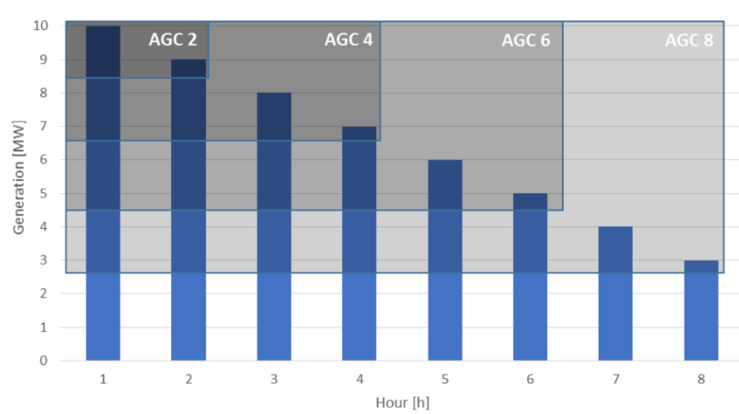

Figure 9 - Conceptual illustration of automatic generation control (AGC), and its defined "blocks"

Figure 10 show AGC results from a SHOP optimization. First, SHOP optimizes an original plan (light blue). Secondly, the user chooses AGC equal to 2, and a new production plan is generated (orange) with respect to the original. The same procedure is repeated for AGC equal to 5 and 10. All with respect to the original plan. One could also iterate with respect to the previous AGC plan, but this is not illustrated in this subsection.

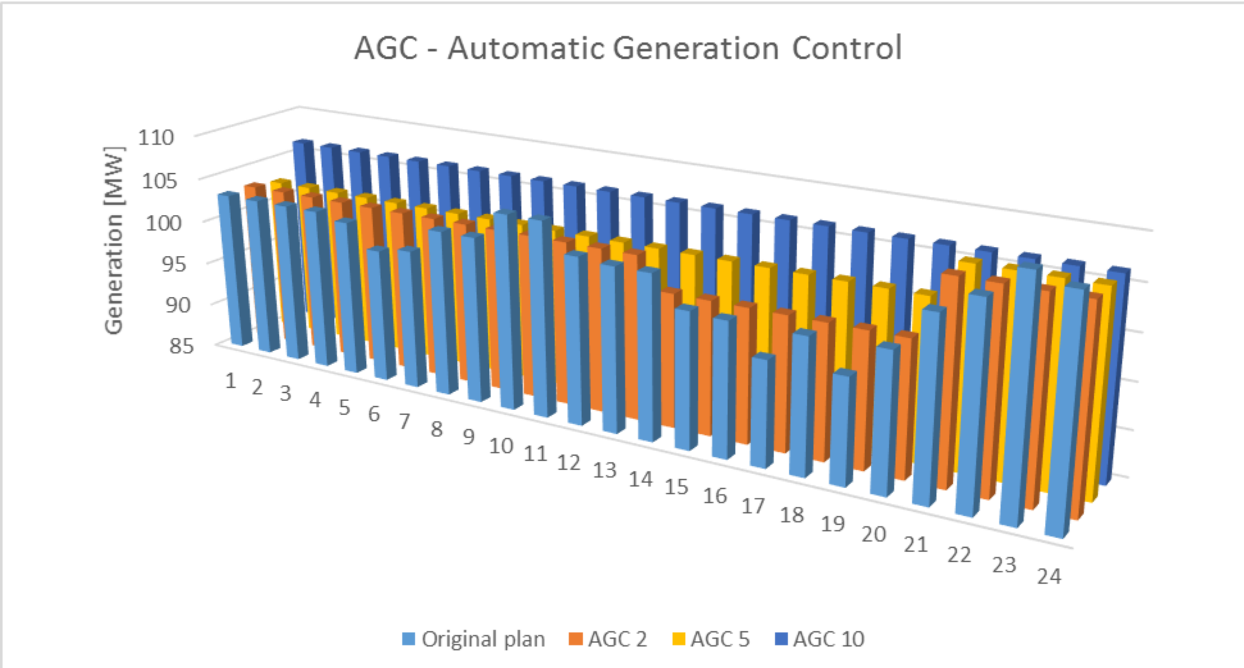

Figure 10 - SHOP optimizations with automatic generation control (AGC) equal to 0, 2, 5, and 10, over a period of 24 hours.

It is clear that the production plan from the original optimization varies the most from hour to hour. The AGC2 plan is a little smoother, where it uses the average value between the 1st and 13th hour of the day, for each hour, since the 14th hour deviates more than 2 from the reference value. Then the AC2 plan is set to the average value of the original plan between the 14th and 20th hour, where the 21st deviates more than 2 again. The third, and last, block for the AGC2 plan is during the hours 21 to 24.

3.4 Short-term Price- and Inflow Forecasts

Some of the calculations in this report will use short-term price forecasts, and it is therefore given an introduction in this section.

Price forecasts

The price forecasts are developed each work-day by internal, and external, analysts with hourly time resolution up to four weeks ahead. They use a fundamental model for the Nordic power market with important price drivers as input, while learning from recent spot prices are used to estimate unknown parameters in the model. This means that the forecasts are continuously benchmarked with the resulting spot price, and the model is calibrated with respect to these observations (Statkraft, 2013).

The price forecasts are used for several purposes like spot bids, production planning, water value calculations, maintenance planning, hedging and trading. It is updated three times each day due to new input data (see Figure 11). Some of the input data can be collected in real time, like consumption and nuclear output. Intermittent power production like wind production has to be estimated. The forecasted consumption is calculated based on temperature, and cloud cover. The urgent market messages (UMM) is used to keep track of transmission capacities, and availability of the supply side.

Inflow forecasts

Weather is the most significant driver for Nordic power prices (Statkraft, 2013), and can cause large variations in both supply and demand. Yearly hydropower energy production amounts to a market share about 50 %, thus its resources (water) is a considerable contributor shifts in the supply curve (Appendix I). For example, rainy periods fills the reservoirs with more water and the market supply side shifts to higher capacity at relatively low MC. This can result in a decrease in power prices, given that the demand for electricity is inelastic to price variations (Wangensteen, 2007).

The HBV (Hydrologiska Byråns Vattenbalansavdeling) model is used for reservoir inflow simulation and forecasting. It is a conceptual precipitation-runoff model which is used to simulate the runoff process in a given catchment area (Statkraft, 2013). The catchment area is a geographical area where all water, either it is above or under the ground, most likely will end up in the related reservoir. Combined with data about historical precipitation and air temperature, hydropower producers can simulate and forecast inflow to the water reservoirs. The model calculates snow accumulation, snow melt, actual evaporation, storage in soil moisture and groundwater, and runoff from the catchment.

Intraday inflow- and price relationship

The weather forecasts that are used to model inflow, production, and consumption is known as EC00 and EC12, short for European Centre for Model-range Weather forecasts delivered at 00 UTC and at 12 UTC. The forecasts are delivered twice a day, and the latest forecast available before sending the spot bids into the market is EC00. A time-line illustration is given in Figure 11. After the spot bids are sent into the market for clearing there are three new weather forecasts available before the end of the eventual spot bid commitments (EC12, EC00* and EC12*), referred to as intraday. The new weather forecasts gives new estimations about inflow, production, and consumption. Thus, potential deviations from the initial market outlook occurs (Markedskraft, 2014).

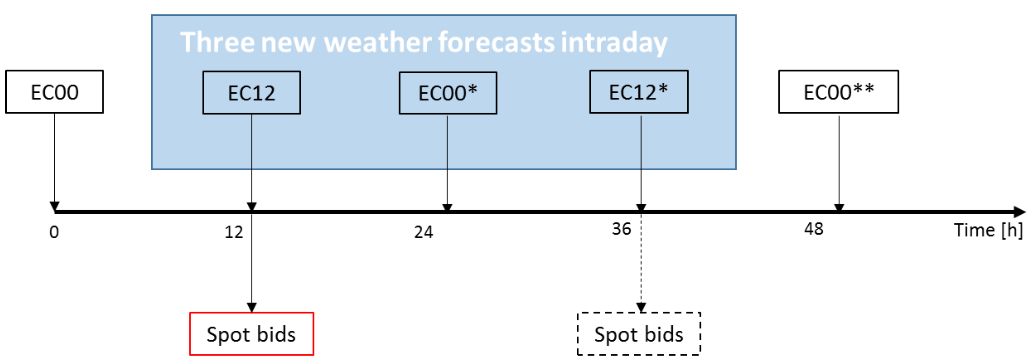

Figure 11 - Illustration of weather forecast deliveries and spot bids during a period of two days (48 hours).

New weather forecasts that affect intermittent power production like wind and solar, may contribute to larger price deviations than normal. The Nordic markets does not have a lot of solar capacity, but Germany has a considerable amount installed solar capacity. However, the scope with this example is to show that weather forecasts can have a significant impact on both day-ahead- and intraday prices.

4 METHODOLOGY

Investigating the economic potential of different bidding strategies, and exposed uncertainty for a hydropower producer requires at least one model of a river system. As for this thesis there were two possible ways to assess this task. The first pedagogic-friendly option was to model a real river system model, equal to one of Statkraft's, with an optimization program (e.g. GAMS; CPLEX), as well as modelling price forecasts derived by the statistical techniques like ARMA and GARCH (appendix I); taking historical prices, seasonal variations, spikes, and financial contracts into account (Florentina, 2013). The second real-case-advantage option was to use Statkraft's commercial optimization program SHOP which contains detailed, and highly accurate, models of both river systems and price areas. The latter option is pursued further in this study as a result of a tradeoff between learning outcome, experience, earlier research, time, and most importantly hands-on interpretation of the results.

The system models in SHOP (river systems, price areas) is rather complex and the program is not designed for applications being assessed in this thesis, hence some assumptions and adjustments had to be done to get the work done relatively efficient and less time consuming. First off is the ability to simulate multiple price scenarios at the same time, due to both the access to different price forecasts and the possibility to create bid matrixes (as one potential strategy). Secondly, it is desirable to lock the production plans to be able to simulate those one more time with respect to the spot price (ref. Figure 13) under equal system conditions, revealing eventually deviations in profits and thus the potential economic gain.

Figure 12 is presented to help the reader getting an overview of the main (functional) difference between the *commercial SHOP* and the *student SHOP*, as well as rest of the tool box used during this master thesis. The excel programs are developed both by the Student and Statkraft.

Commercial SHOP

- Limited use of price scenarios (3)
    - No production plan lock-function
- Real-time data input
- MIP-gap
- End reservoir restrictions

Student SHOP

- Expanded use of price scenarios (10)
    - Optimization wrt price
    - Lock production plans
    - Simulation wrt spot price (day-ahead)
- Historical, filtered data input
- MIP-gap adjustable with respect to hours into the period (save time)

Bid-Matrix Estimator

- Microsoft Excel macro programmed to calculate the bid-matrix sent to the day-ahead market
- Input: Price scenarios and the respective production plans (SHOP)
- Uses linearization- or stepwise technique to estimate the bid-matrix
- Calculate commited price dependent volume

Price Forecast Generator

- Microsoft Excel macro programmed to write desired price scenarios to be used in SHOP at a defined date and price area (192 hours time series)
- Input: Data and area
- Output: Frice forecasts (8) from database.

SHOP-Results Collector

- Microsoft Excel (VBA) program that collects desired results from SHOP after a optimization/simulation.
- Input: Dynamic workplace adress (results saved in .txt-format)
- Output: Revenue, market trade, startup costs, reservoir end value, minor penalty

Tableau & MS Excel

- Data analysis
- Data vizualization

Figure 12 – Overview and description of the "Tool box" used for this thesis (w.r.t. = with respect to)

Additional work-around simplifications are also given an introduction in Figure 12, namely *Price Forecast Generator* and *SHOP-results Collector* programmed in Microsoft Excel and VBA. Their purpose in association with SHOP is to simply create input price series and collect output results from SHOP, since this procedure is repeated several times and thereby expected to increase the time efficiency. All adjustments and simplifications regarding Student-SHOP are done in cooperation with Statkraft.

The excel-worksheets can be found in the Electronic Appendix.

4.1 Comparing decision parameters with SHOP

Most of the analyses presented in this report is based on day-ahead market bidding or scheduling. Different decision parameters are varied in the respective scenarios, and compared with each other to reveal their impact on the economic income from the optimizations. This thesis will mainly focus on the comparison of different price forecasts, and their income-effect with an optimization with respect to a reference; the spot price. The same method can be used to compare other decision parameters, for example inflow. Assumptions and simplifications that are discussed in this section will be tested and quantified in Section 5.

Each optimization in *Student SHOP* allows up to 10 different price scenarios, where the reference scenario usually is the spot price representing an optimal decision. An illustration of the procedure for comparison is depicted in Figure 13. It is important that the comparisons of the scenarios established for the simulation are consistent, hence deviations in the objective functions should only be a result of the day-ahead scheduling calculated by SHOP. Everything beyond the day-ahead time horizon is based on the same market conditions to provide realistic flexibility in case of any "bad" decisions made. Student SHOP does however not include any absolute end-reservoir levels due to its potential impact on penalty costs, especially at historical dates.

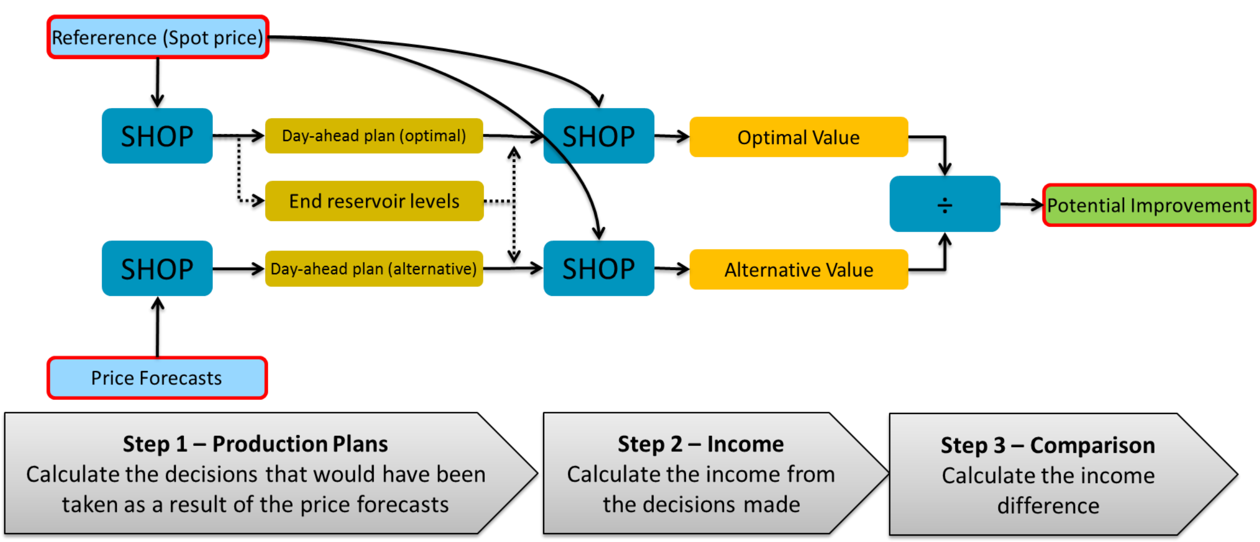

Figure 13 - The process of analyzing the potential economic gain of price forecasts used for price independent bidding with SHOP (Larsen T.J., 2013)

The first step, as illustrated in Figure 13, is to calculate optimal production plans with respect to the spot price (reference) and the price forecasts (best available information). The dilemma with this step is how to manage the water; a price series with higher values than the spot price will leave less water for the future, and vice versa for a price series with lower values than the spot. The time horizon in SHOP is eight days. Locking the end reservoir levels to be equal at the end of the following one day (day-ahead) would result in a too strict restriction allowing minimal flexibility, and unfortunate start-up costs of units in cases of major price shifts. Freezing the end reservoir levels at the end of the optimization period, after eight days, would give the optimization problem flexibility to catch up with the potential water imbalance. However, since the goal with the analyses in this thesis is to re-create realistic scenarios at a given historical dates, one should only use the best available information at that time and not cheat with any "crystal ball".

Figure 14 illustrates the first step (in Figure 13) with two price series; spot price and price forecast. The time frame on the horizontal axis is the following day (24 hours) representing the calculated day-ahead scheduling in SHOP. The price series are used to optimize respective production plans, where the black ones is a result of the spot price, and the green ones is a result of the price forecast. Note that this exemplification is analogue to price independent bidding, meaning that the producer send their bidding volumes regardless of what the clearing price becomes. The respective production plans, or volumes, are sent into the market and the income from these volumes (next day) are to be presented in the description of step two in the next paragraph.

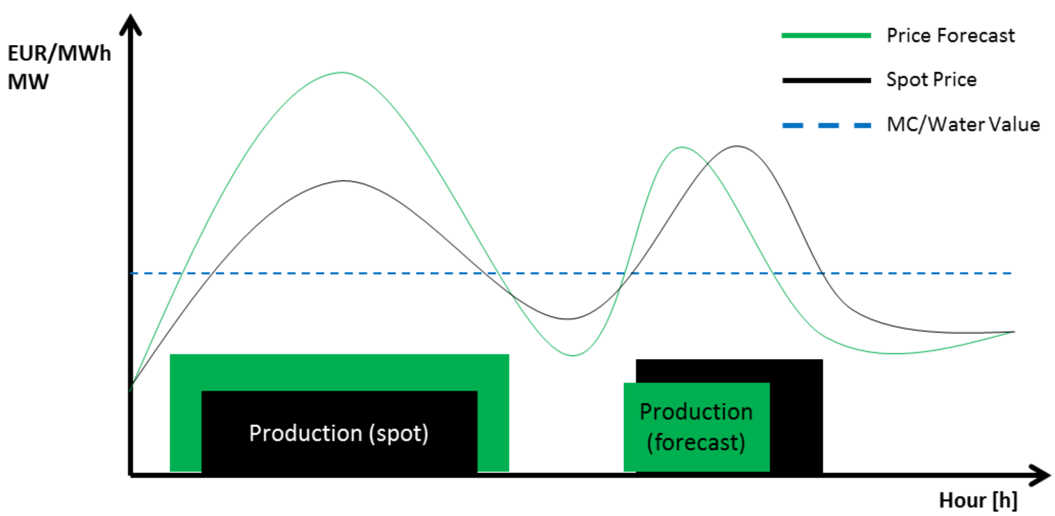

Figure 14 – Illustration of price independent volume bidding using a price forecast, and the cleared spot price for comparison (unknown when bidding)

Step two calculates the income from the decisions that has been made. Each scenario is now optimized one more time in SHOP but with respect to the spot price during the whole period, and with the day-ahead production plans from the previous optimization locked as "load commitments" (without market access). Everything beyond the day-ahead is left flexible, and the spot price will lead to approximately equal decisions for all of the scenarios, hence the income deviations are caused by day-ahead decisions.

Once again, there is a problem with the water management. Every scenario will most likely have different initial reservoir levels beyond the day-ahead plans, where everything was supposed to be consistent. It is however assumed small impacts on the income from this simplification, and while using independent water values, and relaxation of the end-reservoir restrictions, it may not have any impact at all.

The third step is simply a comparison of the income from the scenarios, revealing the potential economic gain for the respective price scenarios. The reference scenario, with the spot price, will naturally give the highest income since this is the optimal solution given the realized price in the day-ahead spot market. Subtracting the income from the other scenarios amounts to a value (in EUR) representing the maximum possible gain of improving the price forecast, in other words; the maximum potential economic gain of taking eventual price uncertainty into account in the SHOP-model.

The method presented is summarized below, with respect to price independent bidding as an illustration:

1. Optimizing production plans
    a. One reference plan (spot price)
    b. Several alternative plans (price forecasts)
2. Re-optimizing the production plans
    a. The day-ahead time steps (spot price): Scheduled plans are locked as load commitment
    b. Beyond day-ahead (spot price): Optimization of new scheduling
3. Comparison
    a. Measuring the income from the respective results in step 2.

In this report the comparison in step three will be tabled as income, market exchange, startup costs, end reservoir value, and minor penalty value. Hence, it is possible to get in-depth knowledge about the value of sold- and saved water, as well as exposing suspect results if the minor penalty restrictions provides income effects that are not consistent. The data is automatically collected after a optimization with the "Results collector" presented in Section 4.3.

The same method can be used to evaluate inflow uncertainty, or both price- and inflow uncertainty combined.

4.2 Establishing Price Forecast Scenarios

The price generator is a Microsoft Excel worksheet developed to search, and adapt, 8 price series to be used as scenarios for the method presented in Section 4.1. The objective with this is to be able to compare operative price forecasts, with respect to income from a river system or a price area. The price series are collected from one of Statkraft's databases through FAME (Forecast, Analytics, Modeling and Estimation). The output from this Excel-sheet presents eight different scenarios based on user input about date and price area. Among the scenarios we got; Spot price, initial- and final forecasts from *Analyst A*, final forecasts *Analyst B*, final forecasts *Analyst C,* and a naive series equal to the previous day's spot price. The naming Analyst A, B, and C is to stress that they are calculated from three different sources. Figure 15 depicts a graphical example of the output from the price generator, limited to the hours of the day-ahead bidding.

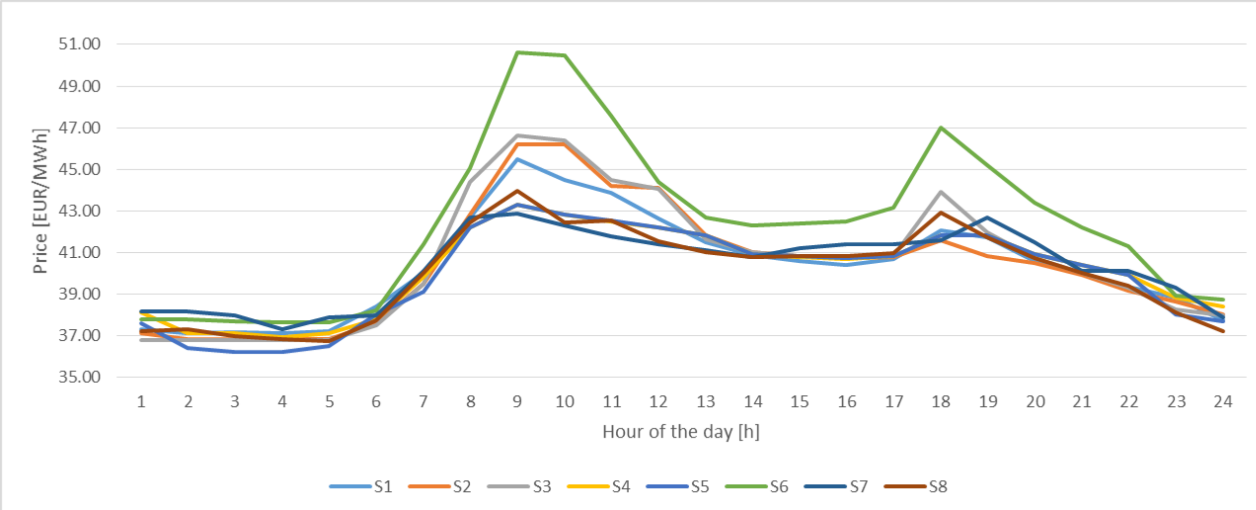

Figure 15 - Output example from the Price Generator (NO5 at Friday, February 15th 2013)

Table 1 shows a listing of the price scenarios in ascending order from scenario one to eight. Each scenario is noted with a sample date, where *t* represents the date when the bid-matrix is developed and sent into the market for clearing (hence the observed price for each forecast is noted with *t+1*). Each scenario is also attached to the respective analyst source.

Table 1 - Price scenarios provided by the price generator (derived by three analyst sources)

Price Scenario	Sampling date	Comment
S1	t+1	Next day spot (market)
S2	t	Initial model forecasts (analyst A)
S3	t	Initial forecast with adjustments (analyst A)
S4	t-2	Two workdays old forecast data (analyst A)
S5	t-2	Two workdays old forecast data (analyst A)
S6	t	Final forecast (analyst B)
S7	t	Final forecast (analyst C)
S8	t	Weekday: today's spot price (market) Weekend: same day previous weekend (market)

The program uses a look-up algorithm that checks the input date and makes sure that the specifications are fulfilled. For example if the input date is a Wednesday the price forecasts created that particular day are collected (S2, S3, S6, and S7), as well as the spot price that day (S8) and the 2 days old forecasts created at Monday (S4, S5) the same week, but time series starting at Thursday (the day-head bidding hours). Price forecasts are not made during the weekends, so the program collects the nearest, previous forecast (Friday) if that is a problem, e.g. if the input date is a Saturday or Sunday.

The two days old forecasts, and the naïve forecast, are not operative forecasts. The idea with the two days old forecasts is to see how they perform, compared with the updated forecasts. For example, what is the economic gain of calculating daily forecasts instead of every third day (Monday, Wednesday and Friday)?

The idea with the naïve forecast is to measure the utility of just using todays spot price as tomorrows forecast. The price profile during normal work-days is relatively similar, and the same yields for the weekends (ref. Section 6.5.2). Hence, a scenario where there are no updated price forecasts available, it might be useful to just use today's spot price. One could also use the naïve scenario as an alternative benchmark for the price forecasts.

4.3 Collecting the Results from SHOP

When SHOP is finished with an optimization, the results are saved in a text file in a dynamic folder (4.1) for a specific date, employee number, and application ID given by Windows OS:

\\shopts01\shop\Arbeid\yyyy.mm.dd\employee#_applicationID (4.1)

SHOP-Results Collector is programmed to read the text file containing results from each scenario at specific ID-numbers. The basic VBA-coding for this program is kindly developed by Arnstein Kvande at Statkraft, and further edited to fit the scope of this work by the Student. Since the text file is placed in a dynamic folder it has to be an input to the program, simply copied from SHOP's work location after an optimization. An execution button is added to the Excel program providing all the desired information. Table 2 is a random example of the output from the program, making it easy to copy the results and continue with other optimizations. The feature also eliminates the potential risk of reading and writing wrong numbers, if done manually by the user.

Table 2 - Example executed for Vik river system (NO5): Output from the SHOP-results Collector. Values are in EUR.

Scenario [EUR/MWh]	Objective value	Potential improvement	Sale	ΔSale	Startup costs	ΔStartup	Reservoir value	ΔReservoir	Penalty
S1	3 291 164	0	1 348 606	0	2 610	0	1 952 278	0	7 110
S2	3 291 096	68	1 348 490	-116	2 610	0	1 952 326	47	7 110
S3	3 291 131	33	1 348 594	-12	2 610	0	1 952 323	45	7 110
S4	3 290 652	513	1 348 069	-537	2 610	0	1 952 302	24	7 110
S5	3 290 788	376	1 348 204	-402	2 610	0	1 952 304	26	7 110
S6	3 290 987	177	1 348 744	-137	2 610	0	1 952 317	39	7 110
S7	3 290 971	193	1 348 406	-200	2 610	0	1 952 285	7	7 110
S8	3 290 933	232	1 348 362	-244	2 610	0	1 952 290	12	7 110

The potential improvement column in the table above is calculate as the income from Scenario 1 subtracted for Scenario X, where X is spanning from 2 to 8. Continuing to the right we got *ΔSale* representing Scenario X subtracted for Scenario 1. Last off, is the *ΔReservoir* amounting to the same procedure as the latter calculations.

4.4 Creating Price Dependent Bids with SHOP

This bid-matrix estimator is developed in connection with an earlier master thesis written in cooperation with Statkraft (Bakkevik, 2005). Some minor adjustments are done for this research. The objective with this program is to import resulting production plans from each scenario after a SHOP optimization, and together with the respective price series (per scenario) calculate a bid-matrix to be used for bidding in the day-ahead spot market, each hour of the day. There are many ways to organize the so called price dependent scenarios, e.g. variations in profile, moving average, percentiles or level, but this section will exemplify with fixed price deviations from a price forecast. This will cover the likely and potential clearing spot price. An example is depicted in Figure 16, including the resulting spot price in the day-ahead market (the black graph).

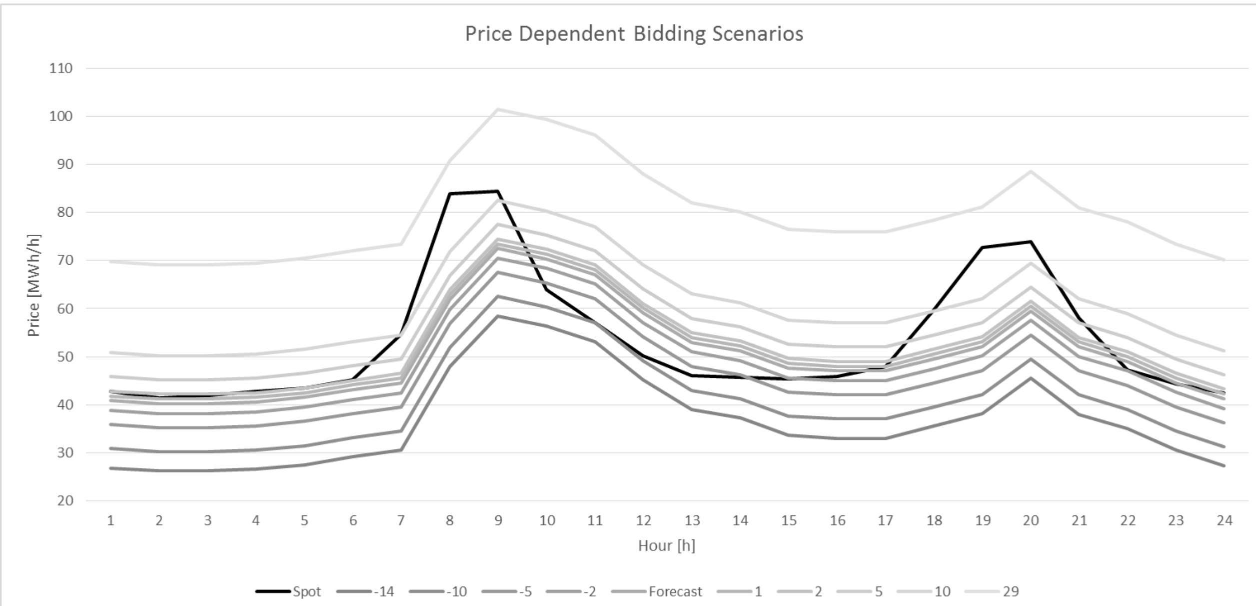

Figure 16 - Fixed price deviations from a price forecast. Used to construct price dependent bid-matrix.

One price forecast is used as a base point for constructing the price scenarios with small positive- and negative deviations close by its profile, and a few extreme deviations to cover extreme potential outcomes of the spot price. These price scenarios are used in SHOP to optimize respective production plans. The resulting production plans are then imported to the Bid-Matrix program. Table 3 shows an example of the resulting production plans for the first hour in each price scenario. Notice that scenario 1 – 10 is arranged by increasing price in ascending scenario order, hence the increasing production volume in Table 3.

Table 3 – Price [EUR/MWh] and resulting volumes [MWh/h] for each price scenario during the first hour

Scenario	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*
Price	26,81	30,81	35,81	38,81	40,81	41,81	42,81	45,81	50,81	69,81
Volume	35	124	329	1 309	1 756	1 840	2 100	2 369	2 396	2 421

The price-volume couplings in Table 3, for all (24) hours, are further processed with two optional methods for calculating the price dependent bids at different price levels: *linearization* or *step-wise* (Bakkevik, 2005). When delivering the bids to Nord Pool Spot one will need to present a matrix with columns representing particular price levels, and rows presenting the hour of the bid. The cells contains information about how many MWh the producer is willing to generate given a price and hour of the day. Since there is a limit for how many price levels you can include in your matrix (regulated by the market operator), one will need to decide which so-called break points to include. The break points are simply the chosen price levels in your bid-matrix. An example of these break-points are listed in the Table 4, spanning from 0 - 2000 EUR/MWh, but with highest density around the expected price interval 35 – 47 EUR/MWh.

Table 4 - Bids [MWh/h] for a given hour at increasing price levels (break-points) [EUR/MWh].

Price	*0*	***35***	*39*	*42*	*44*	*46*	*47*	*150*	*2000*
Linearization	35	**296**	1 352	1 889	2 207	2 370	2 376	2 421	2 421
Step-wise	35	**124**	1 309	1 840	2 100	2 369	2 369	2 421	2 421

Table 4 does also include the resulting volumes for the two methods during the first hour at the different break-points (price levels). As illustrated in Figure 17, the linearization method will always give higher volume commitments. For a given break-point, e.g. at 35 EUR, the two methods will give the following calculations:

Linearization:

The linearization method will interpolate the nearest scenarios in Table 3. The nearest scenarios is 124 MW and 329 MW for the respective prices 30.81 EUR/MWh and 35.81 EUR/MWh, giving 296 MW (Table 4) by interpolation.

$$124\ MW + \frac{35.00 - 30.81}{35.81 - 30.81}(329 - 124)\ MW = 296\ MW$$

Step-wise:

The step-wise method will always use nearest price with the lowest volume. As for 35 EUR, this will result in the volume coupled to 30.81 EUR/MWh at 124 MW.

$$Min\{Q(30.81\ EUR/MWh), Q(35.81\ EUR/MWh)\} = Min\{124\ MW, 329\ MW\} = 124\ MW$$

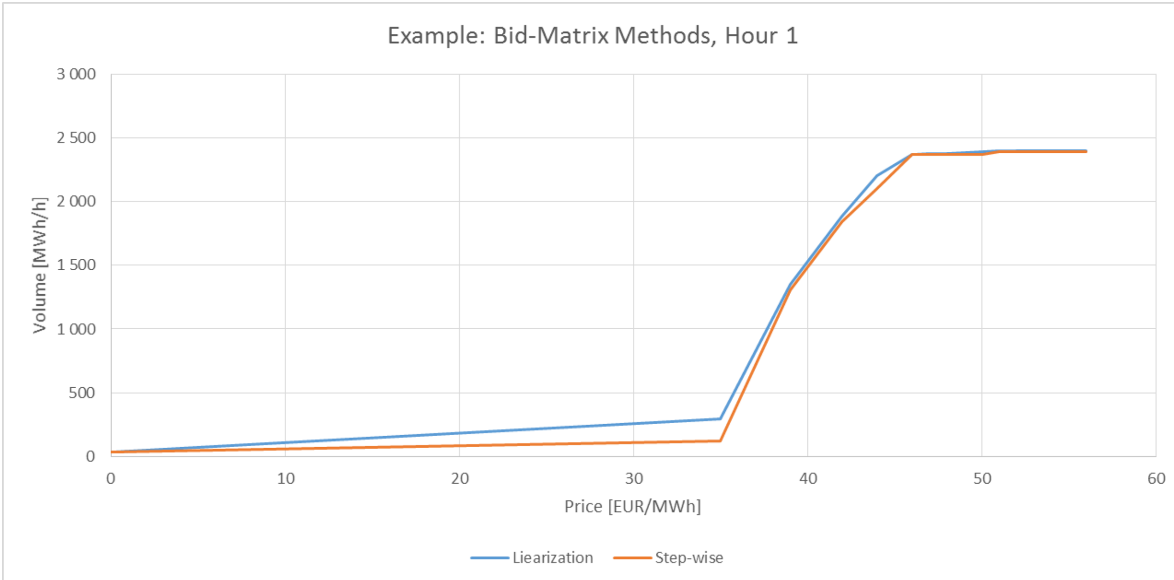

Figure 17 - Bid-matrix construction techniques: Linearization and step-wise volume-price couplings

Imagine that the price dependent bids depicted in Figure 17 are aggregated for each hour into a third axis, resulting in a three dimensional plot like the one in Figure 18. The resulting 3D plot represents a graphical presentation of the bid-matrix. The horizontal-plane consists of time and price (into the paper). The vertical axis is the amount (MWh/h) that the participant is willing to produce given a specific price (EUR/MWh) and hour of the day (h). The figure reflects to some extent the peak hours of the day, and increased volume with the increasing price into the paper, which is logic.

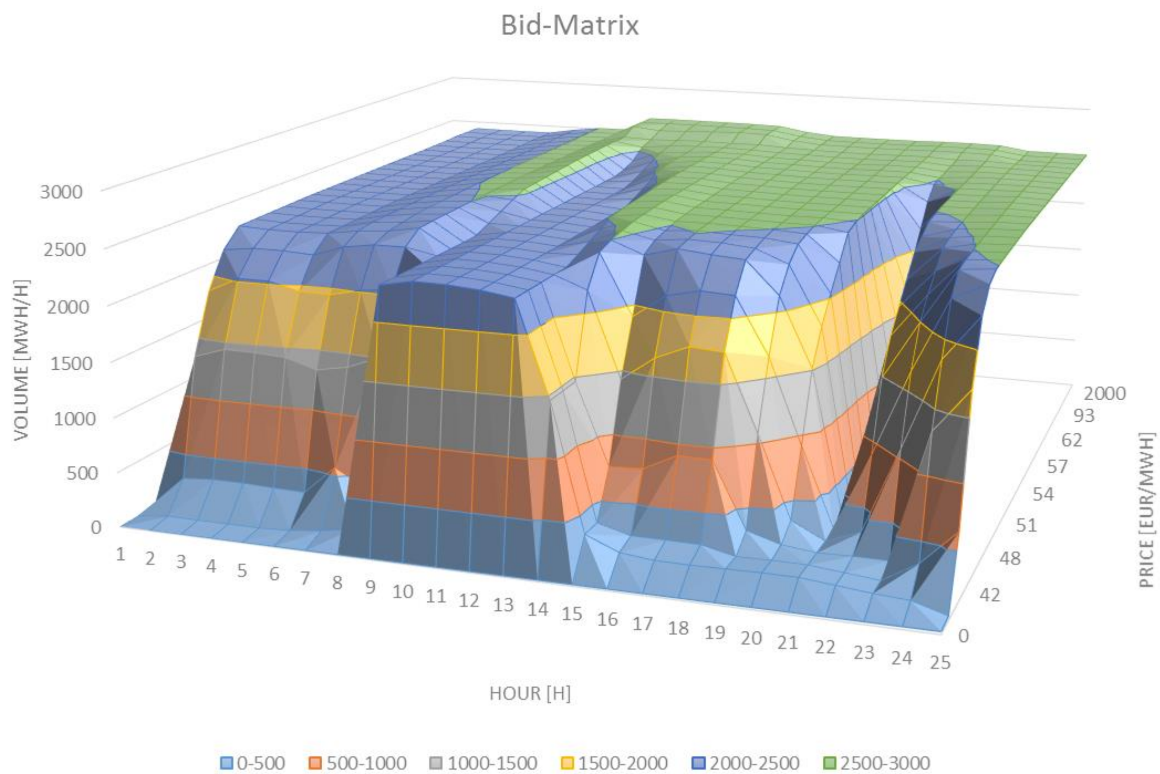

Figure 18 - Graphical presentation of a bid-Matrix calculated by the "bid-matrix excel program".

The committed volume after the market clearing is then calculated by interpolating the cells nearest to the cleared spot price (Nord Pool, 2014). The cleared spot price in the example above is 42.8 EUR/MWh for the first hour. Depending on which method used for calculating the bid-matrix (linear/step), the committed volume will become the result of an interpolation between the volumes at the breaking points 42 EUR/MWh and 44 EUR/MWh. The outcome for the first hour given for both methods in the Table 5.

Table 5 - Volume commitments after the spot price is cleared at 42.8 EUR/MWh for hour 1.

Spot	***42,8***
Linear Commitment	2 016
Step-wise Commitment	1 944

Summing up, the bid-matrix program helps the user to calculate price dependent bids based on results from SHOP. When the bid-matrix is calculated, the program will determine the committed volumes with respect to the cleared spot price. This allows us to compare a price dependent bids created with multi-scenario SHOP optimizations (from bid-matrix program) with operational price dependent bids (from SPOTON), and a price independent bid with respect to the spot price (SHOP). The price independent bid represents the optimal bid, thus the benchmark for other bidding strategies.

5 METHODOLOGY TESTING & APPLICATIONS

This section is an introduction for the analysis being presented later in the report. The aim is to test the methodology constancy with the adapted SHOP version; *Student SHOP*. Followed by a relative comparison of both income, and improvement potential for all the river systems in SHOP. Finally, an illustration of some basic optimizations to get an impression of what values that are being pursued in this research.

5.1 RELIABILITY OF *STUDENT SHOP*

Optimizations of a simple river system is presented in this subsection to confirm the reliability for the method used for the adapted *student SHOP*, hereby referred to as SHOP. For this purpose, Leirdøla river system in NO5 is used as an example. A presentation of the river system can be found in Section 3.5.

Four examples of the already mentioned challenges with Leirdøla is presented in the following paragraphs. The method described in Section 4.1 is put in context with the examples. The main objective is to confirm a consistent multi-scenario optimization, with the possibility for a comparison of the income effect from the price-series used in each scenario. Orally speaking; *"how many EUR can we potentially gain if the price series could be improved to match the spot price?"*. The examples are arranged as follows:

- Example 1: Flood season, winter to summer
- Example 2: End of flood season, nearly empty reservoirs
- Example 3: Inflow season, summer to winter
- Example 4: End of inflow season, nearly full reservoirs

Note that the price scenarios used in the following examples only are simple deviations from the spot price. This is to keep it simple, and to stress that is the price scenarios (analogue to price forecasts) impact on income we are interested in. The benchmark that is used for this purpose is price independent bidding, and this is not a common bidding strategy, but it is a good benchmark as it as it reveals the maximum improvement potential in a deterministic model. A price dependent benchmark would most likely benefit from the flexibility of the bids.

Example 1: Seasonal coupling winter to summer (27. March)

At 27th of March the reservoir at Leirdøla is nearly empty to be able to store the forecasted inflow. The water value at this particular date is 60 EUR/MWh. The spot price during the next 216 hours is relatively volatile, and varies between 47 EUR/MWh and 109 EUR/MWh. The time series are illustrated in Figure 19 where the black graph is the spot price, and the red lines is the mentioned water value and a manipulated water value equal to the average spot price during the next day. Remaining graphs are constant price deviations from the spot price.

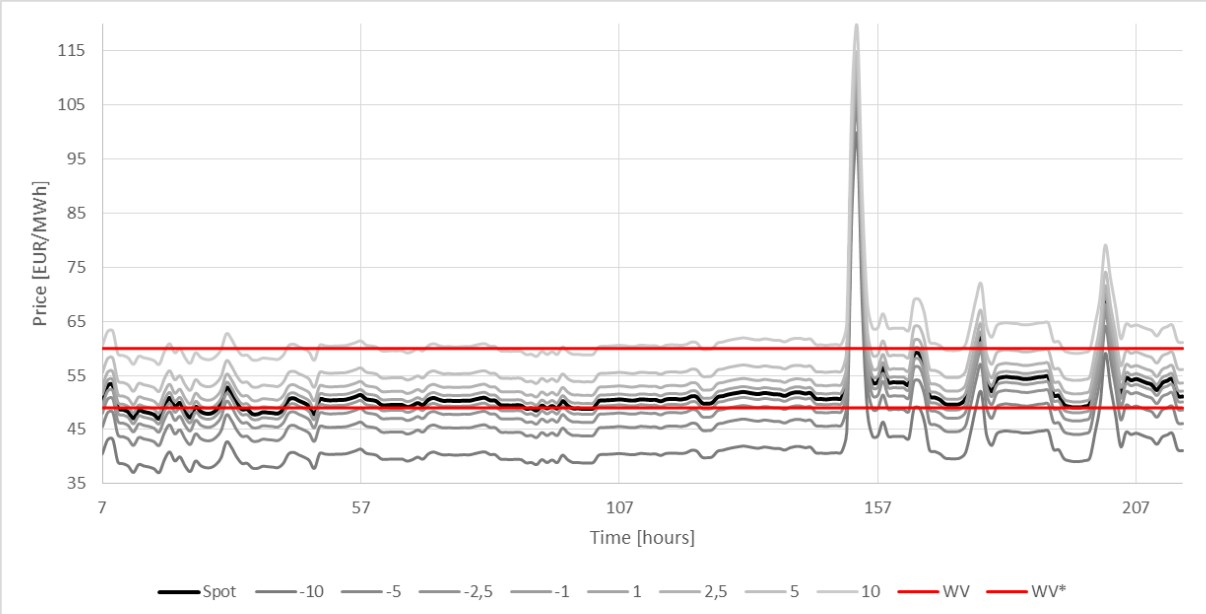

Figure 19 - Price series and water values used for simulating the seasonal coupling example at Leirdøla river system.

An optimization with SHOP gives the following results listed in Table 6:

Table 6 - Initial optimization results for the seasonal coupling 27th March at Leirdøla. Values are given in EUR.

Scenario [EUR/MWh]	Income	Sale	Startup costs	Reservoir value	Penalty
Spot price	96 505	47 843	980	49 642	0
-10	92 260	29 785	490	62 965	0
-5	94 031	31 936	490	62 586	0
-2,5	95 091	45 567	980	50 504	0
-1	95 936	47 226	980	49 690	0
1	97 095	54 275	980	43 800	0
2,5	98 165	73 701	1 470	25 933	0
5	101 149	102 385	1 960	724	0
10	108 034	109 270	1 960	724	0

Recall that the optimization results given in Table 6 is the same as *step one* in the methodology illustrated in Figure 13, meaning that scenarios are optimized independent of each other. All values, except for the price scenarios, are given in the European currency, EUR.

The price series that are lower than the spot price results in less income from sales and more water in the reservoirs, than the price series that are higher than the spot price. The value of the water left in the reservoir is calculated based on the water value multiplied with the remaining water. While the revenues from the water sold is calculated with respect to the corresponding price level for each hour multiplied with the volume sold. Hence, the total income is naturally not the same for all of the scenarios. The method described in Section 4.1 is designed to compare the scenarios, which as mentioned earlier is one of the main functionalities with *Student SHOP*.

The comparison strategy is scoped at bidding in the day-ahead market, thus only the production plans for the following day (28. March) are compared with a reference value for a stochastic price variable, in this case the spot price. The plans are locked, and optimized one more time with respect to the same reference. Everything else, beyond the next day, is left flexible with an equal system- and market environment. Hence, any deviations in the income is a result of mismatched water management for the next day. The comparison gives the following results presented in Table 7, which represents *step two* in Figure 13 (the methodology).

Table 7 - Comparison optimization results for the seasonal coupling 27th March at Leirdøla

Scenario [EUR/MWh]	Income	Potential improvement	Sale	Startup costs	Reservoir value	Penalty
Spot price	96 505	0	47 843	980	49 642	0
-10	96 505	0	47 843	980	49 642	0
-5	96 505	0	47 843	980	49 642	0
-2,5	96 505	0	47 843	980	49 642	0
-1	96 505	0	47 843	980	49 642	0
1	96 505	0	47 843	980	49 642	0
2,5	96 505	0	47 843	980	49 642	0
5	96 505	0	47 843	980	49 642	0
10	96 505	0	47 843	980	49 642	0

Note that only the +10 price scenario is above the water value for the mentioned time interval in the day-ahead market, which is only for two hours (Figure 19). This is not enough to compensate for start-up costs, and the water management during the next day is therefore equal for all the scenarios, hence no potential improvements as indicated in the table. The end reservoir value is identical for the scenarios, proving that every time step after the planning day is left with equal opportunities. This would not always yield for situations where the scenarios has different scheduling in the day-ahead market, which will be illustrated in the following examples. The results in Table 7 does also (so far) confirm that the comparison is consistent.

The water value was attempted to be lowered down to the average value of the spot price, 49 EUR/MWh, for the following day as indicated by the lower red line (WV*) in Figure 19. The sales were naturally higher for the initial optimization in SHOP, but scarce water resources resulted in that the sales never reached the price levels for the first day, thus no potential improvement in the comparison optimization. All of the available water was sold at higher prices later in the period, yielding for all of the scenarios. The results are not illustrated, due to no interesting findings and the illustration of the steps that already are given.

Example 2: Low reservoir level, nearly empty (17. April)

The results were almost the same as described in the previous example and paragraph, but without any production at all due to higher water value than the price series and limited amounts of water. The results from the initial optimization, and the comparison, was in line with the methodology. The results are not presented as they do not show any new findings.

Example 3: Inflow period filling the reservoir (24. July)

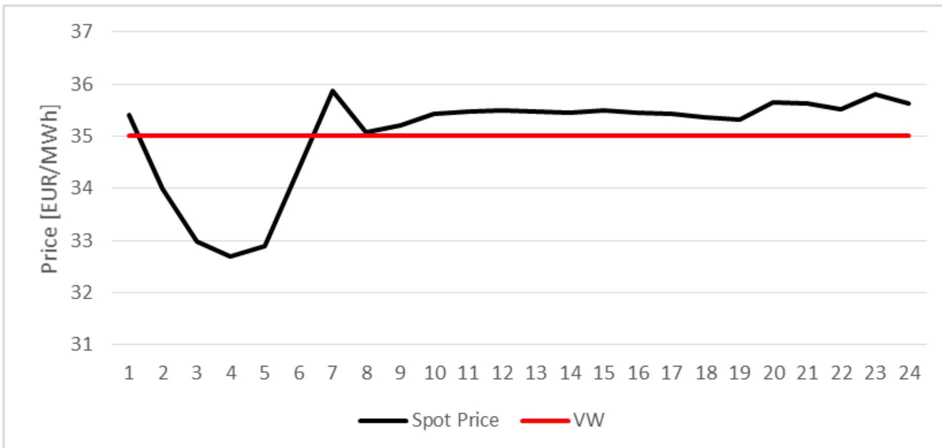

Figure 20 - Spot price and water value used at Leridøla 24th of July, 2013

This period is characterized by decreasing water value, due to inflow and increasing reservoir level. At this point of time the value amounts to 35 EUR/MWh. The water should be managed in such way that avoids spillage in the future. There is now enough water to be sold in the market during the whole period, and the price level the first day in the optimization is above the water value as shown in Figure 20, which indicates that there should be some potential improvements during the comparison. The initial optimization results are given in Table 8, below.

Table 8 - Initial optimization results for the inflow period 24th July at Leirdøla

Scenario [EUR/MWh]	Income [EUR]	Sale [EUR]	Startup costs [EUR]	Reservoir value [EUR]	Penalty [EUR]
Spot price	6 007 036	446 917	3 430	5 563 549	0
-10	6 003 150	58	0	6 003 208	0
-5	6 003 138	70	0	6 003 208	0
-2,5	6 003 132	76	0	6 003 208	0
-1	6 003 129	79	0	6 003 208	0
1	6 021 383	612 735	2 450	5 411 098	0
2,5	6 049 334	754 591	490	5 295 233	0
5	6 103 426	908 895	0	5 194 531	0
10	6 221 622	1 067 776	0	5 153 846	0

The comparative optimization with respect to the spot price amounts to the following results, in Table 9:

Table 9 - Comparative optimization results for the inflow period 24th July at Leirdøla

Scenario	Objective value	Potential improvement	Sale	Startup costs	Reservoir value	ΔReservoir	Penalty
Spot price	6 007 036	0	446 936	3 430	5 563 530	0	0
-10	6 006 593	443	375 555	2 940	5 633 978	70 448	0
-5	6 006 593	443	375 555	2 940	5 633 978	70 448	0
-2,5	6 006 593	443	375 555	2 940	5 633 978	70 448	0
-1	6 006 593	443	375 555	2 940	5 633 978	70 448	0
1	6 006 713	323	464 926	2 940	5 544 727	-18 803	0
2,5	6 006 430	606	470 865	2 940	5 538 505	-25 025	0
5	6 005 541	1 495	479 716	2 940	5 528 765	-34 765	0
10	6 004 899	2 137	483 342	2 940	5 524 497	-39 033	0

Due to unequal production plans (Table 10) for the following the day, the comparison resulted in potential improvements. The corresponding value is the income-effect of not using the reference value for the assumed stochastic price, which in this case is as simple as some given deviation from the spot price. Anyway, the improvement should be highest for the scenario deviating the most from the reference scenario. The following list shows the total generation according to the production plan given for each scenario.

Table 10 – Scheduled production volume at Leirdøla station during 25th July

SCENARIO [EUR/MWH]	PRODUCTION [MWH]
SPOT PRICE	1923
-10	0
-5	0
-2,5	0
-1	0
1	2460
2,5	2631
5	2887
10	2994

Price scenario +10 EUR/MWh is scheduled for the highest production, and the same scenario is also the one with the highest potential improvement. Note that it is not necessarily only deviations in the price profile that impacts the income effect, it is the "wrong" decisions that are made based on the price scenario. This is consistent with the methodology, as well as the results given by the comparison.

End-reservoir restrictions

Delta reservoir is included in Table 9 to pinpoint one of the factors discussed in Section 4.1 about the importance of equal end-reservoir limits for all scenarios. The conclusion was that there should not be equal end-reservoir requirements due to the fact that there are no "crystal ball" in a real case bidding scenario, which also should yield when analyzing historical real case scenarios. However, a comparison optimization with equal end-reservoirs is executed, and the results are presented in the Table 11.

Table 11 - Comparison optimization results with equal end-reservoir limits

Scenario	Objective value	Potential improvement	Sale	Startup costs	Reservoir value	ΔReservoir	Penalty
Spot price	6 006 268	0	265 093	1 960	5 743 136	0	0
-10	6 006 143	126	262 444	1 960	5 745 659	2 523	0
-5	6 006 143	126	262 444	1 960	5 745 659	2 523	0
-2,5	6 006 143	126	262 444	1 960	5 745 659	2 523	0
-1	6 006 143	126	262 444	1 960	5 745 659	2 523	0
1	6 005 766	503	265 287	1 470	5 741 949	-1 187	0
2,5	6 005 439	830	267 352	1 470	5 739 557	-3 578	0
5	6 004 369	1 900	262 282	1 470	5 743 557	422	0
10	6 003 713	2 555	262 319	1 470	5 742 864	-272	0

Some decimal slack in the end-reservoir restriction were necessary for successfully running SHOP, hence the minor deviations in reservoir value. The most interesting observation is that the potential improvement increased for those scenarios who produced according to Table 10, and decreased for the scenarios who had zero production. The first can be argued with less flexibility to catch in the deficit produced volume, and the penalty for making a poor decision increase.

Limited MIP-flag

Another suitable test for this case is the MIP flag. As discussed in Section 4.1 does the SHOP-user have the opportunity to adjust the MIP flag for saving time on the SHOP calculations. The resulting comparison optimization with MIP flag activated for 60 hours is presented in Table 12. Usually, the MIP flag is active for all hours during the optimization period. Recall that the MIP gap can be viewed as an accepted deviation from the optimal solution, this MIP gap is chosen to be as low as possible for this kind of analysis where we want especially exact results. The MIP gap for the Leirdøla examples is equal to one.

Table 12 - Comparison optimization results with MIP-flag for 60 hours into the optimization (not full MIP-flag as earlier)

Scenario	Objective value	Potential improvement	Sale	Startup costs	Reservoir value	ΔReservoir	Penalty
Spot price	6 006 659	0	454 107	3 920	5 556 472	0	0
-10	6 006 220	439	382 762	3 430	5 626 888	70 415	0
-5	6 006 220	439	382 762	3 430	5 626 888	70 415	0
-2,5	6 006 220	439	382 762	3 430	5 626 888	70 415	0
-1	6 006 220	439	382 762	3 430	5 626 888	70 415	0
1	6 006 334	325	472 145	3 430	5 537 619	-18 853	0
2,5	6 006 046	613	478 120	3 430	5 531 356	-25 116	0
5	6 005 158	1 500	486 895	3 430	5 521 693	-34 779	0
10	6 004 520	2 139	490 532	3 430	5 517 418	-39 055	0

The results are almost identical with Table 9, which is the same optimization but with full MIP. The MIP flag covers the day-ahead SHOP environment, plus 18 extra hours, and it is therefore assumed that it would give the same results. However, there are some small deviations. It seems like the models allows more sales in the market, which also have included additional startup costs for the generating unit. These deviations are found in timer series beyond the chosen MIP flag period. Anyway, the ratios of potential improvements (compared with each other) seems to be about the same. For instance, potential improvement for scenario +1 amounts to 60 % of scenario +2.5 in Table 10. In Table 12, the same ratio is 53 %.

Example 4: Nearly full reservoir at the end of inflow period (16. October)

The reservoir is now filled with 80 % of its capacity, with a water value amounting to 31.70 EUR/MWh. The reservoir is managed in a way that saves water for the winter season as well as avoiding potential spillage. The spot price indicates that there will be small amounts of sales during the optimization period, especially during the following day when the average spot is lower than the water value. The initial optimization is as illustrated in Table 13, below.

Table 13 - Initial optimization results for Leirdøla in the end of the inflow period (16th October)

Scenario	Income	Sale	Startup costs	Reservoir value	ΔReservoir	Penalty
Spot price	7 153 408	-377 461	1 960	7 532 828	0	0
-10	7 277 317	-351 405	2 940	7 631 662	98 834	0
-5	7 214 484	-412 150	2 450	7 629 084	96 255	0
-2,5	7 183 250	-441 295	1 960	7 626 505	93 677	0
-1	7 164 593	-459 535	1 960	7 626 088	93 260	0
1	7 147 745	58 263	2 450	7 091 932	-440 896	0
2,5	7 154 244	244 275	490	6 910 458	-622 370	0
5	7 172 493	373 488	0	6 799 004	-733 824	0
10	7 221 942	497 731	0	6 724 211	-808 618	0

At first sight it might seem weird that SHOP choose to use more money on buying electricity from the market as the price increase for the lower price scenarios. The reason for this is that on 16th October there was a load obligation in the model, meaning that there were a given amount of load that had to be covered for the corresponding hours (75 MW in this case). SHOP decides to buy this load obligation from the market as long as the market price is lower (cheaper) than the water value. The water value is about the same as the average spot price in this example, hence SHOP starts to cover the obligation and sell power in the market for the first positive price scenario. An income comparison of the resulting scheduling plans is provided in Table 14.

Table 14 - Income comparison for Leirdøla in the end of the inflow period (16th October)

Scenario	Income	Potential improvement	Sale	Startup costs	Reservoir value	ΔReservoir	Penalty
Spot price	7 153 408	0	-377 461	1 960	7 532 829	0	0
-10	7 153 408	0	-377 461	1 960	7 532 829	0	0
-5	7 153 408	0	-377 461	1 960	7 532 829	0	0
-2,5	7 153 408	0	-377 461	1 960	7 532 829	0	0
-1	7 153 408	0	-377 461	1 960	7 532 829	0	0
1	7 152 324	1 084	310 280	2 450	7 465 054	-67 775	0
2,5	7 151 330	2 078	280 025	1 960	7 433 315	-99 514	0
5	7 150 409	2 999	270 259	1 960	7 422 628	-110 201	0
10	7 149 345	4 063	263 570	1 960	7 414 875	-117 954	0

For each price scenarios that has lower values than the water value, there is no potential improvement due to the same decision to cover the same amount of power from buying in the market. The costs of buying from the market were varying, but as long as the clearing spot price the following day does not indicate any production as well, the potential improvement will remain zero. Remember that it is the clearing spot price that yields for any purchases or sales, not the “forecasted” price. From Table 14 one can see that the turnover in the market now is the same for the negative price scenarios, when comparing the decisions with respect to the spot price.

5.2 River Systems in SHOP – Objective Values & Potential Improvements

A similar analysis like the one presented in Section 5.1.2, with price scenarios deviating from the spot price, are in this section optimized for all the river systems modelled in SHOP. The price deviations from the spot price are constant at +/- 1, 3, and 5 EUR/MWh for every hour in the optimization period, to reflect more or less the realistic price forecast's potential deviation. The objective is to give the reader an introduction to the river systems in SHOP, and the significance of (fictive) price forecasts in the respective river systems.

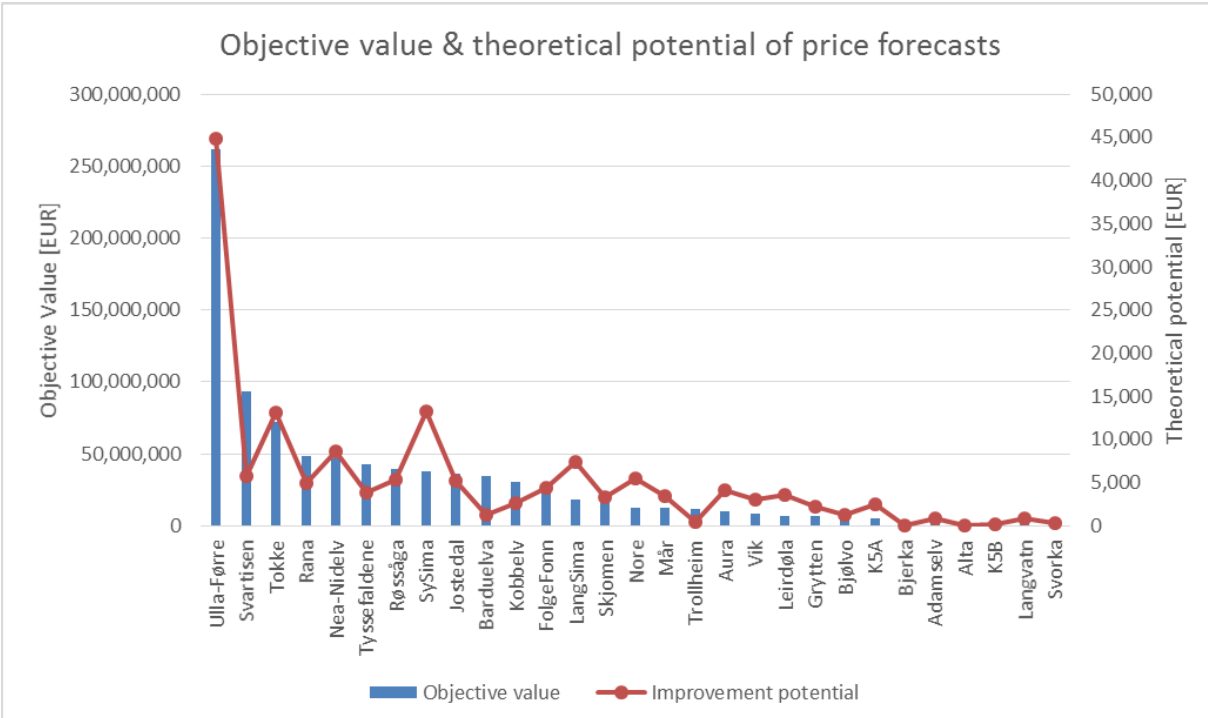

Figure 21 - Objective value and average (of 6 price scenarios), potential price-forecast-improvement for all river systems in SHOP. Day of optimization; 20th of February, 2013

Figure 21 shows the objective function (blue bars), and the theoretical potential improvement (red line) of the price series that are benchmarked with respect to the spot price. The potential improvement is an average value from the respective price series introduced above. Both values are presented for every river system, sorted in descending order with respect to the objective value. The objective value indicates the size of the river system. The potential improvements of a (fictive) price forecast is naturally dependent on the size of the system, which also is indicated by the figure to some extent. Note that the size in this context is the amount of water, but it is assumed that this value is more or less associated with the production capacity as well.

Each optimizations are executed at the same historical date, which in this case is 20th of February, 2013. Inputs like reservoir level and water values are uploaded for the respective date, and river systems. Note that the water value varies from system to system, thus no obvious pattern in the potential improvement for the deviating price scenarios. The water value could for example been set to an average value of the spot price, which would have resulted in a more consistent pattern since the units would either be generating, or not, when the price is above, or below, the water value. Due to various systems complexity, the conclusion was to reflect this and use historical water values. Hence the variation in the red graph, which is highly dependent on the water value.

Anyway, one could use this information to evaluate the theoretical value of potential improvements, relative to the total income (objective value). On average, this relation amounts to 0.019 % for the (six) price scenarios introduced.

Side-note to the relation above:
A more descriptive-, and accurate, relation is to measure the potential improvement with the value of sold energy in the day-ahead market for the spot price. E.g. if value of sold energy is zero, than the potential improvement would be 0 %, hence the price forecast is irrelevant for the day-ahead water management. Elsewise, if the there is a value of the quantity sold, it would amount to a percentage of the sold spot-volume. An example is provided where two "forecast-volumes" are indicated in Figure 22, and the arrows highlight the relative sizes.

Figure 22 - Conceptual illustration of sold energy quantities, used for describing theoretical improvement potential

5.3 Sensitivity Analysis – Feasible Improvement Potential

A sensitivity analysis is presented for the selected river systems in Section 7. The goal with this analysis is to show that there is always an upper-limit for how large the improvement potential of a price forecast can be, or how poor a price forecast can before it no longer has any effect on the decisions for production scheduling. For example, if a reference price is used to create price scenarios with increasing (or decreasing) price levels, one will at some point reach an upper limit for the theoretical improvement potential when there is no more capacity to produce more (or less) energy beyond that point. An illustration is given for Leirdøla river system in Figure 23.

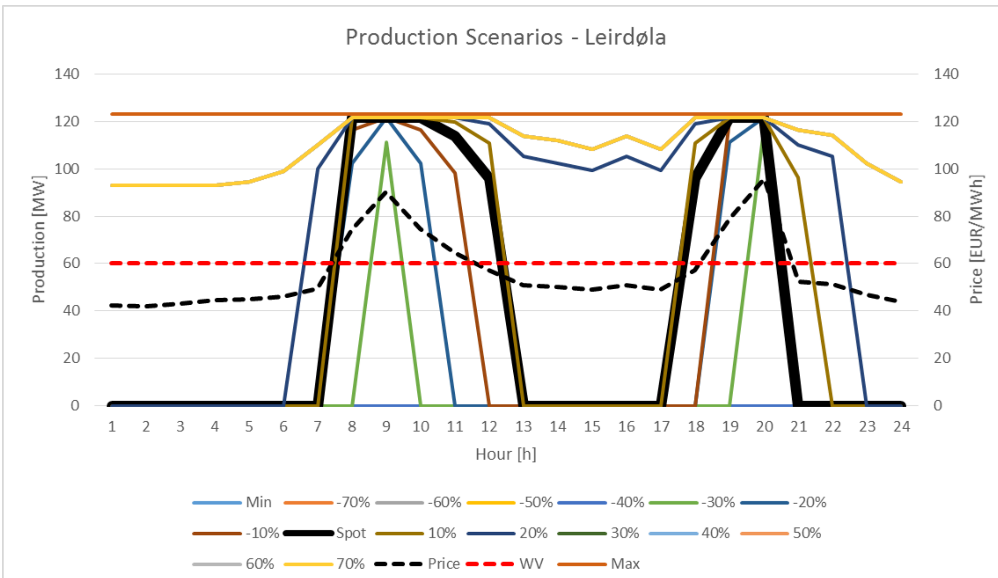

Figure 23 - Production-sensitivity analysis at Leirdøla w.r.t. to a reference price/plan (thich black) and deviating price scenarios (+/- 0% - max/min). WV = average reference price.

The reference price scenario schedules for the "spot"-production, marked with thick black colour in Figure 23. The rest of the graphs represents the scheduled production for their respective price scenarios, where the price scenarios deviates +/- 10%, 20%, 30%, 40%, 50%, 60%, 70%, as well as minimum price and maximum price. The min- and max price scenarios gives the lowest and highest production that is possible. The figure does also contain information about the reference price, marked with stippled black, as well as the water value marked with stippled red.

The theoretical improvement potential (defined in Figure 1) for Leirdøla is plotted into the blue line in Figure 24. The improvement is almost symmetric around the y-axis, due to the fact that the WV is calculated as an average value of the price reference. However, since it is an average value of 24 hours, it may still give minor deviations in the scheduled production due to e.g. start-costs, unfortunate production from 24 hours and beyond, or ramping. When the price deviation reaches a certain point around -40% and +30%, the potential improvement tangents, meaning that no matter how much poorer the price forecast gets, it will have no more influence on the income due to max- or min production capacity.

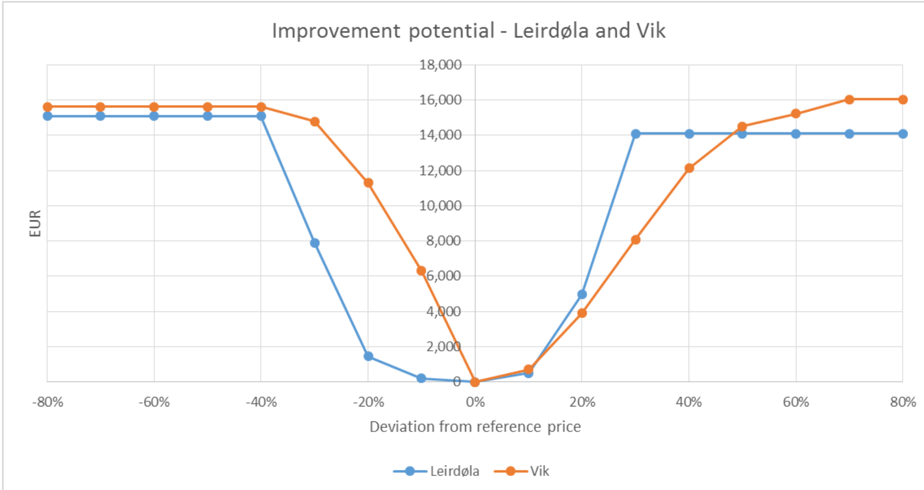

Figure 24 - Theoretical improvement potential with respect to price deviations from the reference price. Leirdøla (blue) and Vik (orange).

The same price series and water values are used at Røssåga river system, but only with positive price deviations. The maximum theoretical improvement potential at Røssåga is significantly larger, due to its larger production capacity. It tangents around 80% deviation from the reference price, amounting to a total improvement value of 100 000 EUR.

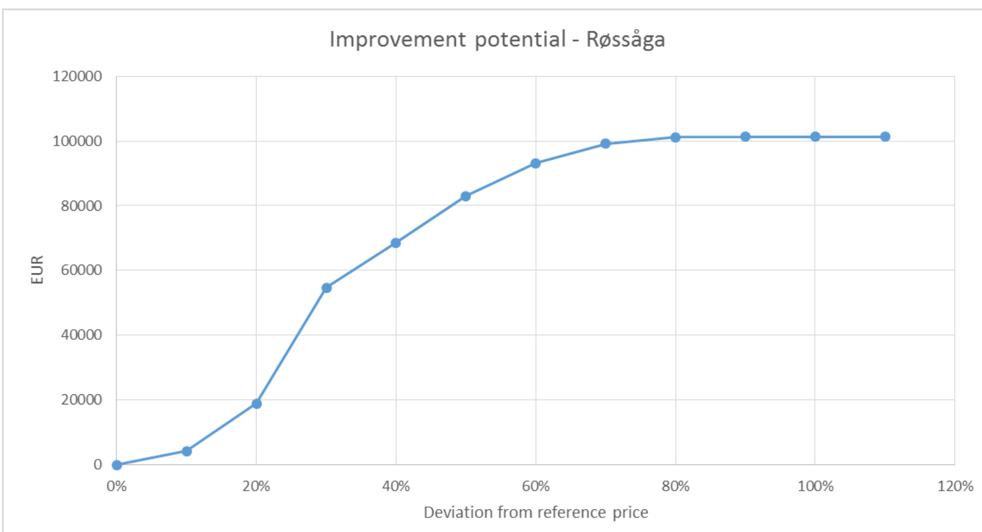

Figure 25 - Theoretical improvement potential with respect to price deviations from a reference price. Røssåga river system.

Note that the potential improvement varies with the market conditions, i.e. price level and water values. But the same observations about a tangent improvement value, like those presented in this section, will still be valid in other situations. The point is that this limit, with respect to an optimal reference, defines the feasible solution space for a stochastic value (e.g. price in this case). A real price forecast will of course not be as poor as this limit, and will most likely lay closer to the reference, than the limit.

5.4 The value of responding to uncertainty over a period of time

This section will present a fictive example which compares the potential value of daily establishments of day-ahead bids, with a one-time calculation of day-ahead bids for the same period of time.

- Period bid: 1 “extended day-ahead” bid for 9 days ahead, based on a price forecast
- Day bids: 9 day-ahead bids, based on latest available price forecast

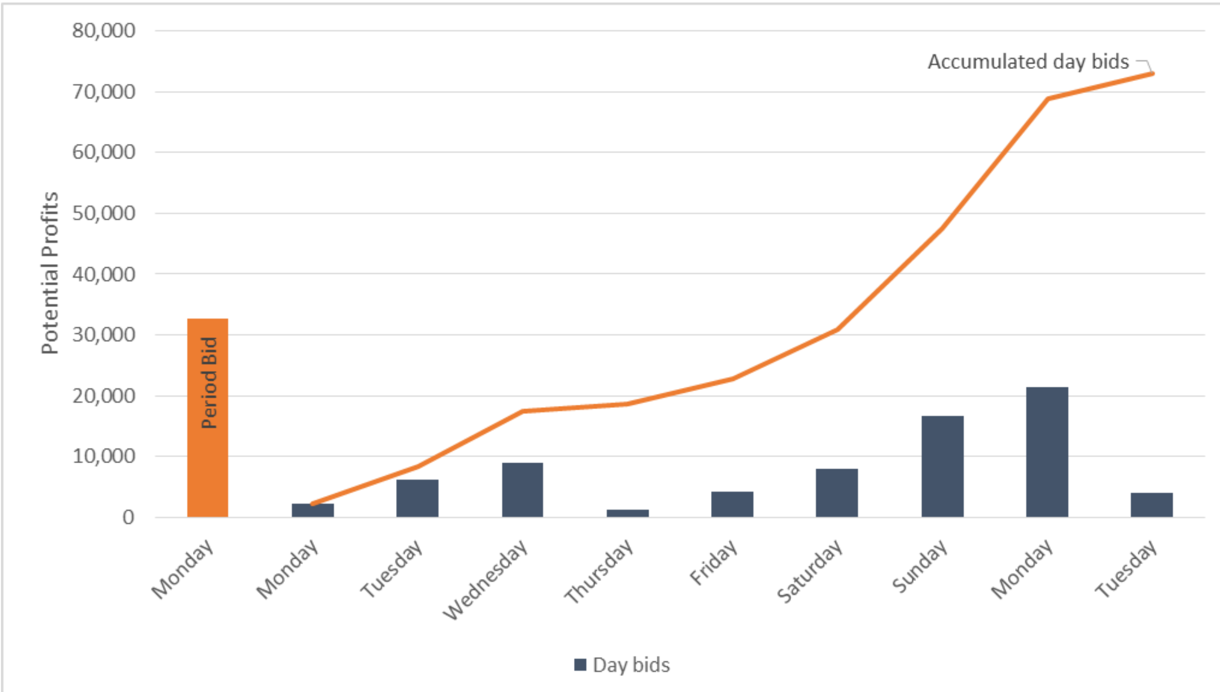

Figure 26 - Potential profits of bidding each day over a period VS one bid for the same period. SySima river system (NO5).

Let’s consider one river system, in this case SySima (NO5). A comparative setting where one price independent bid is created for a period of nine days in total, measured against normal day-ahead bids during the same period. The idea is that the producer totally relies on its initial bids, and use this plan to bid in the spot market each day during the period.

Figure 26 shows the potential improvement results from the SHOP optimizations under equal market conditions during the first week in February, 2013. The day-ahead bids are aggregated into a comparative graph (accumulated day bids) to show that the potential profits of bidding each day is greater than the potential profits of only bidding once, for the same period of time. In other words, it is worth using up-to-date price forecasts and create new bids with a shorter time horizon, frequently.

This is of course an unrealistic case, as no rational hydropower producer would choose to rely on price independent bids created for a longer period of time (nor price independent day-ahead bid at all, with a few exceptions). There were also some minor deviations in the end-reservoir levels, for the two scenarios, where the whole-period bid scheduled to sell more water due to a higher a price forecast on average. However, the case remain consistent since best available information about price uncertainty where used in each scenario, which was the main intention with this example.

The key explanatory factor for these results are uncertainty. There is no surprise that daily bidding is more profitable as the exposure to time-length and uncertainty is reduced. Real price forecasts and water values where used in this example, and it is interesting to note the increase in potential profits over the weekend, since the latest price forecast available was created at Friday, thus uncertainty about the spot price increase throughout the weekend.

5.5 Price forecasts accuracy in different price areas

The same method for price independent bidding as the previous examples can also be used to map price forecast accuracy. Recall Table 1 listing the available price forecasts used in this study, for this case numbered from one to seven, where number one is the spot price, and number seven is the final forecast calculated by Analyst C. Figure 27 shows the result of a sample amounting to totally 30 optimizations, divided into five price areas, and one optimization every second month starting in February. This breaks down to six optimizations per price area, which is a poor sample but still illustrative for its application.

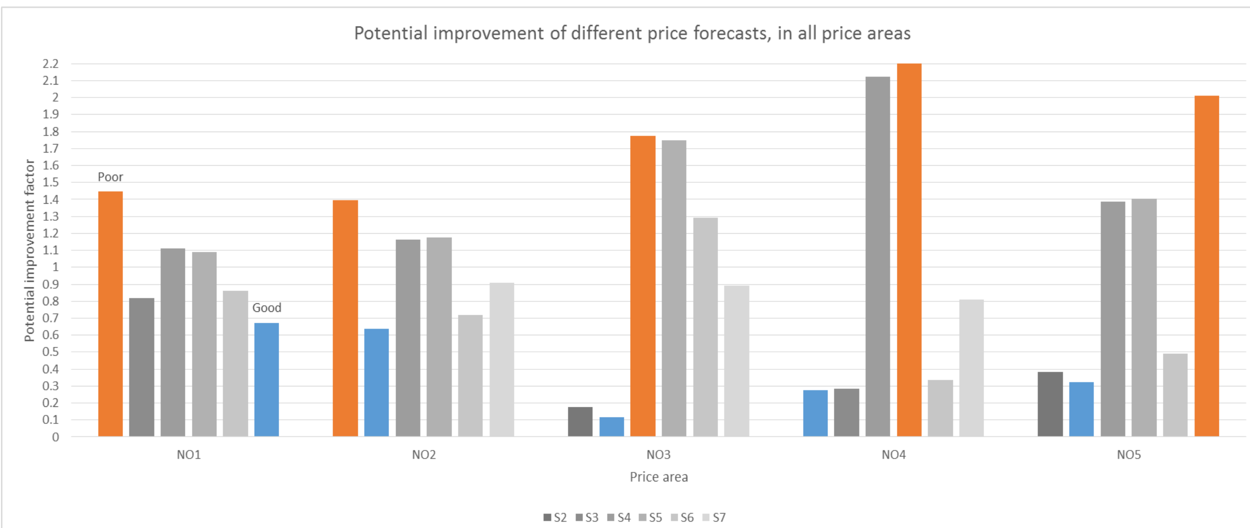

Figure 27 - Price forecast accuracy in different price areas used for price independent bidding. One optimization every second month, starting January 2013, in each price area. Total 30 optimizations. Price scenario 2 - 8.

The potential improvement factor along the y-axis in Figure 27 is calculated as each price scenario's contribution to potential improvement, relative to the average potential improvement in the price area. This factor is used due to the large income variations between the price areas, which would have resulted in a poor graphical presentation. A high improvement factor does simply indicate that the respective scenario has a relatively high potential improvement, and the dominating one are marked with orange colour in each area. The opposite yields for those who are marked with blue, which has the lowest potential improvement, and therefor also results in the most robust income. For instance, if a scenario has a relatively high potential improvement, its price forecast may have deviated more from the spot price, than the other price forecasts. Low potential improvement indicates that the price forecast fits the spot price development relatively good.

Analyst A sores best in all price areas, except in NO1 where Analyst C gives the highest income. The same scenarios from Analyst A are especially good in NO3. Note that S2 is the uncorrected version of the up-to-date price forecast S3, which both is generated by Analyst A. S4-S5 are two workdays old versions of the latter mentioned scenarios, and they are assumed to be especially sensitive to price profile variations. The descriptive price statistics in Section 6.5 indicates that NO3 had the largest price volatility during 2013, which may be the reason why S4 and S5 are the poorest price scenarios in that price area.

A script could be implemented to run more optimizations and get a better sample, but it is not easy due to the fact that there is no control of penalty functions and deviations in system constancy. One would also need to work from two different databases, or copy all price forecasts into new time series to the SHOP-related database. According to experienced developers at Statkraft is the programming work-load approximated to be about one month, without any guarantee of succeeding, for a person with advanced knowledge about VBA and databases. It has therefore not been prioritized within the scope of this master's thesis.

6 The Nordic Power Market during 2013

Until now, the framework and testing of the methodology has been presented. This section will present an analysis of the Nordic power market, Nord Pool Spot, during the year 2013. The objective with this analysis is to identify the market characteristics and fundamental observations such as price development, production, and exchanged volumes with coupled markets like Germany. An introduction that quantifies the technical- and fundamental aspects of the market will be given. Most of the data is collected from a FTP server kindly provided by Nord Pool Spot.

In Appendix II the reader will find detailed supplement to this section presenting the development of inflow, reservoir levels, thermal prices, and CO2 emission rights. Basic information about market pricing of electricity, and potential price drivers are also discussed in Appendix I.

6.1 The Nordic Power System – Production and Capacities

Total production in Norway, Sweden, Finland, Denmark, Estonia, Latvia, and Lithuania amounted to 397 TWh where Sweden represented 37.18 % followed by Norway, Finland and Denmark (Nord Pool, 2014). Figure 28 shows the generation mix in the latter mentioned countries. In total, hydropower is the largest contributor with almost 51 % market share (Appendix II).

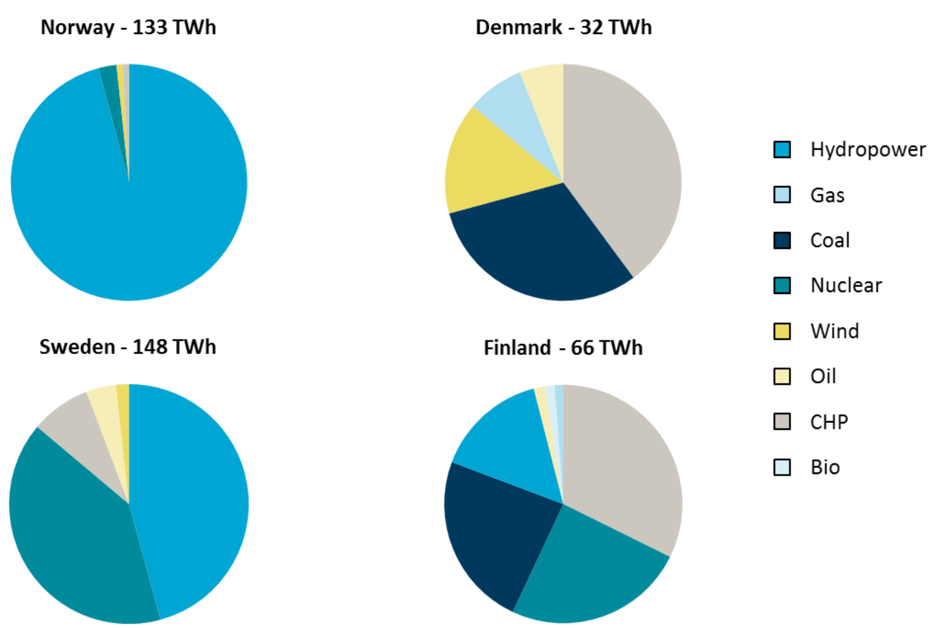

Figure 28 - Generation mix in the Nordic countries Norway, Denmark, Sweden and Finland. (Statkraft, 2013)

Domestic consumption in Norway decreased 0.11 % to 128 TWh from the previous year, while the production decreased 8.85 % to 133 TWh. Hence, Norway was net exporting about 5 TWh with a peak in August (Appendix II). Norwegian electricity production consists of 95 % hydropower, roughly, where Statkraft is the largest producer controlling 11 359 MW, or 36 % of 31 712 MW total domestic installed capacity (Fakta 2013, Energi). This implies that Statkraft has a substantial market share implicitly controlling about 0.36*0.95*133/397*100 = 11 % of the production at Nord Pool.

The interconnections and transmission capacities between the countries are depicted in Figure 29. One can see that Sweden have relatively high domestic transmission capacity ensuring that the consuming areas in the south are supplied from the surplus areas in the north. NO4 is a typical surplus area exporting to the northern part of Sweden and NO3. Southern Sweden have the possibility to exchange power through their interconnections with the rest of the Continent, in the interval of 3000 – 4000 MWh/h. In addition to Norway's 1700 MWh/h (partly through Denmark) it should be reasonable to assume that the spot price in Norway have a positive correlation with the spot price at EEX in Germany; as a result of the strong interconnection with the neighboring countries (KPP, email 2013).

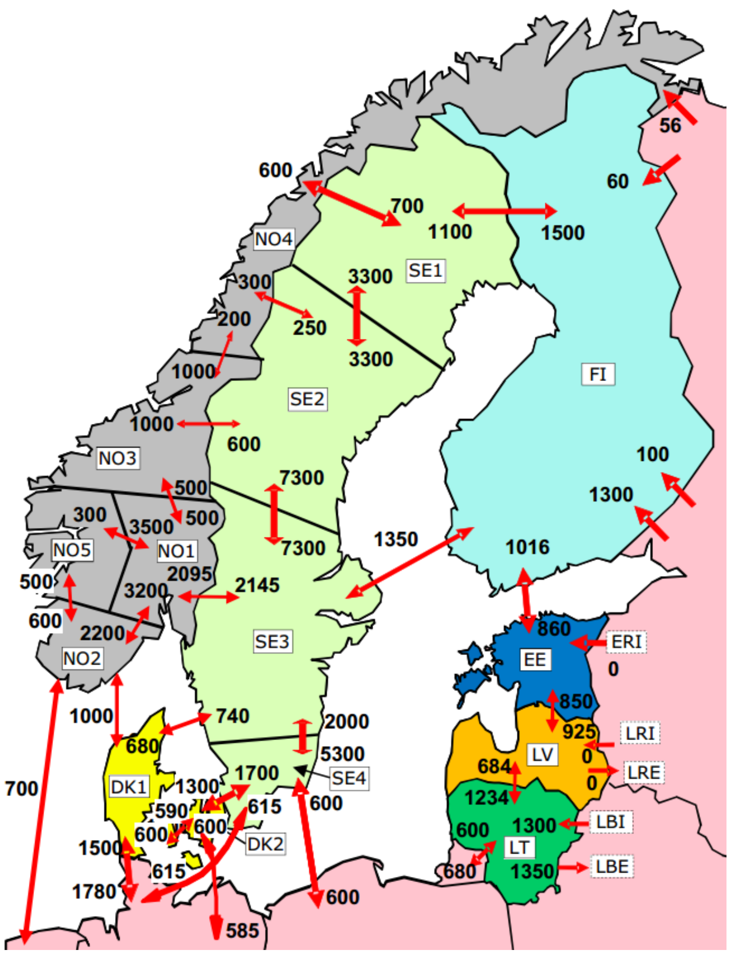

Figure 29 - Exchange capacities [MW] between the Nordic countries (Nord Pool, 2014)

As for Norway, the TSO (Statnett) is planning to increase the exchange capacity with three new cables connected to; Denmark (Skagerrak 4), Germany (NordLink) and England. The first one will increase the capacity between NO2 and DK1 from 1000 MW to 1700 MW with a new HVDC cable known as Skagerrak 4. Skagerrak 4 is scheduled to be operational already in December 2014 (Statnett, 2014). NordLink will establish an exchange capacity of 1400 MW between NO2 and DE, and is scheduled to be operational during 2018. The last cable from NO2 to England is scheduled to be finished during 2020 with the capacity of 1400 MW, given that OED approves the concession application. In total this will contribute to 2800 MWh/h increased exchange capacity with other markets, in addition to the 700 MWh/h link to the Netherlands. As long as the production and consumption develops proportionally, the prices will become more equal within the European markets and Norway will probably benefit from a social economic point of view (Statnett, 2014).

The connections with Germany (DE) and the Netherlands (NL) may have a potential influence on the spot price in Norway, due to their total transmission capacity of 3680 MWh/h with the Nordic market. The capacity with DE alone is about 2900 MWh/h. To put it in perspective were the average hourly energy production, during 2013, 15 227 MWh/h in Norway. Figure 30 gives a full overview of the market coupling with corresponding maximum capacity (MW) and average load (MW), during both 2012 and 2013. Notice that DE has gone from being a net importer, to a net exporter. The highest utilization is found at the NO2 – NL amounting to 80 %, followed by DK2 – DE at 43 % on average.

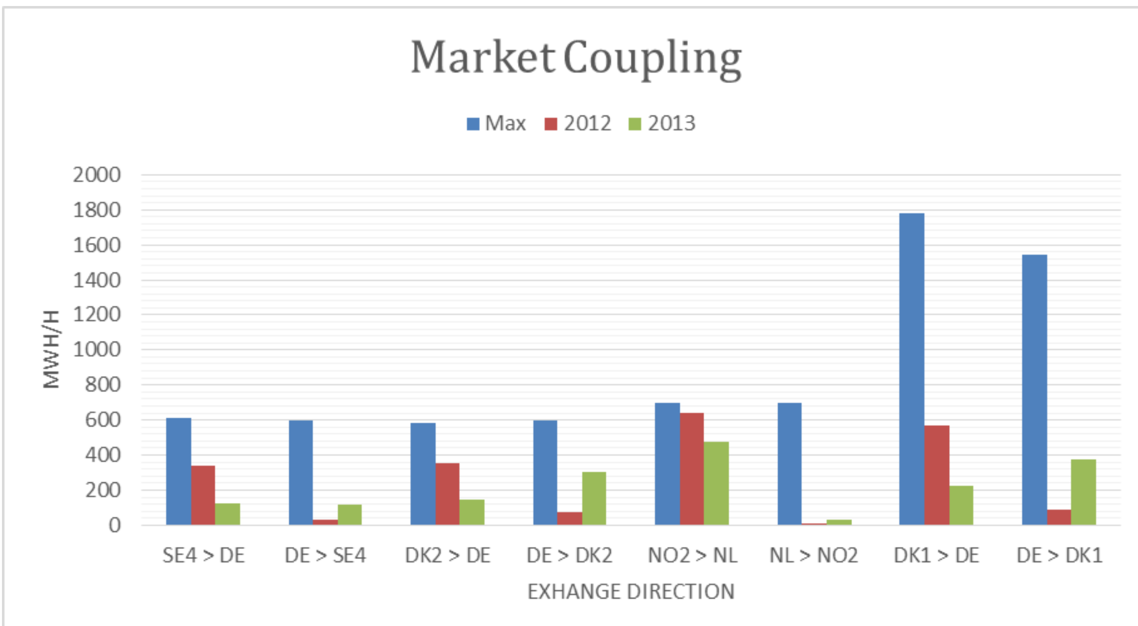

Figure 30 - Transmission (maximum capacity, average 2012 and average 2013) between Sweden (SE4), Denmark (DK1, DK2), Norway (NO2), Netherlands (NL) and Germany (DE). Data: Nord Pool, 2014

According to the collected data in Figure 30 it is only NO2 that is directly coupled with another market, as a net exporter to NL. But the indirect capacity through the other Nordic markets is significantly larger and will be discussed in the following subsection. The monthly exchange, during 2013, between Norway and the connected countries can be found in Appendix II. The exchanged volumes are given both for the Elspot- and Elbas market in the appendix.

6.2 INTERCONNECTIONS WITH GERMANY

The total exchange of electricity with Germany during 2012 and 2013 remained almost unchanged but as Figure 30 shows, did Germany go from being a net importer to a net exporter at these market connections. The energy exchange during 2012-2013 is more elegantly presented in Table 15. Germany export 31.4

TWh during 2013, resulting in a 36 % increase from the previous year at 23.1 TWh. This may have been a result of the extending downward trend in electricity prices, which is about 13 % lower on average than 2012. The price decrease is mostly due to oversupply from renewable and conventional sources, as well as cheaper generation costs for thermal units and a falling demand. Total renewables output, including hydro, biomass, and other forms of green power generation, accounted for almost 25 % of Germany's generation mix in 2013 (Appendix II, Platts analysis of 2013).

Table 15 - Total (direct) energy exchange (TWh) between market coupling connections with Germany (DE) during 2012 and 2013. Data: Nord Pool, 2014

	2012	2013
TO GERMANY	11,09	4,33
FROM GERMANY	1,68	7,00
TOTAL	12,77	11,33

Germany's electricity consumption was 560 TWh, equivalent to 41 % more than the total production at the Nordic market. Solar and wind covered 13.73 % of Germany's consumption with its installed capacity at respectively 35,651 MW and 32,513 MW. The aggregated utilization time for wind production was relatively poor compared with Nord Pool's statistics, 1451 hours compared with roughly 2000 hours (based on data from NO, DK and SE). Solar power amounted to a utilization time of 833 hours. The characteristics of solar- and wind production will also be presented in Section 6.3.

Figure 31 shows the generation mix in Germany during 2013. Solar and wind accounted for 76.9 TWh of the energy production, right behind the third largest source; nuclear power. Coal was clearly the dominating source covering 45.6 % of the electric energy consumption. As mentioned earlier, it is reasoned that the historically low coal prices has contributed with competitive marginal costs. Assuming a coal price at 80 USD/ton equals a marginal cost of 13.56 EUR/MWh, given that the fuel is converted to electrical energy with an efficiency amounting to 100 %. Most of the coal plants are assumed to have an efficiency about 40 %, which gives a marginal cost about 33.90 EUR/MWh.

$$MC_{coal,100\%} = 80\ \frac{USD}{ton} \cdot \frac{1\ ton}{8.14\ MWh} \cdot 1.38 \frac{EUR}{USD} = 13.56 \frac{EUR}{MWh}$$

Currency EUR/USD dated 20.03.2014.

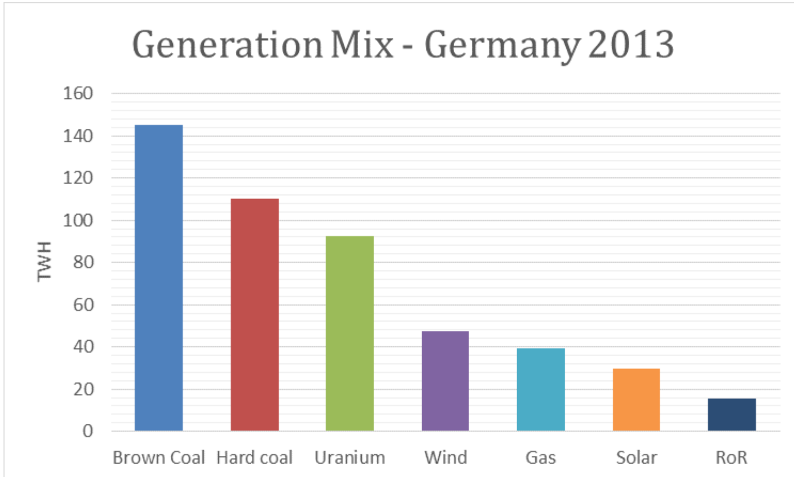

Figure 31 - The generation mix in Germany during 2013. Data: Fraunhofer, 2014

6.3 Intermittent Power Generation – Nord Pool and Germany

Germany has a considerable amount of intermittent power generation as mentioned in the previous section. A comparison of the wind- and solar production in Germany, and the Nordic market is provided in Figure 32. The wind production in the Nordic market amounted to 22.2 TWh, or 5.59 % of the total generation mix. This means that Germany produced more than the double amount of NP wind, as well as 29.7 TWh solar in addition to this. Solar production at Nord Pool is assumed negligible due to lack of data.

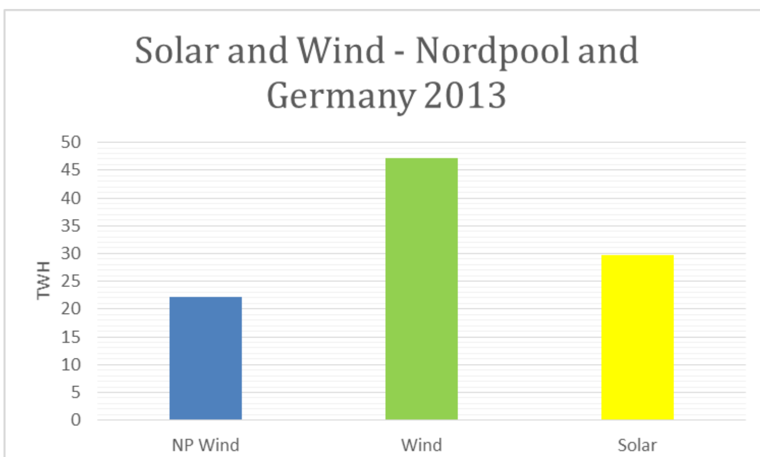

Figure 32 - Wind and solar production (TWh) at Nord Pool and in Germany. Data: Nord Pool and Fraunhofer, 2014.

The contribution to wind power production from the respective countries in the Nordic market is illustrated in Figure 33. The figure indicates that Denmark is the largest contributor with 11.3 TWh, followed by Sweden and Norway, at respectively 8.57TWh and 1.58TWh. The utilization time varies between 1880 to 2300 hours, compared with the average utilization time of hydropower at 4000 – 4200 hours.

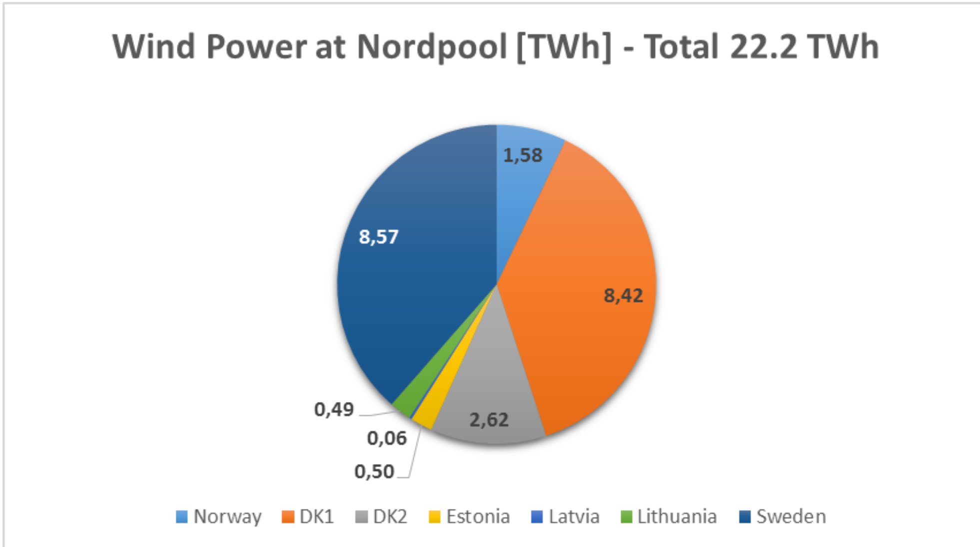

Figure 33 - Wind power production mix at Nord Pool. Data: Nordpool, Markedskraft and Vindportalen, 2014

The seasonal characteristics of the dominating, intermittent power generation is that solar power production peaks during the summer season, while the wind power often peaks during the winter season. Figure 34 illustrates this statement with actual, monthly production in Germany during 2013. The solar utilization is low during the winter, as expected, with limited irradiation from the sun. One the other hand we got stronger utilization of wind power during the winter, due to the so called *Westerlies*. The Westerlies are the prevailing winds between 35 and 65 degrees latitude blowing into the Northern Hemisphere from southwest. They are strongest during the winter when the pressure is lower over the poles. Hence, the wind potential is therefore largest during the winter season (Appendix II).

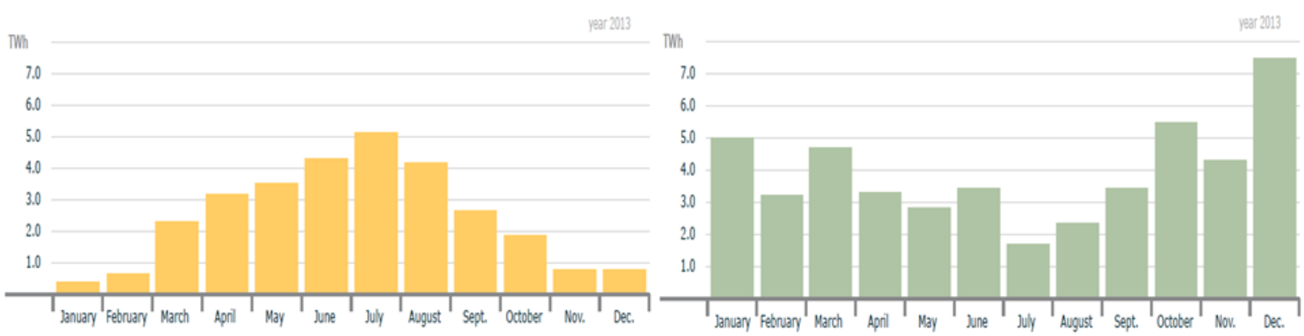

Figure 34 – Solar- (yellow) and wind (green) power production in TWh per month during 2013, Germany. (Fraunhofer ISE, 2014)

Looking at the transmission line between Norway (NO2) and Denmark it may be possible to reveal the wind production pattern, due to Denmark's relatively large amount of wind power. The MC of wind power might often be lower than MC of hydropower, which creates incentives to import from Denmark when they are in surplus of wind power supply. Figure 35 shows a graphical presentation of the import (orange line) and export (blue line), with Norway as a reference. Norway seems to be importing more than average during the winter season. Comparing the orange graph with the wind production characteristic in Figure 34, it has almost the same pattern. This observation is a relevant case for the analysis section, with a optimization of NO2 one day in March/April under potentially high import of wind power, and one day in July/August when imports and wind generation seems to be low.

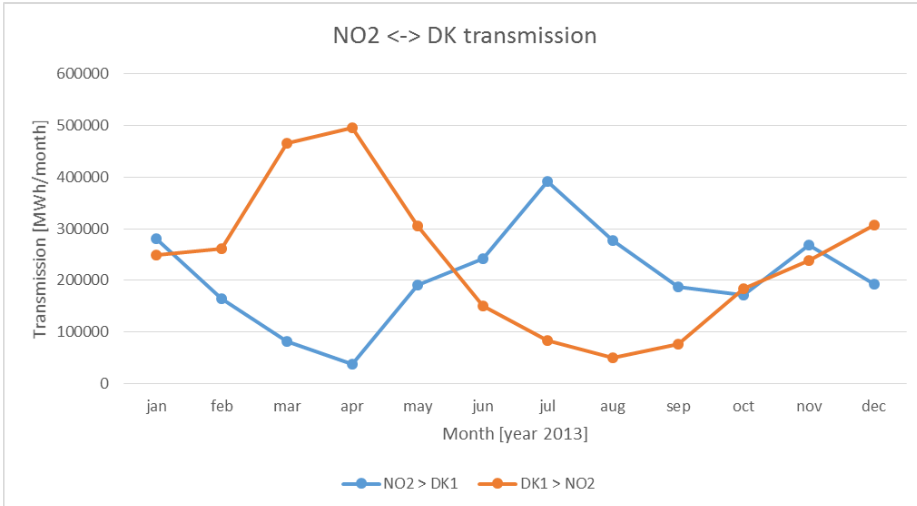

Figure 35 - Transmission between NO2 and DK1 per month during 2013. Data: Nord Pool, 2014

6.4 TURNOVER – THE PHYSICAL NORDIC MARKETS

The three physical markets Elspot, Elbas, and the regulating market experienced increased turnover volume from 2012 to 2013 in Norway, Denmark, and Sweden. Table 13 indicates the percentage of total aggregated turnover-volume in all of the physical markets. The table shows a trending increased volume in the sequential markets turnover. This trend was also stated in the literature review in Section 2.

Table 16 – Percentage (%) of total turnover in the physical markets during 2012 and 2013. Data: Nord Pool, 2014

	2012			**2013**		
	NO	SE	DK	NO	SE	DK
ELSPOT	99,11 %	98,47 %	97,40 %	99,14 %	98,26 %	97,09 %
ELBAS	0,16 %	0,89 %	1,50 %	0,19 %	1,11 %	2,03 %
RM	0,74 %	0,63 %	1,10 %	0,67 %	0,63 %	0,88 %

Table 14 denotes a more elegant presentation of the change in turnover volume from 2012 to 2013. The average increased volume at Elbas amounts to 30.25 %, which is a significant change and strengthen the motivation for the research being pursued in this thesis. Moreover, we observe a decreased volume in the regulating market which possibly can be argued with that the need for balancing is met by increased participation in the intraday market, Elbas. It is reasonable to assume that the positive volume-trend in the intraday market is caused by producers with a relatively unpredictable power generation, as for example solar- or wind.

Table 17 - Change (%) in turnover volume from 2012 to 2013. Data: Nord Pool, 2014

	NO	SE	DK
ELSPOT	11,33 %	-5,19 %	3,10 %
ELBAS	32,78 %	18,08 %	39,88 %
RM	1,76 %	-5,97 %	-17,03 %

Summarizing the observations carried out so far in this section. Current-, and planned-, interconnections between the countries, characteristics of intermittent power generation, and increased participation in sequential markets. Although the solar market share at Nord Pool is negligible there is still a considerable amount of intermittent wind power being penetrated into the Nordic market, both within the participating countries and through market couplings. Some of this findings may come to help while discussing the results later in this thesis.

The final subsection will focus on the market environment in Norway, and highlight observations that can be used to re-create scenarios at particularly interesting dates.

6.5 PRICE- AND VOLUME DEVELOPMENT IN NORWAY

Electricity prices and volume couplings will be carried out from this section as a fundament for selecting, and discussing, historical bidding scenarios in the analysis section. The objective is to search for characteristic observations like:

1. Periods with relatively high spot price
    - Upper part of the bidding-curve (supply). Price is sensitive to changes in quantity.
2. Periods with relatively low spot price
    - Lower part of the bidding-curve (supply). Price is less sensitive to changes in quantity.
3. Price volatility
    - Large- or small variations in the spot price
4. Deviations between the day-ahead and regulating prices
    - Low deviations: The market is in balance
    - High deviations: The market is in imbalance, hence strong incentives for regulation
5. Production and consumption
    - Net export, and association with intermittent power production (low MC)
6. Deviations in estimated- and actual production (and consumption)
    - Market predictability and weather conditions
7. Exchanged volumes intraday market
    - In search of marginal price areas (or countries). Correlation with point 5 and 6?

Documentation of the observations can be found in Appendix II, under *Documentation of price and volume*.

6.5.1 Price Observations

Data regarding the spot price and deviations from regulating price is illustrated in Figure 36. The sample space is collected hourly through 2013 and is represented as moving average +/-2 days, hence a smoother curve that is easier to interpret. The spot price is relatively high during the winter period and it reaches 55.18 EUR/MWh around April 9th. This is a typical example of a situation where the demand intersect with the supply[6] at high marginal costs, thus giving a sensitive price with respect to small changes in the turnover volume. The largest deviation in price paid for regulation, with spot price as reference, is marked with 36.49 EUR/MWh around January 16th. This implies that the production around that day was insufficient and needed to be regulated up to meet the demand.

Recall the conceptual demand and supply plot, with the supply curve arrange in ascending MC order, shifting either right or left with respect to the supply-side sell bids for low MC hydropower (Appendix II). One important driver for the spot price on electricity is the SRMC of 40 % efficiency coal plants (Statkraft, 2013), due to its large market share in the Nordic and competitive marginal costs. Generally speaking, this is only true when the hydrological balance is close to normal, hence wet periods will drag the spot price down from SRMC due to hydropower producers trying to avoid having too much water in their reservoir. And vice versa during dry periods, when the hydropower producers usually wish to save water.

According to relevant market conditions during 2013, given in Appendix II, the hydrological balance had a peak above its average during week 19 to week 22 (May 6th to June 3rd). It seems like the spot price in Figure 36 reacted with a significant decrease when the wet inflow forecasts came in between April and May, as a result of lower expected water values. Moving on to the coal price development at the API 2 index[7], in Appendix II, one can observe relatively constant price with a year-high during January and year-low during the summer. The gas price were year-low during January and held a constant 30 % price increase during the rest of the year. CO_2 emission rights had a peak in end-January and year low during February. The peak in the spot price for electricity in the beginning of April could be explained by the record-low hydrological balance in Norway at the time, near all-time low.

A general summery of the seasonal price volatility is as follows:

- Top 30 volatile days: January – July
- Bottom 30 volatile days: September - March

[6] The market bid-curve is the market supply curve. An example is given in Appendix I.
[7] API Index 2: Price benchmarking for coal imported to northwest Europe.

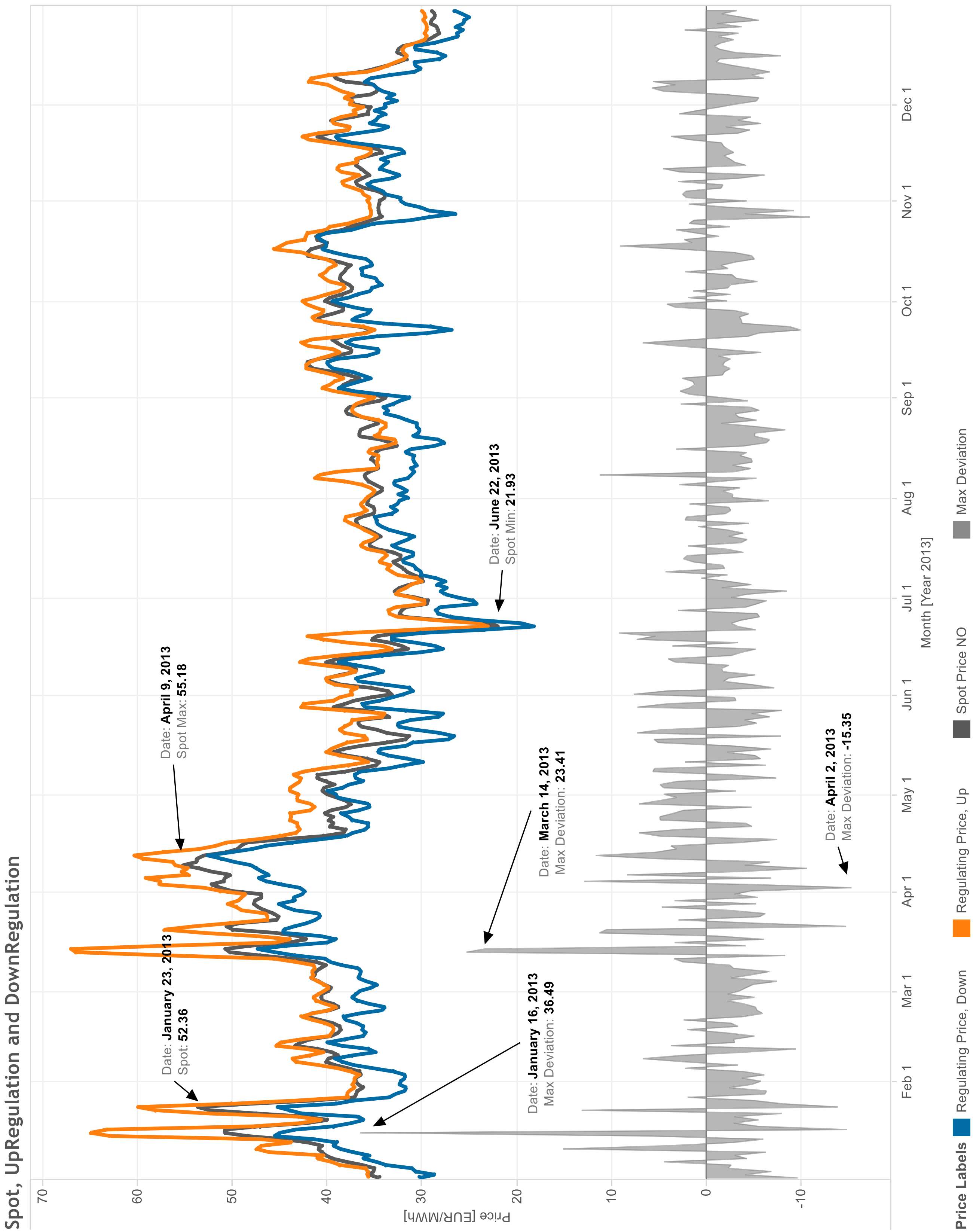

Figure 36 - Spot price and price paid for up- and down regulation. Grey area represents the dominating (largest) price deviation for regulation with spot as reference. Data: Nord Pool, 2014

During the beginning of the summer season the spot price reaches its minimum at 21.93 EUR/MWh around June 22nd. A low average spot price during the summer is common due to lower demand and expected inflow to the reservoirs. In the regulating market we find that the most negative deviation in down regulation, measured against the spot price, is -15.35 EUR/MWh about 2nd of April, implying that the demand most likely turned out to be lower than the estimates or deviations from estimated production. The latter argument is normal during spring and summer, when intermittent power production from run-of-river (ROR) is difficult to predict due to flood-periods. The installed capacity of ROR in Norway is increasing, and this is also reflected in the regulating prices during flood-season (Markedskraft, 2014).

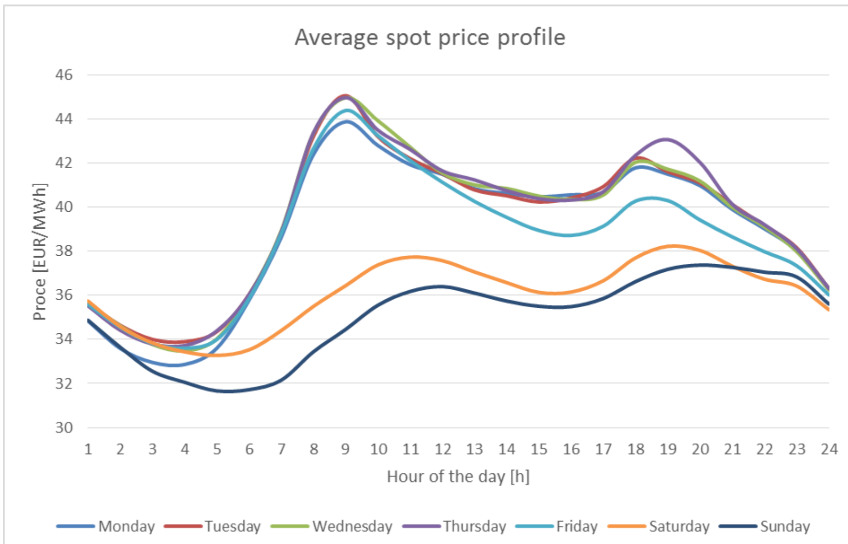

Figure 37 - Average spot price profile for each day during a week

Figure 37 depicts the average price profiles for the respective weekdays. Due to lower demand during the weekends the price gets less sensitive, hence the "peak shave" for Saturday and Sunday. Thursdays seems to have the highest average. The profiles does naturally vary with respect to quantity demanded, or seasons, but the figure gives an overall impression of how it might look like.

The descriptive statistics for the spot- and area prices are given in Table 18. It is obvious that the spot price can be volatile when it peaks around +/-50 % measured from day-to-day. The area price in NO3 seems to be the most volatile with a standard deviation about 9.22 %, followed by NO4, NO1, NO5, and NO2 during that particular year. The calculation is based on daily average price, and the intra-day price statistics can therefore give other volatility rankings with respect to hour of the day.

Table 18 - Descriptive day-to-day data for spot- and area prices during 2013. 364 observations. Data: Nord Pool

	Spot	NO1	NO2	NO3	NO4	NO5
Mean	-0.02%	-0.03%	-0.03%	-0.03%	-0.03%	-0.03%
Standard Deviation	8.13%	6.94%	6.71%	9.22%	8.82%	6.75%
Min	-51.15%	-50.89%	-50.89%	-53.16%	-53.16%	-50.89%
Max	49.25%	42.04%	42.19%	56.98%	53.44%	42.04%

The day-to-day percentage change and seven-days-rolling standard deviation for the spot price is illustrated graphically in Figure 38. The standard deviation is calculated +/- three days, including the respective time step to give a smoother graph and indicate volatile periods (weeks). The plots shows that the spot price is particularly volatile during the low-price at June 22nd with a 51.15 % decrease from the previous day. A few days later, at June 24th, the price jumps up 49.25 % compared with previous day's spot price. The same period is also indicated as price volatile in the standard deviation plot. It is reasonable to assume that the negative price shifts, causing the low average price, is due to energy and/or effect surplus, which will be described more in detail later in this section. On the other hand, the end of October seems to be a relatively price stable period.

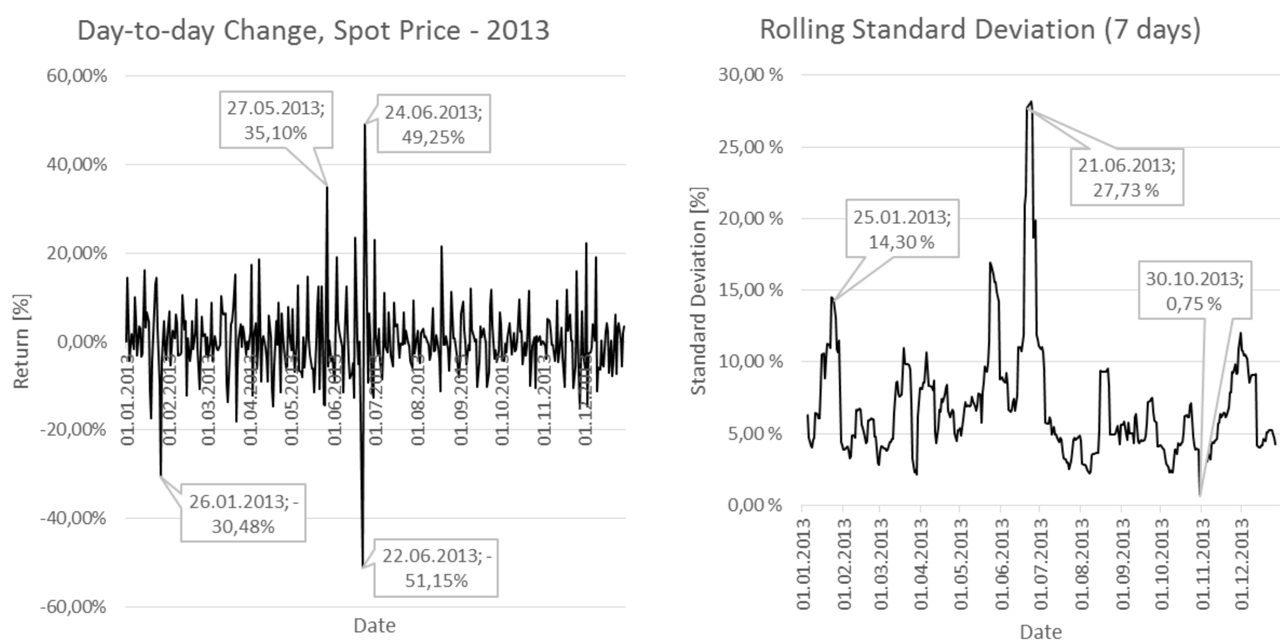

Figure 38 - A plot of descriptive price statistics; day-to-day spot price change (left) and day-to-day rolling standard deviation (right). Data: Nord Pool

Figure 38 depicted the day-to-day statistics. Intraday, hourly statistics are presented in Figure 39. The left plot in the figure is the maximum- (blue graph) and minimum (red graph) percentage change from one hour to the next, during a given date. The right plot in Figure 38 is the intraday standard deviation, where the data sample is 24 hours for the respective date. The intraday spot price is extremely volatile during June 23rd with a standard deviation of 44.52 %, meaning that the hourly spot price were varying with that percentage around its average value during that particular day. The largest hourly change in spot price amounted to 144.95 %.

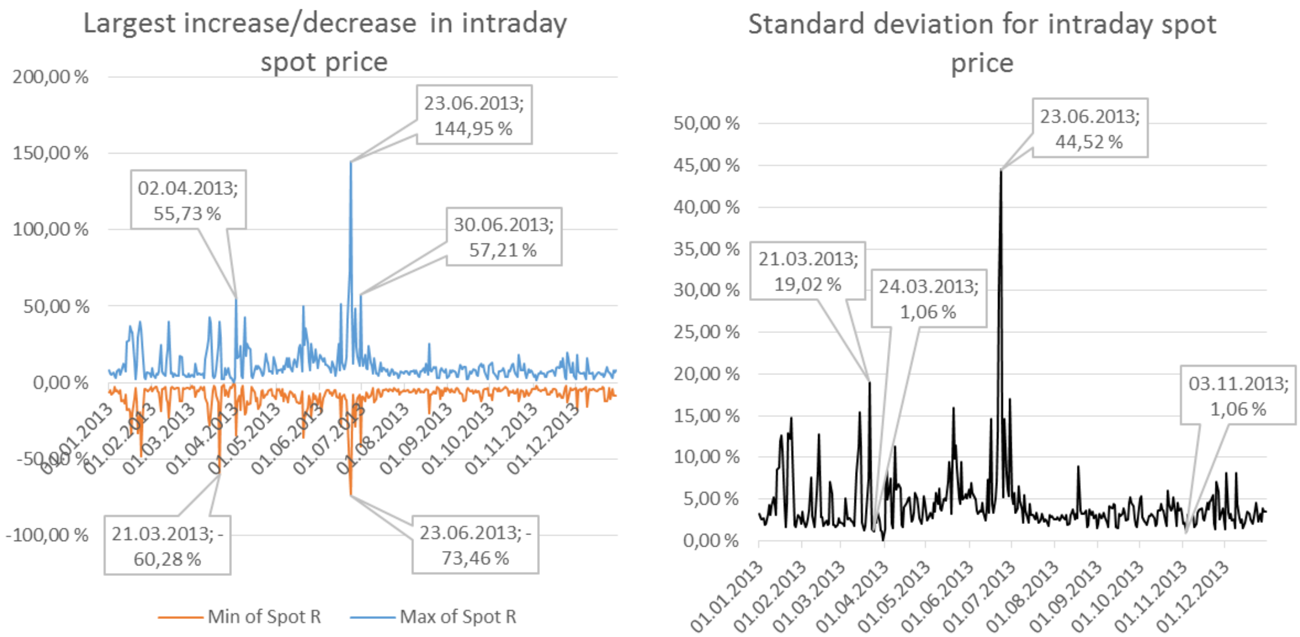

Figure 39 - A plot of descriptive statistics; intraday spot price change (left) and intraday standard deviation (right). Hourly data: Nord Pool

The high price volatility during the summer may be a combination of dry inflow forecasts and relatively low reservoir fillings (Appendix II). During the same period one can see that NO2 peaks its exports to NL, while Norway in general is exporting at yearly maximum during July to August, as well. This export may be associated with the lowest production of intermittent power during the year, due to the fact that the largest installed capacity of wind power, at Nord Pool, is found in Denmark and Sweden. Thus, decreased supply of low MC generation in the neighboring countries creates incentives for importing electricity from Norway at relatively low MC.

Some relationships worth pinpointing from the price behavior is that days with low price volatility is mostly Sundays and Saturdays, as well as other red-calendar-days. It is not surprising due to a low demand intersecting the supply curve at less price sensitive areas. Days with high price volatility is bit more random with respect to day of the week, but it seems to be a combination of unpredictable weather-periods, like flood- and precipitation seasons, and outdated price forecasts due to red-calendar-day the previous day. The highest price shifts recorded are during the summer, and typically a day with outdated price forecasts as mentioned in the previous argument.

The large price shifts does often occur due to limited flexibility (Statkraft, 2014), and the system will return to a more normal situations after a while (mean-reverting price). Examples of when a price shift potentially can appear is listed below:

- **Effect deficit**: Low night price, and high day price. Often caused by low temperatures and high consumption. The price volatility is high during the day. Usually it only affects peak hours, due to low consumption at night. Duration is about 4-5 days.

- **Energy deficit**: High night price, and high day price. Lower volatility than effect deficit. Often caused by dry hydrological status, especially spring time when reservoirs are emptied upfront the spring/summer flood. Increasing price over time, due to higher sell-bids to reduce production. Can be combined with effect deficit during peak hours. Duration is often more than one week.

- **Energy/effect surplus**: long periods with low prices, followed by price collapse. For example; high reservoir level + precipitation + low consumption (+ nuclear). Typically during summer where inflow is greater than production capacity, hence rapidly increasing reservoir levels without enough consumption to balance the supply side. Can also take place during the fall, when reservoirs is nearly full before the winter season hits - If the temperatures stays mild, power may be dumped into the market to avoid spillage. This can cause low prices for a period, and suddenly jump back (mean-reverting).

The regulating market which is operated by the TSO, where the market participants has committed their capacity for up- and down regulation within an operational hour. If there is imbalance in production and consumption, the production is regulated to achieve equilibrium. The monthly development of the average regulating prices, and the spot price, is depicted in Figure 40. This figure is only meant for illustrating purposes. The bars in the figure is attached to the secondary axis, which indicates if it is up- or down regulation that dominates, meaning which regulation price deviating the most from the spot price. According to the figure, down regulation is on average the dominating type of regulation.

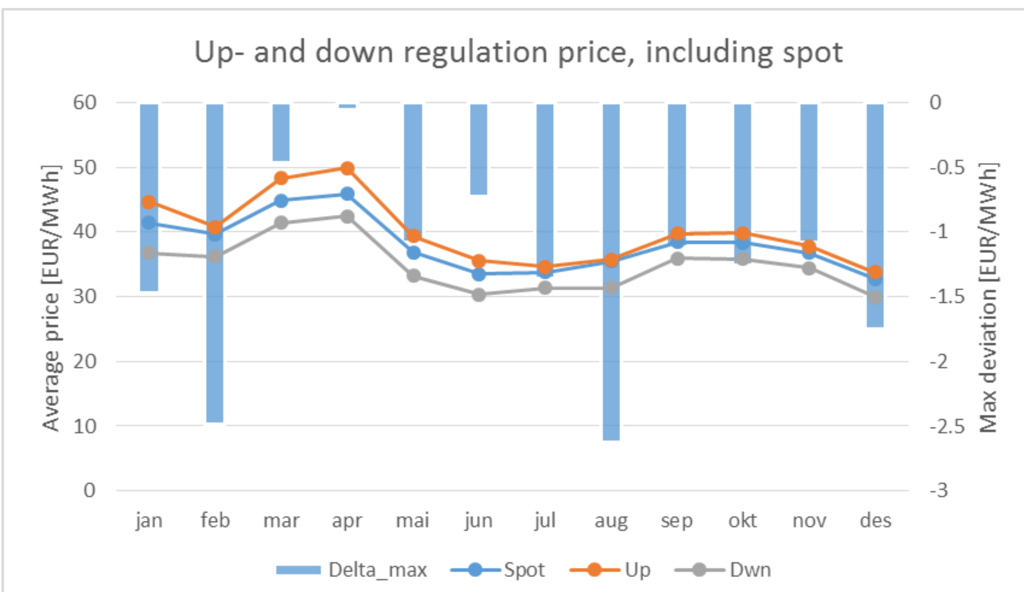

Figure 40 - Average up-regulation-, spot- and down-regulation price per month in 2013. The seconday y-axis indicates dominating regulation (largest gap w.r.t. spot price). Data: Nord Pool 2014

The producer who has committed capacities in the regulation market, will get paid the regulating price in cases of up-regulation, and buy back at regulating price in case of down-regulation. The producer will in both cases profit from the deviation from spot price. Looking at Figure 40 one can see that the spot price lays close to the up-regulation price during the whole year, which indicates smaller incentives for up-regulation. On the other hand does the down-regulation price indicate stronger incentives for down-regulation, especially during August. A typical reason for this deviation could for example be large inflow, hence ROR that covers some of the committed production in the day-ahead market.

Figure 40 depicted the seasonal characteristics of the regulating market during 2013. Figure 41 shows the daily measurements of the previous figure. The plot is maximum deviation from spot price, up- or down regulation, and a seven days moving average to give a clearer indication of the periodical development. The maximum deviation in up-regulation peaks at January 16th and March 13th, which indicates strong incentives for increasing the production to meet the demand. It could for example be caused by significant deviations in the weather forecast which turned out to be much colder than expected, or a weather contributing less to intermittent power generation like wind and ROR than expected.

Maximum peak in down-regulation was April 2nd and January 17th, which could imply stronger needs for decreasing the production to get in balance with the demand. January 17th could be a ripple effect of the deviation the day before.

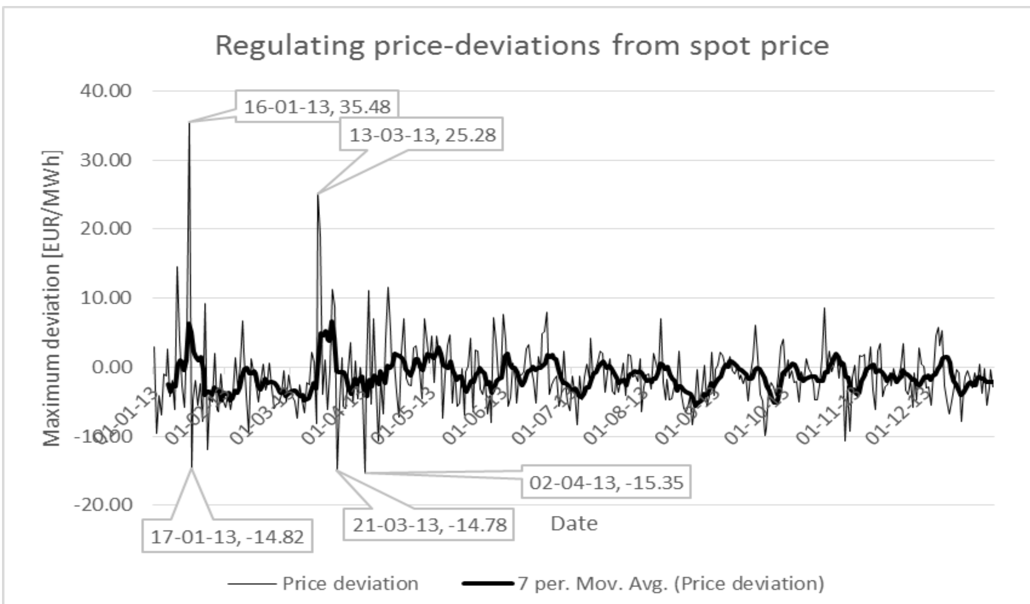

Figure 41 - Daily, maximum deviations between regulating price and spot price. Data: Nord Pool 2014

The following price observations are carried out in Table 20, where the dates are chosen with respect to the intraday statistics. For more documentation and more details, please see the tabularized overview in Appendix II.

Table 19 - Price observations; high, low, volatility, and deviations from the regulating price (Appendix II).

PRICE OBSERVATIONS	INFO
HIGH SPOT PRICE	The highest price levels where in January and April. Max value: 58.54 (8. Apr), 56.37 (2. Apr), 56.36 (21. Mar)
LOW SPOT PRICE	The lowest price levels where in June and December. Min value: 17.48 (22. June), 19.18 (23. June), 25.96 (30. June)
HIGH PRICE VOLATILITY (ROLLING 7 DAYS)	June and May where characterized with high price volatility. Around June 19th - 27th and May 24th - 28th. Intraday std. dev.: 44.52 % (23. June), 29.84 % (22. June) and 19.02 % (21. Mar)
LOW PRICE VOLATILITY (ROLLING 7 DAYS)	October, March and August where characterized by low price volatility. Around October 30th - 31st, March 27th - 29th and August 6th-8th. Intraday std. dev.: Mostly red-calendar-days with low demand. 1.06 % (24. Mar), 1.06 % (3. Nov) and 1.10 % (30. Mar)
PRICE OF UP- AND DOWN REGULATION	The highest deviation from spot price is on average down regulation at -1.29EUR/MWh, and the deviation is most significant during August and February. Max up: +35.48 (16. Jan), +25.28 (13. Mar) Max down: -15.35 (2. Apr), -14.48 (17. Jan) Neutral: +0.51 (7. Jul), -0.59 (18. Dec)

6.5.2 Volume observations

Volume observations such as production, consumption, and turnover volumes are summarized in this subsection. The chapter is introduced by Figure 42 showing the Norwegian production and consumption per month, as well as the average- and monthly wind power production at the Nordic market. The wind production is included since it could be a good indicator for Norway’s net export, which is the blue graph subtracted for the red graph.

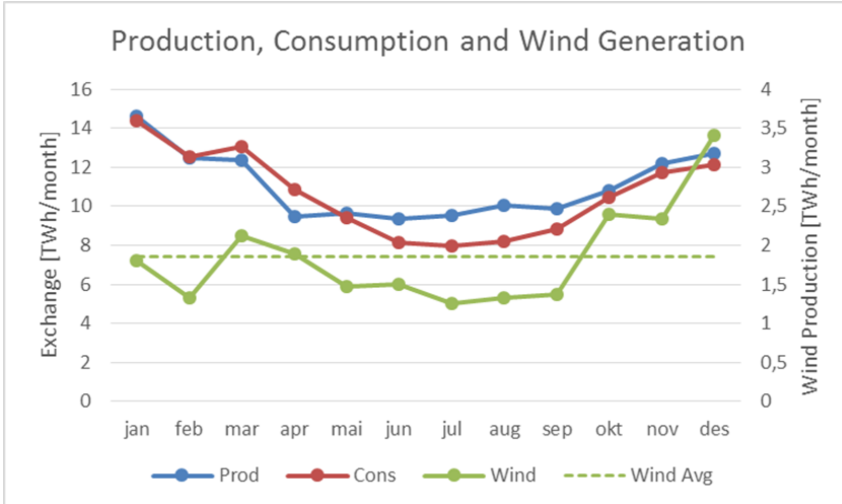

Figure 42 - Production and consumption in Norway [TWh/month]. Secondary axis; wind power production at Nord Pool (mainly SE and DK). Data: Nord Pool and Markedskraft 2014

Quantity of exchanged volume at the day-ahead- and intraday market can be found in Appendix II, for all of the transmission lines with neighboring countries. The appendix shows that Norway had a peak in net exports at the Elbas market during July. The peak in Elbas-import was in April. The most utilized transmission lines for Elbas trades were NO1-SE3 and NO2-DK1. The export at these lines is significantly greater than the imports, which can indicated that neighboring countries is more active in the intraday market. Norway was overall net exporting 72.1 GWh in the Elbas market during 2013. In comparison, they had an overall net export in the Elspot market amounting to 1940 GWh.

Statnett collects data regarding estimated production and consumption for the following day. Surprising, and price driving, factors may contribute to deviations from these estimates measured against the actual production and consumption. For example if the weather causes demand shifts, or generators being shut down in case of short circuits or outages in the power grid, thus resulting in a potential supply shift. Figure 43 shows the summarized deviations for each month during 2013, both with respect to production (blue) and consumption (green). The estimates for domestic production within Norway missed with 50.7 GWh on average, per month. And the estimates for consumption with 17.3 GWh on average, per month.

The deviation is defined as estimated value subtracted for the actual value. In Figure 43 the deviations are labeled as delta production and delta consumption. Delta production peaks during July and January, where the first one may be caused of large amounts of inflow, hence strong incentives for down-regulation as already discussed in the previous subsection. In January, one can see that there in general where estimated less consumption than actual, e.g. due to cold weather. In addition, the production had too high estimates, so the overall effect seem to result in balance.

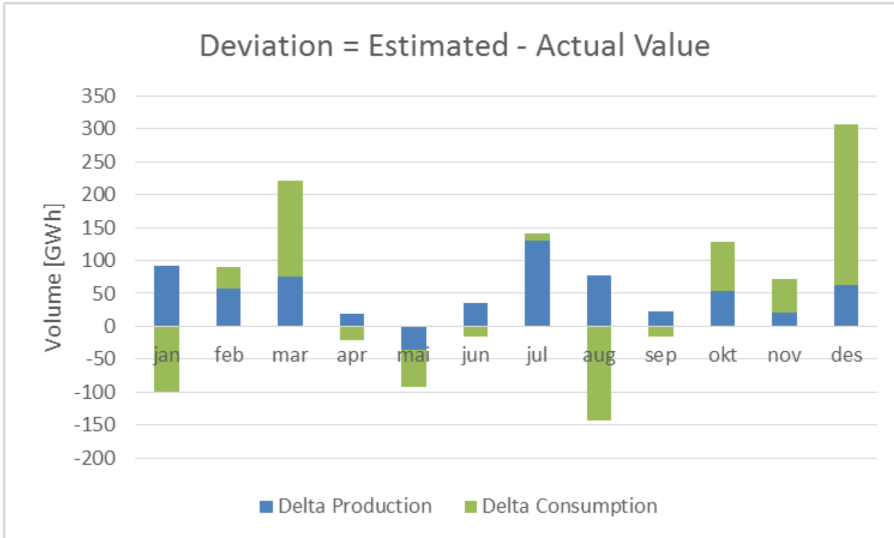

Figure 43 - Deviations from estimated production and consumption, measured against actual data.

Delta consumption peaked 17th of May with 29 405 MWh, followed by December 24th at 24 882 MWh. As we know, these particular dates are red-dates in Norway and the consumption was obviously estimated to be much higher than actual. On the other hand, the estimates where scarce during January 2nd and May 21st, amounting to a deficit of -29 252 MWh and -19 097 MWh. This observations can be found in Figure 44, showing the daily deviations in consumption (left plot) and production (right plot), with respective 10 days moving average marked with the thick, black line.

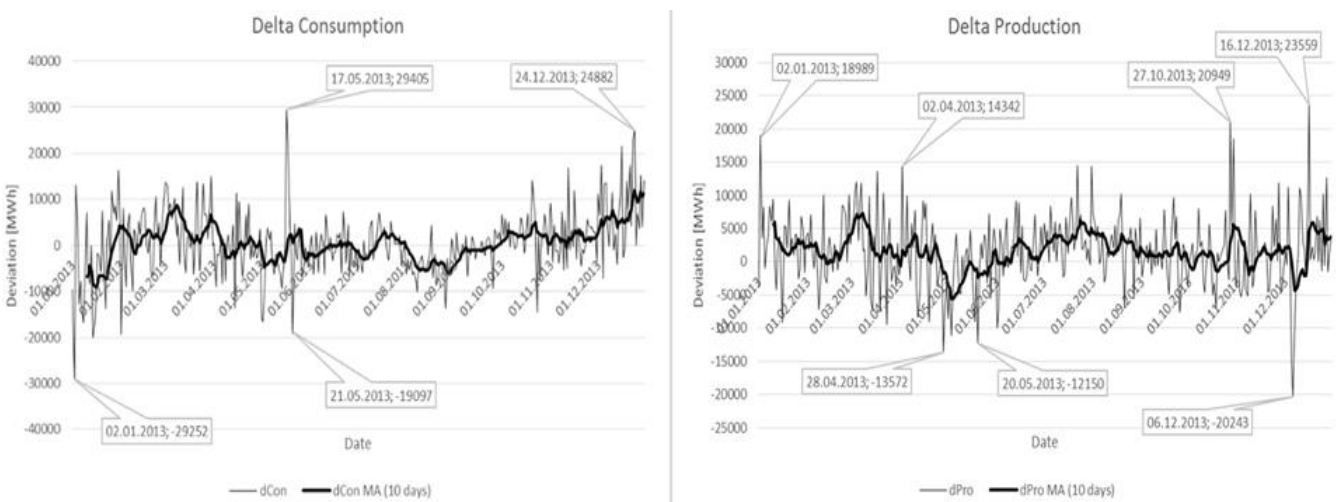

Figure 44 - Deviations in estimated and actual daily data; consumption (left graph) and production (right graph). Data: Nord Pool 2014

Delta production reached its year-high at December 16th and October 27th. Year-low where recorded at December 6th and April 28th. In total, the production deviated most from its actual values during July where the estimates were too high.

A full overview of relevant volume observations are listed in Table 20.

Table 20 - Volume related observations in the power markets during 2013

VOLUME OBSERVATIONS	INFO
ELSPOT NET EXPORT	High during August, low during April on average. Max: 91.7 GWh (20. May), 90.7 GWh (29. May) and 89.8 GWh (27. May) Min: -96.4 GWh (4. May), -92.4 GWh (14. April) and -91.2 GWh (5. May)
ELBAS NET EXPORT	High during July, low during April Highest utilization: NO1 - SE3 and NO2 - DK1
DELTA PRODUCTION	High during late summer (inflow period), low during April Max: 23.6 GWh (24. Dec) and 20.9 GWh (27. Oct) Min: -20.2 GWh (6. Dec) and -13.6 GWh (28. Apr)
DELTA CONSUMPTION	High during December, low during summer-start Max: 29.4 GWh (17. May) and 24.9 GWh (24. Dec) Min: -29.3 GWh (2. Jan) and -19.1 GWh (21. May)
WIND PRODUCTION @NORD POOL	Max: 172.2 GWh (24. Dec), 167.6 GWh (28. Nov) and 162.3 GWh (21. Dec) Min: 6.5 GWh (26. Jul), 7.0 GWh (25. Jul) and 9.8 GWh (27. Jul)
WIND & SOLAR @GERMANY	Max wind: 26.3 GW at 18:15 (5. Dec) and 563 GWh (6. Dec) Max solar: 24 GW at 13:30 and 204 GWh (21. July)

7 River Systems

A presentation of certain river systems are given an introduction here as they will be used later in the report. The river systems are selected to create a diversity with respect to capacity, complexity, and degree of regulation (flexibility). In this section, both technical- and operational data will be presented for the following three river systems; Leirdøla, Røssåga, and Vik. The formula for degree of regulation is given in Appendix I.

7.1 Leirdøla

Leirdøla consists of one reservoir and one station as depicted in Figure 45. The total capacity in the reservoir is equivalent to 187 GWh, and the degree of regulation is about 0.4, meaning that the yearly average inflow is 2.5 times larger than the reservoir capacity (Appendix I). The reservoir can therefore be interpreted as small-/medium sized, relative to its yearly inflow.

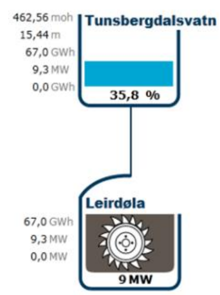

Figure 45 - Topology of Leirdøla river system

The maximum generation capacity at the station is 125 MW. Yearly production at Leirdøla amounts to 451 GWh, on average, and the utilization time is therefore 4100 hours. According to the station's efficiency curve it has a *best point* at 110 MW, giving the highest electricity generation per unit of discharge. If the water discharge is increased by 30 % from best point, the corresponding increase in generated power is only 25 % when reaching 115 MW.

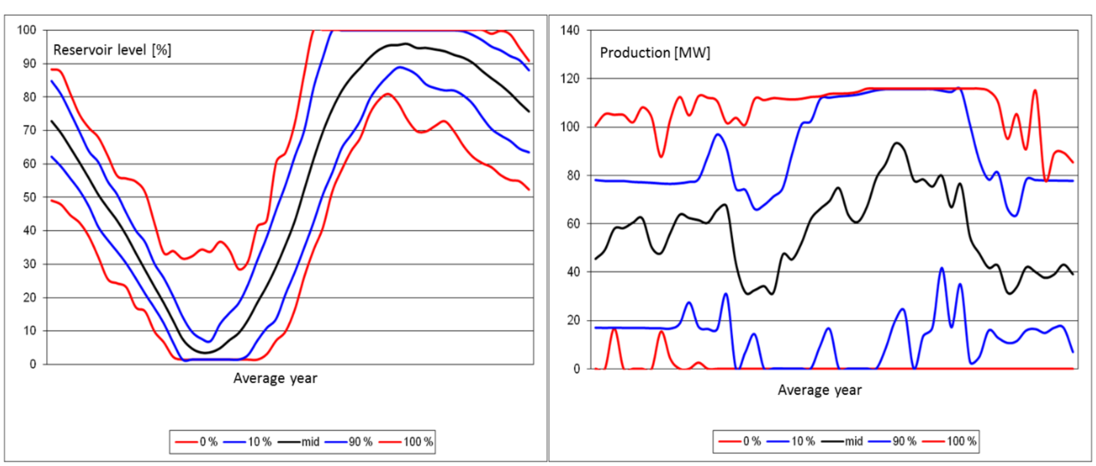

Figure 46 - Leirdøla historical reservoir fillings and production during a year. Source: Statkraft, 2014

Figure 46 depicts the historical reservoir fillings (to the left), and historical production (to the right), during a calendar year. The red graphs represents 0 %- and 100 % percentiles, the blue graph 10 %- and 90 % percentiles and the black graph is the average value. Hence, the red graph the most extreme scenarios recorded during the data sample.

The low degree of regulation gives high production during the summer, due to scarce storage opportunities. The dominating inflow tends to come during late-summer and the discharge capacity at the plant may become too small to balance the inflow, usually resulting in very low water values.

The seasonal couplings are especially challenging for Leirdøla since the water value is relatively sensitive. For example during the spring, when the reservoir has to be nearly emptied to be ready for storing future inflow, as seen by the dip in reservoir levels in Figure 46. Another example could be before the winter season where the reservoir should be as full as possible to be prepared for the winter, and until the next period with inflow. The plant is very flexible during the winter but the water value is also relatively high.

7.2 RØSSÅGA

Røssåga is a river system in the NO4 price area and it consists of a series cascade reservoir system with three reservoirs and two plants. The total reservoir capacity amounts to 2245 GWh, and the plants can generate up to 525 MW at their total maximum limit. In average, Røssåga produces 2528 GWh yearly. The water route in the system spans from 247 to 402 masl and the topology is depicted in Figure 47.

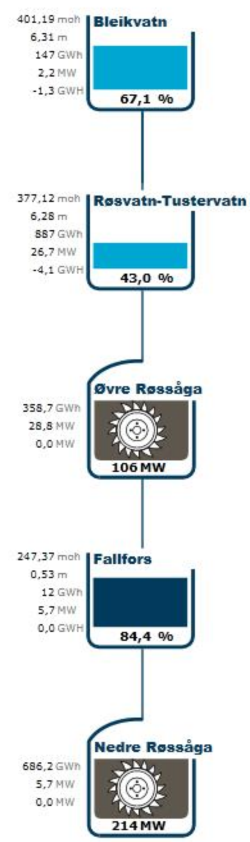

Figure 47 - Topology of Røssåga river system

Bleikvatn is characterized by its high degree of regulation. The only inflow to the reservoir is from the natural catchment area and it can store up to 218 GWh of water, in addition to its flexibility to tap water into Røssvatn who has the largest capacity.

Røssvatn is the second biggest lake in Norway with a capacity of 2016 GWh. The yearly inflow to this reservoir is greater than the storage capacity, hence a regulation degree about 0.7. It is therefore important to manage the water through Øvre Røssåga plant in an optimal way, avoiding spillage. Especially when it is near its upper reservoir level limits, which is the case for the 92 % percentiles based on historical reservoir levels.

Øvre Røssåga power plant consists of three identical units with a Francis turbine. The plant is designed to handle 160 MW and the connected units have a best point efficiency at 89.74 % and an energy equivalent of 0.3 kWh/m3. The annual production is about 830 GWh at an average utilization time of 5189 hours.

The outlet from Øvre Røssåga, and the by-pass from Røssvatn, leads to Fallfors reservoir. Fallfors is a small reservoir with a total capacity about 11 GWh. Combined with several inflow possibilities, the degree of regulation becomes very low (near zero).

Due to regulatory restriction demanding a minimum water flow at 15 m^3/s downstream of Nedre Røssåga, this amount is continuously supplied from Fallfors. Either thorough Nedre Røssåga, or by-passed over a 20km long distance with a time delay of 3-5 hours.

Nedre Røssåga is a relatively large hydropower plant with six units and an average best point at 87.90 %. The energy equivalent is 0.57 kWh/m^3 and the plant is designed with a maximum production capacity at 259 MW. Its annual production amounts to 1698 GWh at a utilization time of 6790 hours.

The water balance in this system can be illustrated with the following example: Assume no inflow to Fallfors and maximum production at Nedre Røssåga (~250 MW). This scenario gives Øvre Røssåga an implicit average production at 132 MW, which is not enough to reach the best point but still close.

Technical overview

The reservoirs has the following specifications listed in Table 21. The degree of regulation is relatively robust for the largest reservoirs.

Table 21 - Technical data for the reservoirs in Røssåga river system

Reservoir	Degree of regulation	GWh	LRV	HRV
Bleikvatn	1.4	218.3	386	407.5
Røssvatn	0.7	2015.8	372.2	383.15
Fallfors	<< 0,01	10.8	244.5	247.9

The specifications for the stations, and their respective units are listed in Table 22. Every unit consists of a Francis turbine, and the head is normal value:

Table 22 - Technical data regarding generating units in Røssåga river system

Station	Unit	P_max [MW]	P_min [MW]	Head [m]	Q_max [m3/s]	e [kWh/m3]	n
Øvre Røssåga	Øvre Røssåga G1	53.3	32	123.9	50	0.303	0.89
Øvre Røssåga	Øvre Røssåga G2	53.3	32	123.9	50	0.303	0.89
Øvre Røssåga	Øvre Røssåga G3	53.3	32	123.9	50	0.303	0.89
Nedre Røssåga	Nedre Røssåga G1	42	20	236	20	0.57	0.88
Nedre Røssåga	Nedre Røssåga G2	42	20	236	20	0.57	0.88
Nedre Røssåga	Nedre Røssåga G3	42	20	236	20	0.57	0.88
Nedre Røssåga	Nedre Røssåga G4	42	20	236	20	0.57	0.88
Nedre Røssåga	Nedre Røssåga G5	48	38	242	21.4	0.57	0.86
Nedre Røssåga	Nedre Røssåga G6	43	38	242	21.4	0.57	0.86

Reservoir capacity and inflow

Figure 48 depicts the reservoir fillings in per cent of total capacity (left graph), as well as inflow in MWh to the respective reservoirs (right graph). Røssvatn is by far the largest reservoir in the river system but it has to be managed correct due to its degree of regulation. One can observe the seasonal characteristic where the reservoir level is decreased until mid-May, when the inflow is coming as snow melting and some precipitation as illustrated in figure 36. Fallfors is kept constant at 80 % filling, but it were tapped during September to November due to maintenance. Bleikvatn has more capacity than yearly inflow, so it can be used to supply Bleikvatn during the winter period.

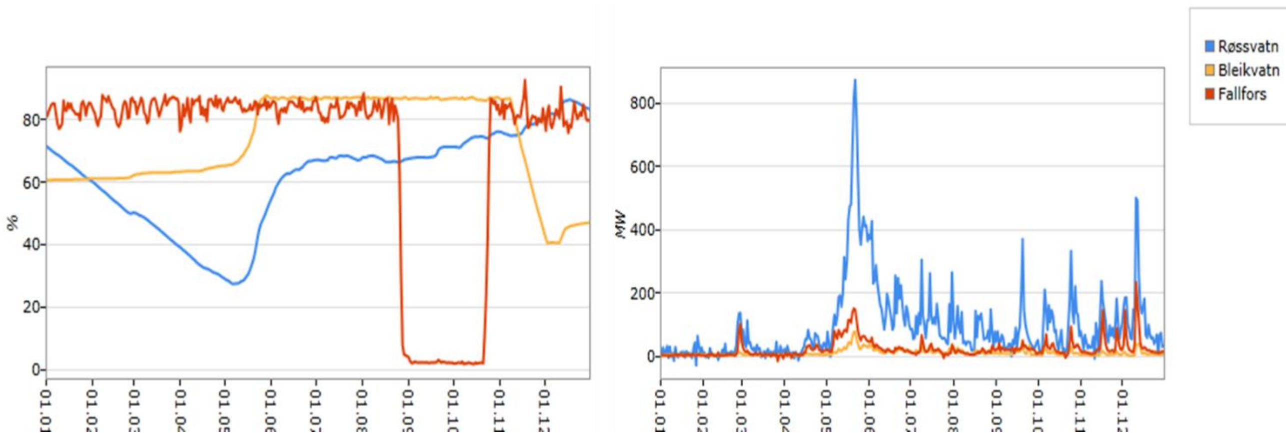

Figure 48 - Reservoir levels (left plot) and inflow (right plot) at Røssåga river system during 2013

The total reservoir capacity seen from each station is illustrated in Figure 49. It is a clear correlation with the reservoir level at Røssvatn in Figure 48. The energy equivalent is greater at Nedre Røssåga and the production at this station will always be prioritized. The seasonal coupling from winter to summer may be an interesting scenario for the calculations, where the stations are running near their capacities.

Figure 49 - Total reservoir capacity seen from the stations in Røssåga river system during 2013

7.3 VIK

Vik river system is located south of Sognefjorden in price area NO5, at 330 to 1130 masl. The topology of the river system is depicted in Figure 50. It is a relatively small system with three power plants, five units, and a total installed capacity of 183.5 MW. However, it consists of nine reservoirs and a more complex water management both with respect to time delays and possible water balancing, compared with Leirdøla and Røssåga. The total reservoir capacity is 413 GWh and the yearly production at Vik amounts to 979 GWh on average.

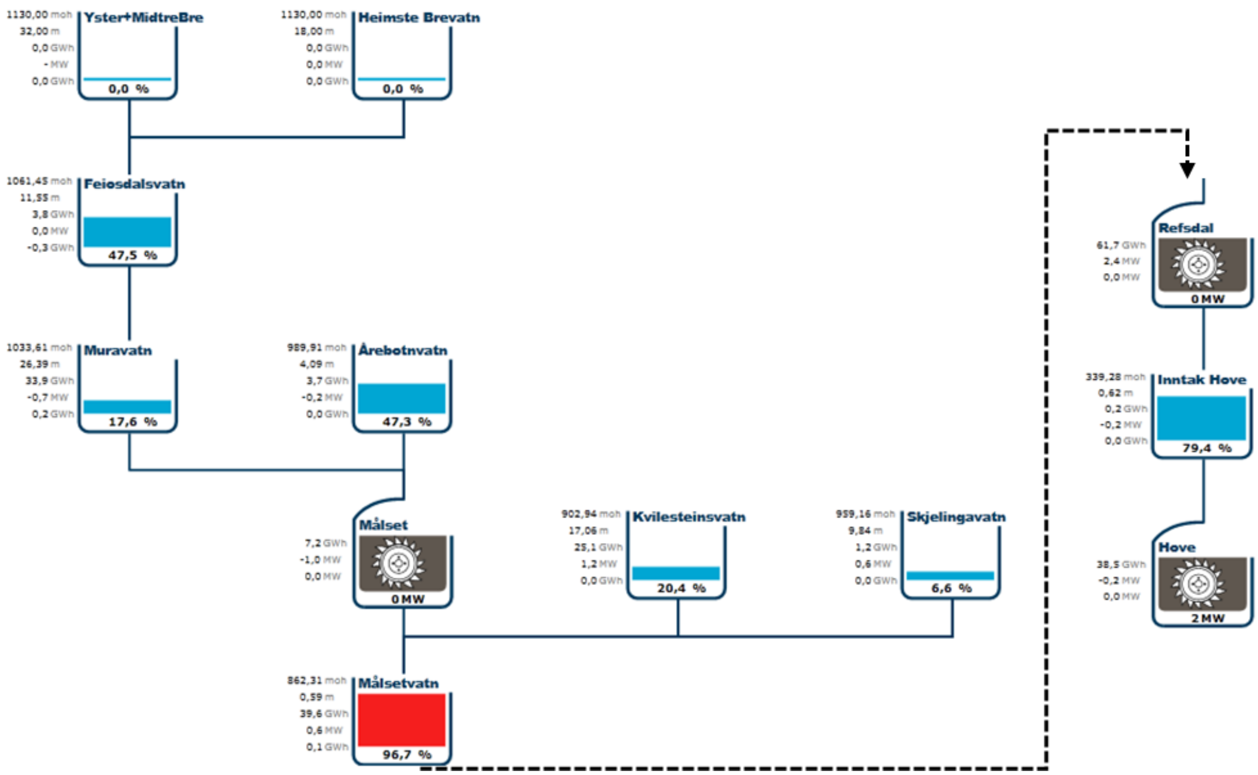

Figure 50 - Topology of Vik river system

The reservoirs in this system does often reach their limits based on historical average reservoir levels. The two largest reservoirs, Muravatn and Kvilesteinsvatn, has a capacity of respectively 193.5 GWh and 122.6 GWh. Both with a regulation degree about 0.50. On the other hand, we got Årebotnvatn and "Inntak Hove" as the two smallest reservoirs with 7.3 and 0.2 GWh capacity, and a degree of regulation at 0.15 and near zero.

Målset power plant has two intakes from separate reservoirs at different head, hence different generation capacity, P_{max}, where an intake from Årebotnvatn only gives P_{max} = 12 MW (versus 23 MW). Since the latter mentioned reservoir has a poor degree of regulation it can often result in forced production at lowest P_{max} during the summer to avoid spillage.

The next plant in the system, Refsdal, is supplied through Målsetvatn, which also have a poor degree of regulation. The production at Refsdal gets restricted by the local inflow to “Inntak Hove” which again supply the last hydro power plant, Hove.

Hove has a relatively high utilization time above 6000 hours per year. The possibility for bottlenecks at the station puts pressure at Hove. During summer the plant can typically be forced into production to avoid spillage upstream in the system.

Technical overview

Reservoir specifications is listed in Table 23:

Table 23 - Technical data regarding the most important reservoirs in Vik river system

Reservoir	Degree of regulation	GWh	LRV	HRV
Muravatn	0.52	193.5	1020	1060
Årebotnvatn	0.15	7.3	984.6	994
Kvilesteinsvatn	0.54	122.6	895	920
Skjellingavatn	0.25	18.3	958	969
Målsetvatn	0.05	40.9	834	862.9
Inntak Hove	<< 0,01	0.2	335	339.5

Specifications for the stations and their respective units are listed in Table 24. Each unit consists of a Francis turbine, and the calculated head is a normal value:

Table 24 - Technical data regarding generating units in Vik river system

Station	Unit	P_max [MW]	P_min [MW]	Head [m]	Q_max [m3/s]	e [kWh/m3]	n
Målset	Målset	23.5	13	163.4	14.3	0.424	0.952242
Refsdal	Refsdal G1	46	23	503.5	10.7	1.243	0.905952
Refsdal	Refsdal G2	46	23	503.5	10.7	1.243	0.905952
Hove	Hove G1	34	15	312.1	12.6	0.773	0.908907
Hove	Hove G2	34	15	312.1	12.6	0.773	0.908907

Reservoir capacity and inflow

The reservoir capacity and inflow seen from the power stations in Vik is depicted by the left plot in Figure 51. The inflow hits the Vik earlier than at Røssåga, and the total reservoir capacity is nearly tapped already in the beginning of April. The capacity is kept low until the inflow kicks in the beginning of May.

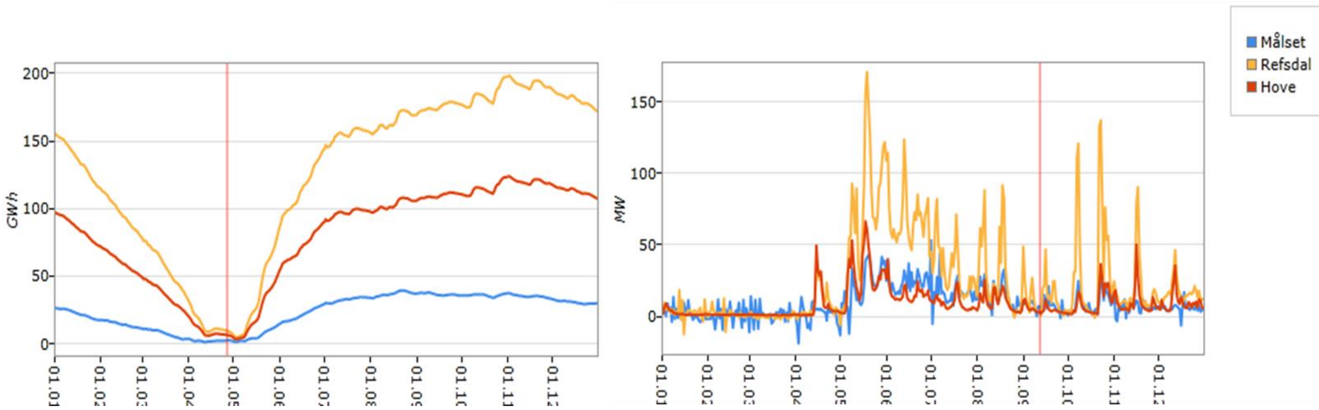

Figure 51 - Total reservoir capacity (left plot) and inflow (right plot) seen from the power stations in Vik river system during 2013

The seasonal couplings are again interesting optimization cases, especially with respect to water values. The water values are rapidly changing (relatively) for less flexible reservoirs in the river system, and since SHOP uses independent expected water values (about one week ahead) minor changes can have some impact on the water management and income. A method to account for uncertainty in the future water value will be presented.

8 CASE STUDY

A case study is assessed with different river systems, as well as for price areas. The idea with the case study is to use the market observations in Section 6, and pinpoint eventual connections with the theoretical improvement potential that is being pursued. This approach were considered as a good alternative due to lack of possibility to use scripts running SHOP optimizations, as discussed in Section 5.4.

An overview of the price areas can be found in Appendix III, listed with corresponding river systems. Three individual river systems are selected for the case study. The selection of these river systems are based on creating a diversity in total reservoir capacity, production capacity, and system complexity. The selected river systems are:

- Leirdøla; capacity 184 GWh, and degree of regulation at 0.4
- Vik; capacity 413 GWh, and a degree of regulation between 0 and 0.5
- Røssåga; capacity 2245 GWh, and a degree of regulation between 0.7 and 1.4

A presentation of the river systems can be found in Section 3.5.

8.1 LOW PRICE VOLATILITY

If the intraday price volatility during 2013 is sorted in ascending order, from minimum to maximum, one would notice that nearly top 30 days are all red-days, such as Sundays, or holidays. The price forecasts at these days are "out of date" for day-ahead bidding, and one would therefore have to use the newest forecast available. For example if the chosen date is a Sunday, one would need to use price forecasts that were calculated at Friday (given that Friday not is a red-day, as well). However, to diversify the low volatility analysis, the following cases are chosen:

1. High average price at 31st of March, 2013
    a. Within a period affected by energy- and effect deficit in the Nordic market
2. Low average price at 3rd of November, 2013
    a. Short-term effect surplus causing intraday peak-shaving

High price level (31. March)

Several days at the end of March resulted in a very low standard deviation. Sunday 31st of March is chosen as the scenario with a low price volatility, and a high average system price amounting to 46.40 EUR/MWh. Another interesting view of this case is that both Thursday and Friday are holidays, hence the latest available price forecasts can be as old as from Wednesday. Figure 52 shows the system price development around the chosen date.

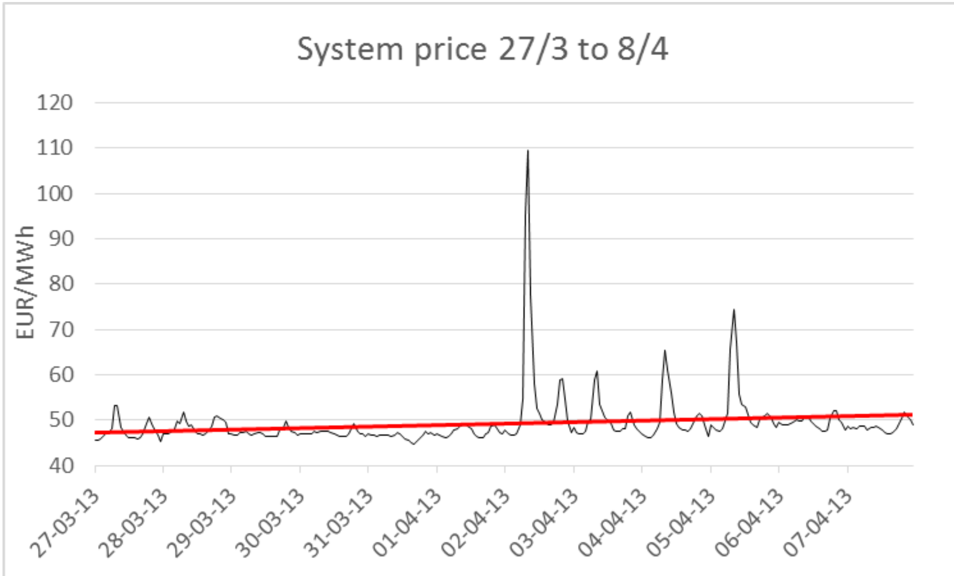

Figure 52 - System price from Wednesday 27/3 to Monday 8/4

The price development in Figure 52 looks like a typical example where the market is in energy deficit, in addition to effect deficit during peak hours, according to the characteristics given in Section 6.5. The red trend-line shows an increasing price over the period, which may be a result of higher sell bids from the hydropower producers to reduce production from the nearly emptied reservoirs. Figure 53 shows that the wind production at Nord Pool was relatively low and stable during the period. The imports to Norway were also relatively low.

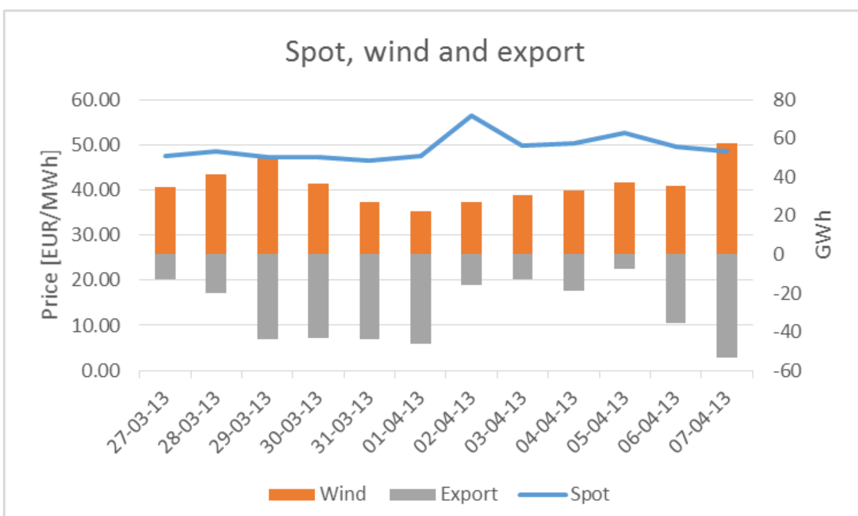

Figure 53 -System price (NO), wind production (NP), and exports (NO) from 27/3 to 7/4

The price scenarios (given in Table 1) for Sunday 31/3 are shown in Figure 54. S6 were calculated at Friday, S7 at Thursday, and S2-S5 at Wednesday. The naïve scenario, S8, seems to have been a better guidance for the spot price, than the rest of the forecasts. The price level turned out to be higher than expected during the period between the calculations of forecasts, till the price clearing at Sunday. This indicates that the price forecasts could have used too low water values, or that the expected inflow was postponed to a later point in time, thus providing scarce water resources.

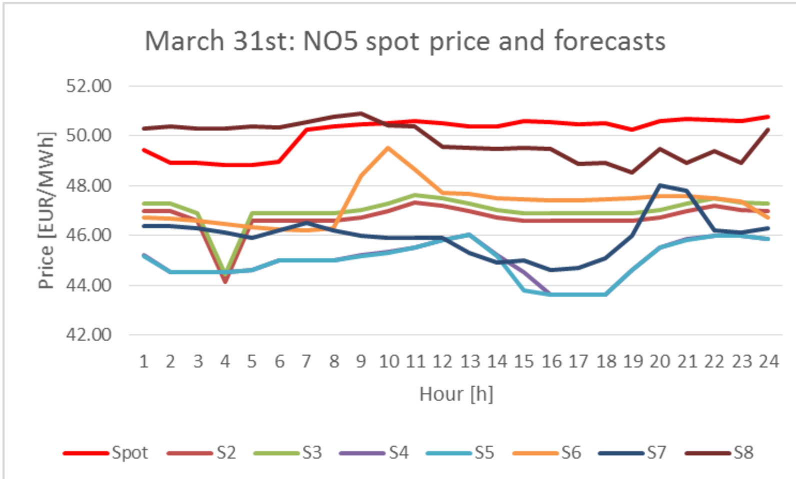

Figure 54 - NO5 spot price, and price forecast scenarios for Sunday, March 31st

The optimizations with SHOP are executed for Saturday March 30th, analogue to bidding in the spot market for March 31st. Two additional price scenarios are included, one at a very low price, and one at a very high price. These additional price scenarios are included to control possible forced generation, as well as maximum generation, respectively.

Leirdøla

The reservoir level at Leidøla is nearly empty (Figure 46) with minor short term inflow expectations, hence the high water value at 60 EUR/MWh. None of the price scenarios exceeds this price level, and the price forecasts are therefore irrelevant for the outcome of any price independent bids. However, there is some minor production beyond March 31st. The optimization results from SHOP are not included since there are no particularly interesting results. Each scenario gives the same decisions for the following day, and the objective function (income) amounts to 13,613 EUR at all scenarios.

The low-price scenario did not cause any forced production, which is reasonable in this case where there is only one station. The high price scenario sells all the available water during the two last hours in the optimization period, despite the high water value and obviously low reservoir level.

The water management in this case is irrelevant with respect to income, and therefore is the theoretical improvement potential 0 EUR. The reservoir level stays about empty for almost one month ahead of this date, with negligible inflow. Hence, the conclusion is that none of the price forecasts has any value.

Vik

The reservoir levels at Vik are very low (Figure 51) at this point of time, but not all of them are empty. The water values should be robust, meaning that the LT model has better guiding, compared with earlier in the March month when the reservoir levels were decreasing rapidly. The WV's varies in the interval 45-60 EUR/MWh from reservoir to reservoir. There are also some expected, minor inflow ahead in the start of April.

Note that the stations has the capacity to produce throughout the period, except for Målset, which is indicated by the high-price scenario. Both Refsdal and Hove are being exposed to forced production, and since there is no production from Målset it has to be one of the reservoirs downstream with a poor degree of regulation being tapped to avoid spillage. The scheduled generation at Hove is illustrated in Figure 55.

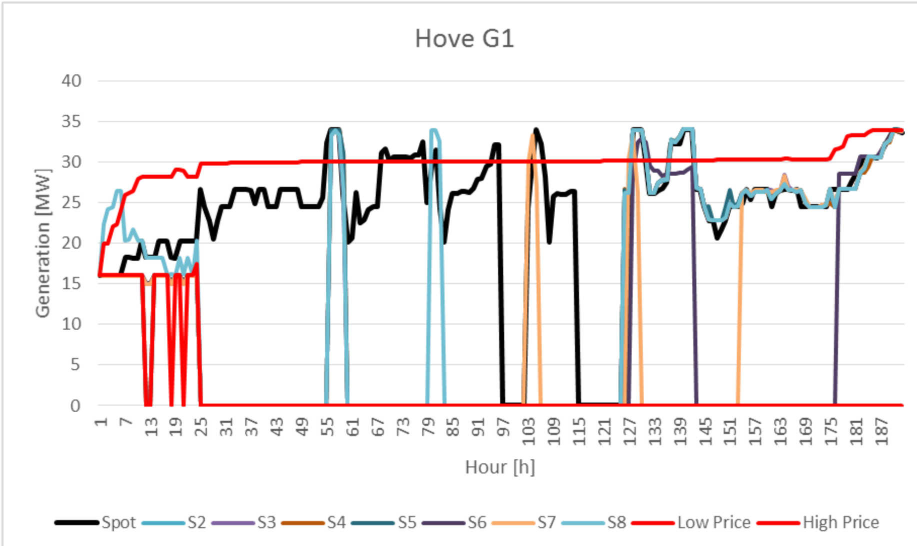

Figure 55 - Scheduled generation at Hove with respect to different price scenarios.

The upper- and lower red plot in Figure 55 represents the high- and low price scenario, respectively. These lines indicates the maximum and minimum generation for a given system, with respect to its physical restrictions. It is important to remember that the LT models not are as detailed as SHOP, thus the LT model may have other assumptions for the max/min generation, which again could influence the price forecasts. In situations like this, where the minimum generation may not be very intuitive (or logic) it may be a good idea to run optimizations in SHOP prior to creating a price forecast. The production planner can here assume that the WV's from the LT models are too low, and therefore expect a future increasing price trend as shown in Figure 52.

Vik is naturally not a large contributor to variations in the spot price, but the statement made in the previous paragraph is only to make a point. This phenomena could yield for other river systems as well, with the potential of forced production, hence the aggregated impact could affect the spot price.

The other price scenarios is scheduled for various production, and one can therefore expect potential improvements of the respective price forecasts. The comparing optimization with SHOP is illustrated in Table 25.

Table 25 - Comparison of the price scenarios used for Vik river system Sunday, March 31st

Scenario	Income	Potential improvement	Sales	Startup costs	ΔStartup	Reservoir value	ΔReservoir	Penalty
S1	2 418 509	0	810 714	4 700	0	1 612 495	0	11 480
S2	2 417 571	938	793 344	5 060	360	1 629 287	16 791	11 480
S3	2 417 612	897	793 547	5 060	360	1 629 125	16 630	11 480
S4	2 417 333	1 176	796 532	4 960	260	1 625 761	13 266	11 767
S5	2 417 381	1 129	795 183	4 960	260	1 627 158	14 662	11 767
S6	2 417 840	669	789 331	5 060	360	1 633 569	21 073	11 767
S7	2 417 667	842	803 980	4 240	-460	1 617 927	5 432	11 480
S8	2 417 952	557	807 902	5 060	360	1 615 109	2 614	11 480
Low price	2 415 845	2 664	789 411	6 860	2 160	1 633 294	20 798	11 772
High price	2 411 245	7 264	894 866	4 230	-470	1 520 609	-91 887	11 480

Note that there is an occurrence of penalty in the rightmost column. The penalty costs are nearly identical in each scenario, but to compensate for the penalty costs in the income, hence also the potential improvements, one should subtract for the same penalty-amount that the penalty exceeds the spot penalty. For example S4 has a penalty amounting to 11,767 EUR, which exceeds the spot-penalty (S1) with 287 EUR, thus should the potential improvement for S4 be 1,176 – 287 = 889 EUR. That is the reason why the penalty column is included in cases like this.

Anyway, the potential improvements are limited, and the naïve price scenario was the best forecast, as expected according to the price profiles in Figure 54. Further does the "High price"-scenario imply that a price forecast not can exceed a maximal theoretical improvement potential amounting to 7,264 EUR. In other words, the low- and high price scenarios defines the feasible potential improvement space for a price forecast used for price independent day-ahead bidding (as indicated by the red lines in Figure 55).

Røssåga

Røssåga is as mentioned earlier a quite flexible river system, with a robust degree of regulation. The reservoir levels are relatively high for the period (Figure 48), and the largest one (Røssvatn) is still being tapped. The WV's reflect the hydrological balance, and they are respectively 41.1 EUR/MWh and 29.1 EUR/MWh for Røssvatn and Fallfoss. The WV guiding from the LT should be ok, since the reservoirs are so large and requires huge amount of generation to affect the end-reservoir levels (the base point for the independent WV's). Hence, one can assume that no strategy involving WV-adjustments will hone the income significantly.

The low-price scenario results in forced production at Nedre Røssåga station, for unit G1 and G3. Recall that Fallfors, the first reservoir upstream, has a constant discharge and thus giving minor forced production at the lower station. Besides that, there are no further interesting observations at Nedre Røssåga since all of the price scenarios schedules for full production due to the low water value, and the tapping of Røssvatn.

Øvre Røssåga station has scheduled for various generation at the respective units. The low-price scenario gives zero production as lower limit. On the other hand, does the high-price scenario naturally result in maximum generation. The production at unit G1 and G3 are depicted in Figure 56.

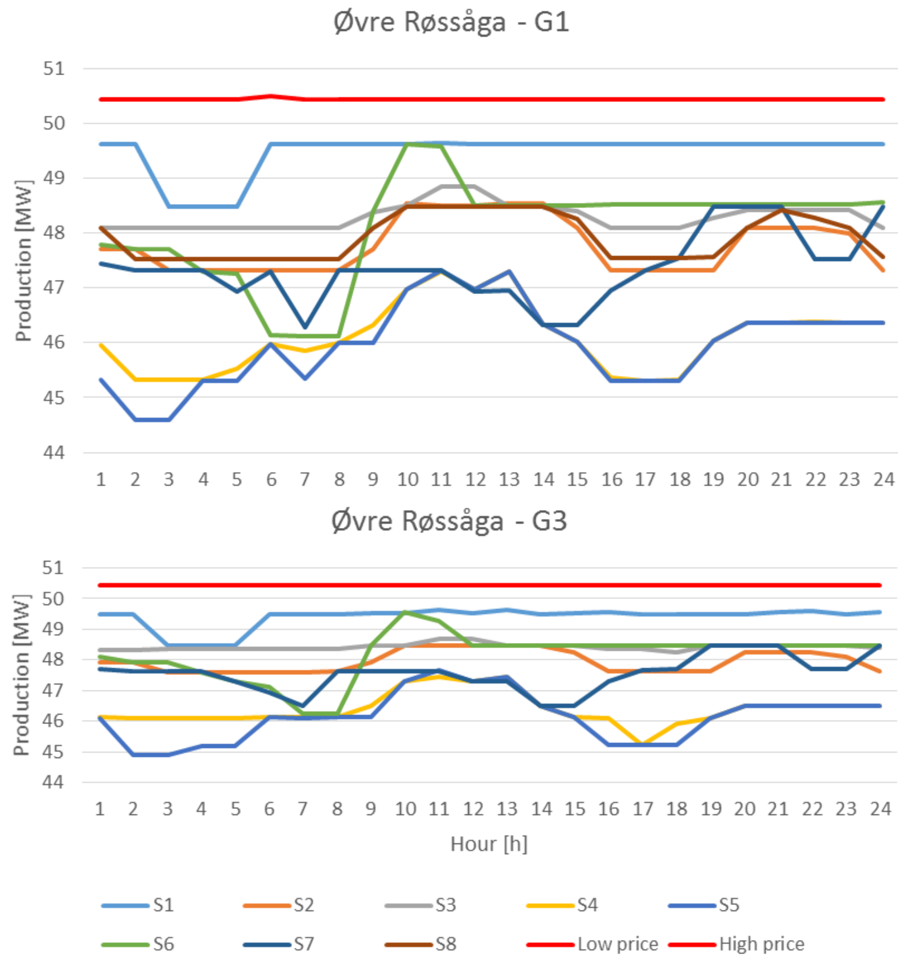

Figure 56 - Scheduled production at Øvre Røssåga, unit G1 and G3, March 31st

The units connected to the water tunnel into Øvre Røssåga is divided into two penstocks, hence the prioritization of production at G1, followed by G3 and G2. A MC plot would give a good illustration of this relationship, but this is not included due to sensitive information.

The results from the comparative optimization is listed in Table 26. The potential improvements for the price forecasts are small, but the potential costs of using a poor price forecast is considerable as seen by the low- and high price scenario. The theoretical improvement amounts to 677 EUR on average for the price forecasts S1 – S8.

Table 26 – Comparison of the price forecasts used for Røssåga river system, March 31st

Scenario	Income	Potential improvement	Sale	Startup costs	Reservoir value	ΔReservoir	Penalty
S1	30,865,981	0	3,768,816	3,860	27,101,025	0	0
S2	30,866,819	838	3,774,169	3,860	27,096,510	-4,515	0
S3	30,865,932	49	3,767,076	3,860	27,102,716	1,691	0
S4	30,867,736	1,755	3,780,470	4,350	27,091,616	-9,409	0
S5	30,867,920	1,939	3,780,913	4,350	27,091,357	-9,668	0
S6	30,865,956	26	3,767,844	3,860	27,101,972	947	0
S7	30,866,763	782	3,773,382	3,860	27,097,241	-3,784	0
S8	30,865,957	25	3,770,467	3,860	27,099,350	-1,675	0
Low price	30,753,242	112,739	3,374,833	4,800	27,383,210	282,184	0
High price	30,829,928	36,053	3,771,316	4,350	27,062,962	-38,063	0

Low Price Level (3. November)

Sunday, November the 3rd is chosen as the low price-level case. November starts with a relatively low price volatility, increasing throughout the month, as well as the daily system price level starting at 32.92 EUR/MWh on November 3rd, peaking at 41.68 EUR/MWh in the end of the month. The latest available price forecasts are calculated at Friday, and the LTM has is assumed to follow a robust guiding with respect to future reservoir levels, and water values. The system price around this date is depicted in Figure 57.

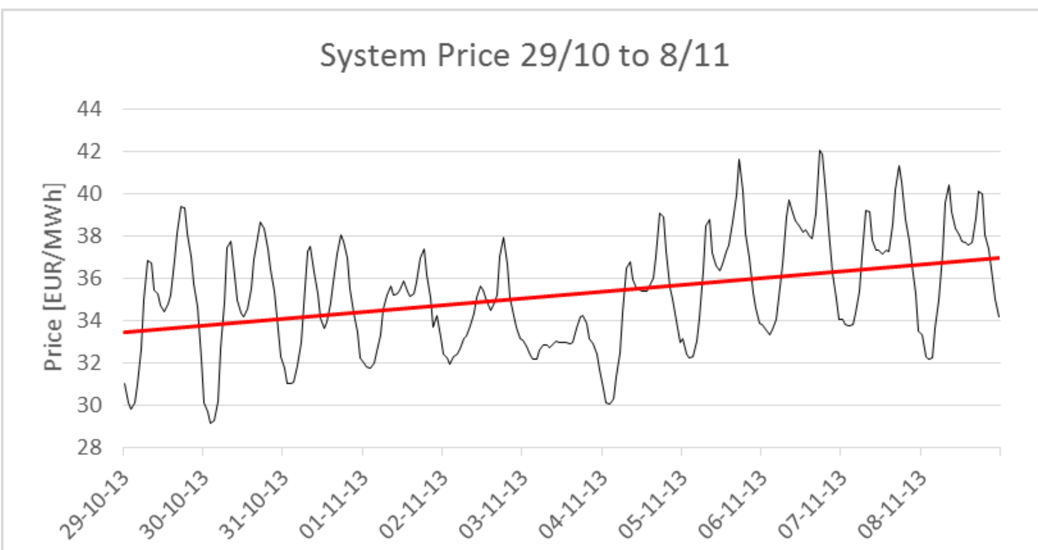

Figure 57 - System price development around November 3rd

The price level at November 3rd seems to be kept down for some reason, and the price dips during night to the following day. In combination with lower consumption at Sunday, than for weekdays, the wind production at Nord Pool achieves a short-term peak amounting to 120 GWh for the Sunday being analyzed, which amounts to 70 % of the maximum wind power capacity. This observation is illustrated in Figure 58, where also the net export from Norway is included in the same figure.

As the wind production peaks, Norway becomes a net importer. The low MC wind production is most likely being imported from DK1 and SE3, and it will most likely also affect the spot price. All three observations are depicted in Figure 58. The market situation at Sunday, November 3rd, could remind us of an energy-/effect surplus but in that case a relatively short-term effect.

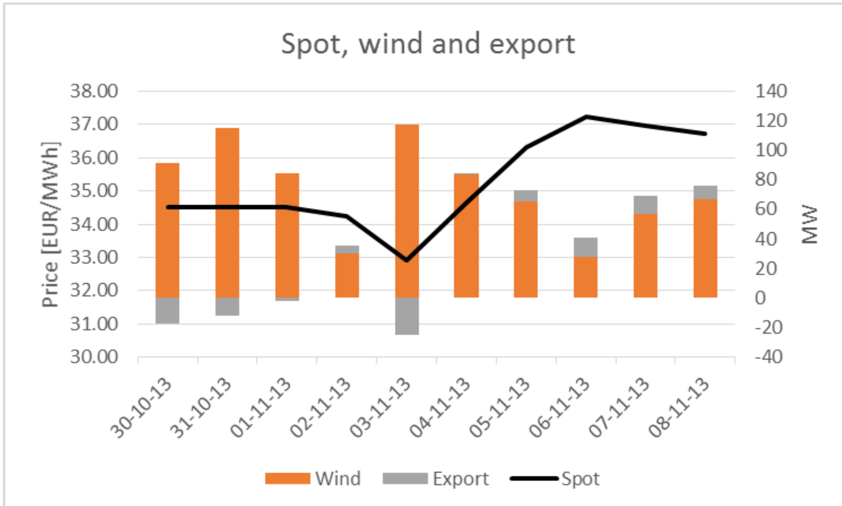

Figure 58 - Daily spot price, wind production (NP) and export (NO) around November 3rd

Figure 59 illustrates the spot price in NO5, as well as the price forecasts, for November 3rd. Assuming that the consumption were relatively predictable, the price forecasts may have accounted for more wind production than actual, as well as higher temperatures, hence a minor price lift during the night.

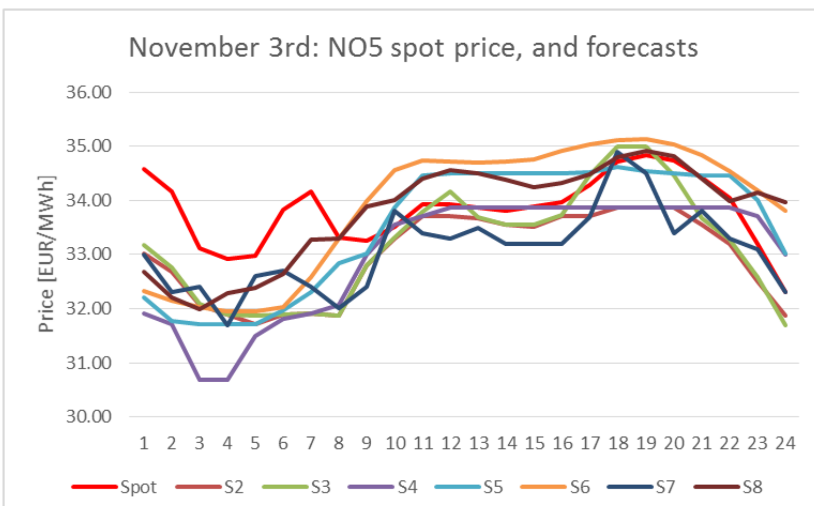

Figure 59 - NO5 spot price, and forecasts for November 3rd

Leirdøla

The reservoir level at Leirdøla is at its yearly maximum, and due to less inflow ahead the levels are expected to drop as production will be scheduled. The WV amounts to 36.5 EUR/MWh, which is above the spot price in NO5 for November 3rd. None of the price scenarios will schedule for production at the station for the

Sunday, except the very-high-price scenario who schedules for max generation at 125 MW during the whole day.

The results does not show any interesting findings as the theoretical improvement amounts to 0 EUR on average. As long as the price forecasts are lower than the WV, they will all be irrelevant for the water management in the day-ahead market. Exceeding the WV will result in scheduled generation, and therefore the corresponding price series would have potential improvements.

The WV strategy remains as it is, as the guiding from LTM seems to be robust. Given that we are in an energy-/effect surplus situation, an interesting test could be to use a weighted average of MC, as WV (to account for milder temperatures than assumed, thus also short-term inflow).

Vik

Vik has peaking reservoir levels, as well as moderate amounts of inflow during November. This could indicate milder temperatures than expected. The WV's varies around 31 – 33 EUR/MWh, which seems to reflect the hydrological balance good (ref. iso-price water value curves). Vik will eventually schedule for production as the price scenarios are above the WV's.

The optimizations with SHOP shows that there is forced production at all stations, except Målset which is located highest upstream in the river system. A graphical illustration of the scheduled production at November 3rd at Hove G1 is depicted in figure 47. The forced production is a result of avoiding spillage upstream of the respective stations, which can imply that the WV's from the LTM potentially could be too high. Meaning that an alternative strategy could be to lower the WV's in SHOP, due to short-term inflow and potential inconsistence with the WV coupling. A method for doing this, is to use MC with respect to a multi-scenario optimization as WV.

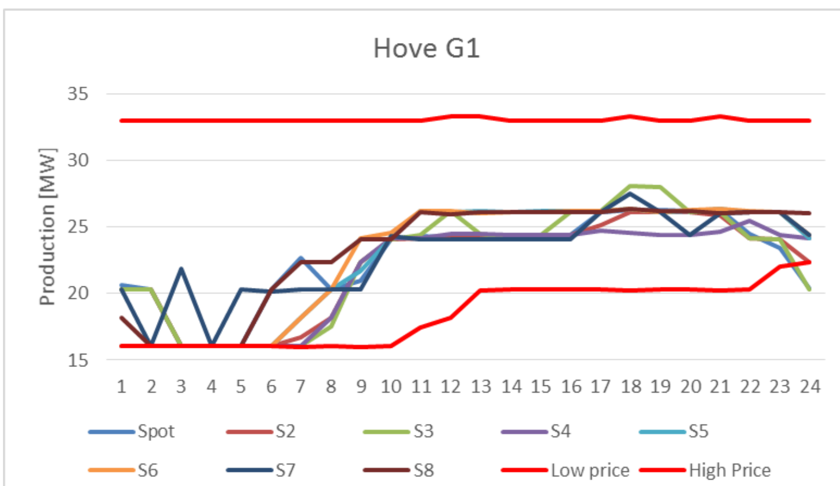

Figure 60 - Scheduled production at Hove G1 in Vik river system, November 3rd

The lower red line in Figure 60 represents the minimum production at the station. Since the production upstream is increasing throughout the day, the lower limit increases as well since the water should be utilized, and not by-passed. The economic value of the price forecasts is therefore dependent on how close they schedule with respect to optimal production. The comparative optimization with SHOP is listed in Table 27.

Table 27 – Comparative from the price forecasts used for Vik river system, November 3rd

Scenario	Income	Potential improvement	Sale	Startup costs	ΔStartup	Reservoir value	ΔReservoir	Penalty
S1	8 336 321	0	725 737	2 090	0	7 612 675	0	2 850
S2	8 336 227	95	721 194	2 090	0	7 617 123	4 448	2 850
S3	8 336 157	164	723 159	2 090	0	7 615 088	2 413	2 850
S4	8 336 133	189	722 028	2 090	0	7 616 195	3 520	2 850
S5	8 336 212	109	725 944	2 090	0	7 612 358	-317	2 850
S6	8 336 214	108	726 748	2 090	0	7 611 556	-1 119	2 850
S7	8 336 094	227	722 074	2 090	0	7 616 110	3 436	2 850
S8	8 336 195	126	727 426	2 090	0	7 610 859	-1 815	2 850
Low price	8 334 120	2 202	695 640	3 830	1 740	7 642 310	29 635	2 850
High price	8 333 231	3 090	778 475	2 090	0	7 556 846	-55 829	2 850

The theoretical improvement potential for Vik in this case, is 127 EUR. Compared with 776 EUR in the low volatility, high price case.

Røssåga

Røssåga has nearly full reservoirs, as well. There is a significant amount of inflow ahead, and the WV's are 30 EUR/MWh and 16.1 EUR/MWh at Røssvatn and Fallfoss, respectively. Fallfoss is therefore expected to schedule maximum production at all hours, according to the level of the price scenarios, except the low-price scenario which obviously will schedule zero (or forced) production.

The results imply forced production at Nedre Røssåga station for the units G1 and G3. There are also situations where the high-price scenario gives slightly lower generation than the other price forecasts, due to the efficiency curve and best point operation. Both of these observations are illustrated in Figure 61. The left graphing in the figure shows that there is various scheduled production, thus one can expect minor potential improvements of the price forecasts. The low-price scenario is scheduled for zero production, and therefore not visible in the left plot.

The right plot in Figure 61 shows a lower red line which indicates that there is forced production around 37 MW, not matter what the price forecast is. The upper red line is the high-price scenario, and the scheduled production for the normal price scenarios is above this upper limit, which is not as intuitive at first sight.

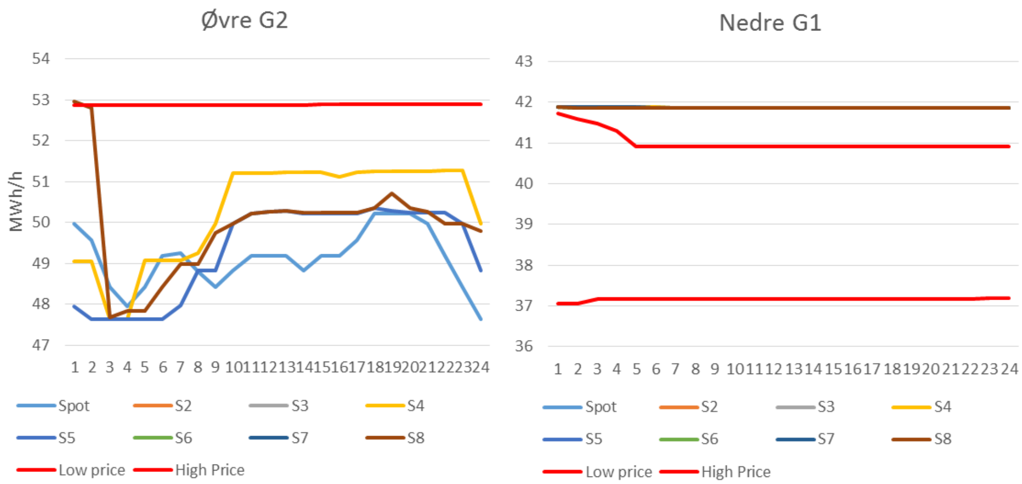

Figure 61 - Scheduled generation at Øvre Røssåga G2, and Nedre Røssåga G1, November 3rd

The results from the comparative optimization is listed in Table 28. The penalty were zero for all scenarios, and not included in the table. The price forecasts gave relatively equal income, compared with the spot price. The average improvement potential is 109 EUR, compared with 677 EUR in the high price case. This is a result of the relatively high price level compared with the WV's, so the scheduled generation became nearly identical for each scenario.

Table 28 – Comparative results for the price forecasts used for Røssåga, November 3rd

Scenario	Income	Potential improvement	Sale	Startup costs	ΔStartup	Reservoir value	ΔReservoir
S1	37 692 382	0	2 488 635	3 370	0	35 207 117	0
S2	37 692 377	4	2 488 115	3 370	0	35 207 633	516
S3	37 692 375	6	2 488 244	3 370	0	35 207 501	384
S4	37 692 267	115	2 489 300	3 370	0	35 206 337	-780
S5	37 692 356	26	2 488 881	3 370	0	35 206 845	-272
S6	37 692 022	360	2 486 834	3 370	0	35 208 558	1 441
S7	37 692 372	10	2 487 971	3 370	0	35 207 771	654
S8	37 692 029	353	2 486 816	3 370	0	35 208 583	1 466
Low price	37 614 754	77 627	2 252 759	4 310	940	35 366 306	159 189
High price	37 671 511	20 871	2 470 649	2 880	-490	35 203 742	-3 375

8.2 HIGH PRICE VOLATILITY

The price volatility is particularly high during the last half of June. The price development during 21-24th of June has standard deviations spanning from 13 – 44 %, characterized by negative price sparks, and low prices. June 23rd is chosen as the first, of two, cases with high volatility and a low average price at 19.18 EUR/MWh. The second case is 21st of March with an average price amounting to 56.36 EUR/MWh, thus representing high volatility and a relatively high price level.

Low price level (June 23rd)

The system price around June 23rd is shown in Figure 62. The price development shows no clear trend according to this data sample, which is indicated by the red line in the figure. This is a typical period with medium-/low reservoir levels and the ability to store future inflow. The price pattern between 22. - 23. June could remind of effect deficit; low price at night and high during the day. But the prices during peak hours is not high enough to qualify for that hypothesis.

Assuming that the temperature were relatively stable and that there was no major inflow, it has to be a short-term, positive supply shift at low MC that caused the price drop. Hence, wind production may be a natural explanation factor for this supply shift.

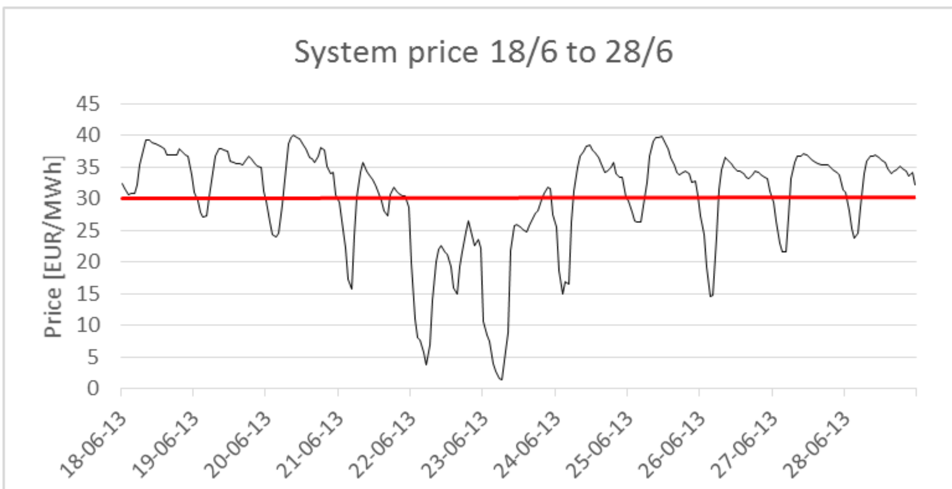

Figure 62 - System price around June 23rd

Figure 63 depicts the daily system price, wind production at Nord Pool, and net exports from Norway. The weekend does usually have lower demand, and in addition to the significant increase in wind power generation, the weekend price drops becomes revealed. The net export, during the same days, confirms that the MC from the wind generation gives incentives for importing electricity to Norway.

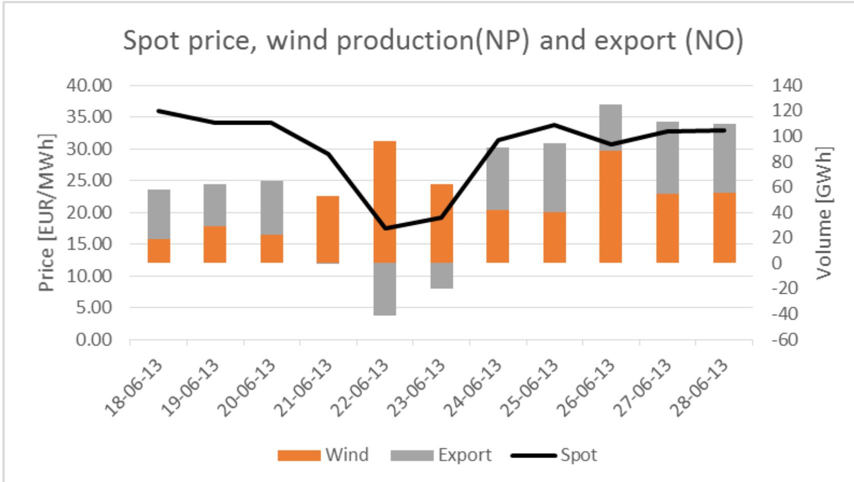

Figure 63 - Daily system price (NO), wind production (NP), and exports (NO) around June 23rd

The price scenarios used for the SHOP optimizations are illustrated in Figure 64. The spot price (red line) has a lower price profile than the other scenarios during the night. The naïve scenario, which represents the spot price the previous day, does also have the same profile at a lower level than the rest of the scenarios. This might imply that the price forecasts predicted less wind production than the actual quantity.

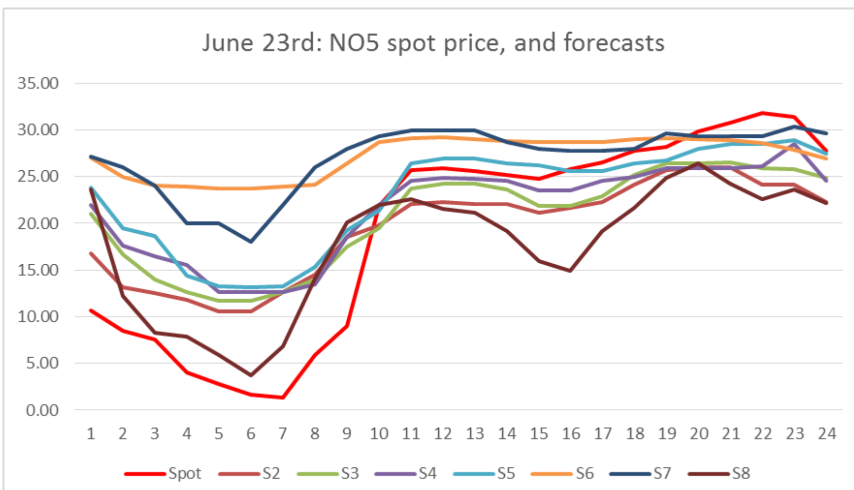

Figure 64 - NO5 spot price, and forecasts for June 23rd

Leirdøla

The reservoir level at Leirdøla is rapidly changing, and it might therefore be an interesting seasonal-coupling-example regarding the use of MC as WV. The reservoir is filled with one third, and the inflow is increasing throughout the end of July. An aggregated effect of this situation would most likely cause energy-/effect surplus, especially if the inflow is greater than the production capacity, and the consumption is low. Indications of this hypothesis will be pursued.

The WV amounts to 30.15 EUR/MWh, and the spot price is the only price series exceeding this value during the last few hours of Sunday 23rd of June. Hence, the scheduled production for the spot-scenario becomes the potential improvement for the price forecasts, which only amounts to 115 EUR due to start-up costs for the few hours. The maximum production limit is naturally 125 MWh/h, since the reservoir capacity and inflow is sufficient enough.

The inflow for this case is larger than the production capacity. 42 m^3/s inflow on average, versus 29 m^3/s capacity.

Vik

The reservoir levels for Vik is following a steep increasing curve, and in the same way as for Leirdøla, this is a good situation for analysing the filling-season with rapidly changing reservoir levels. The inflows are high, and in a slowly falling trend two months ahead. Thus, the water value coupling with the LTM may be a potentially weak factor for the short-term water management.

Both Refsdal and Hove are exposed to forced production, while the scheduled production at Målset is zero, except for the two first hours in the high-price scenario. The minimum- and maximum limits at Hove station are really tight due to the high spillage risk, as shown by Figure 65.

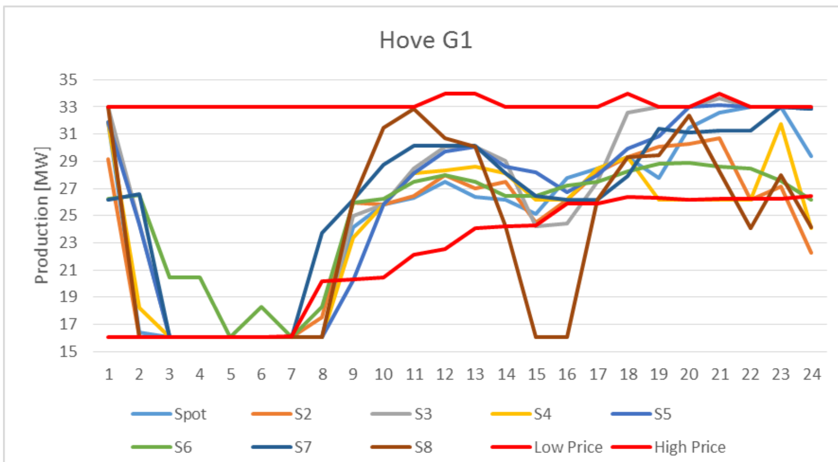

Figure 65 - Scheduled production for the unit Hove G1 during June 23rd at Vik river system

Results from the comparative optimization is listed in Table 29. The importance of a good price forecast is potentially large for the high-price scenario. But the question is; how robust is the WV guiding from the LTM? In this case there are coincidences of forced supply at very low prices, which should give a negative price-shift as indicated in Figure 64 (given that this supply-shift not accounted for in the LTM). The future WV's could therefore be lowered as a possible strategy for bidding in the day-ahead market.

Table 29 - Comparative results from Vik river system, 23rd June

Scenario	Income	Potential improvement	Sale	Startup costs	ΔStartup	Reservoir value	ΔReservoir	Penalty
S1	6,604,863	0	111,060	5,170	0	6,498,973	0	17,301
S2	6,604,657	206	110,664	5,170	0	6,499,163	190	17,302
S3	6,603,883	980	110,452	5,170	0	6,498,601	-372	17,296
S4	6,604,290	573	110,661	4,810	-360	6,498,439	-534	17,301
S5	6,604,673	191	110,811	5,170	0	6,499,031	58	17,296
S6	6,604,021	842	110,477	4,710	-460	6,498,255	-718	17,296
S7	6,603,964	900	110,372	4,710	-460	6,498,302	-671	17,296
S8	6,604,411	452	110,382	5,170	0	6,499,199	226	17,305
Low price	6,603,630	1,233	108,858	4,450	-720	6,499,222	249	17,296
High price	6,555,220	49,643	132,086	3,070	-2,100	6,426,204	-72,768	36,988

Røssåga

The water capacity in Røssåga is fairly large, and the steepest increase is behind us. The inflow is in a falling trend, and there are only moderate amounts of inflow throughout July. Thus, the guiding from the LTM seems reasonably good. Figure 66 depicts the scheduled plans for the unit Nedre Røssåga G1. The red lines indicates really tight production limits, and S1 and S8 drops below this limit since their respective price scenarios is below the low-price scenario for 1-2 hours. Start-up costs makes the duration of the drop even longer.

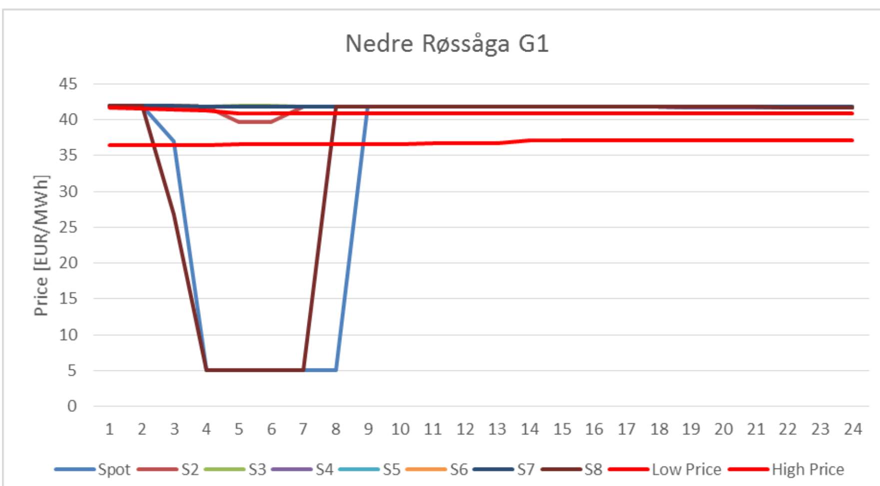

Figure 66 - Scheduled production for Nedre Røssåga G1 in Røssåga river system, 23rd June

The results from the comparative optimization in SHOP is shown in Table 30. The average theoretical improvement potential is 2,022 EUR, which is greater than both the low volatility cases. Hence, the price volatility seems to have an effect on the significance of the price forecasts.

Table 30 - Comparative results for Røssåga river system, 23rd June

Scenario	Income	Potential improvement	Sale	Startup costs	Reservoir value	ΔReservoir
S1	19,111,415	0	2,033,916	9,740	17,087,239	0
S2	19,110,302	1,113	2,045,494	8,760	17,073,568	-13,671
S3	19,110,352	1,063	2,046,663	9,740	17,073,429	-13,810
S4	19,108,334	3,081	2,043,451	8,270	17,073,153	-14,086
S5	19,110,344	1,071	2,046,685	9,740	17,073,399	-13,840
S6	19,107,744	3,671	2,043,862	9,740	17,073,623	-13,616
S7	19,106,787	4,628	2,042,852	9,740	17,073,675	-13,564
S8	19,109,868	1,547	2,032,869	8,760	17,085,759	-1,480
Low price	19,041,165	70,250	1,889,320	9,210	17,161,055	73,816
High price	19,056,913	54,502	2,023,065	9,250	17,043,098	-44,141

The potential improvements can be considerably large for this river system, as well. Low- and high price scenarios amount to an improvement potential of 70,250 EUR and 54,502 EUR, respectively. Hence, the importance of a good price forecast gives economic incentives. Note that it more profitable to produce "too much", than "too little", as the high price scenario has less improvement potential.

NO3

A comparative optimization for the price area NO3 is included to see the volatility effect here as well. The potential improvements have, as expected, higher values than compared with the river systems. However, the average theoretical improvement potential in NO3 is 27,949 EUR, which is equivalent to 0.90 % of the spot-sales.

Scenario	Income	Potential improvement	in % of	Sale	ΔSale	Startup costs	Reservoir value	ΔReservoir
S1	74,874,651	0	0.0000%	3,114,210	0	63,970	71,824,411	0
S2	74,871,009	3,641	0.1169%	3,123,125	8,916	63,430	71,811,314	-13,097
S3	74,870,350	4,300	0.1381%	3,125,063	10,854	63,080	71,808,367	-16,044
S4	74,870,854	3,796	0.1219%	3,123,119	8,909	63,060	71,810,795	-13,616
S5	74,865,055	9,596	0.3081%	3,134,101	19,891	62,980	71,793,934	-30,477
S6	74,829,574	45,076	1.4474%	3,183,757	69,547	62,740	71,708,557	-115,854
S7	74,786,972	87,679	2.8154%	3,234,681	120,472	62,940	71,615,231	-209,180
S8	74,833,099	41,552	1.3343%	3,162,696	48,486	63,200	71,733,603	-90,808

High price level (March 21st)

This period is close to the one being presented in Section 7.3.1, and the characteristics for an energy deficit period becomes even clearer when looking at Figure 67. The price starts an increasing trend in the middle of March, and it lasts throughout the first half of April according to both cases in this period. In addition to this, there are instances of price spikes indicating effect deficit at peak hours. However, March 21st is a Thursday and the price forecasts are up-to-date, unlike the previous examples. Two significant price jumps during peak hours are indicated by the figure, and the demand is therefore intersecting at particularly high MC's at the supply curve.

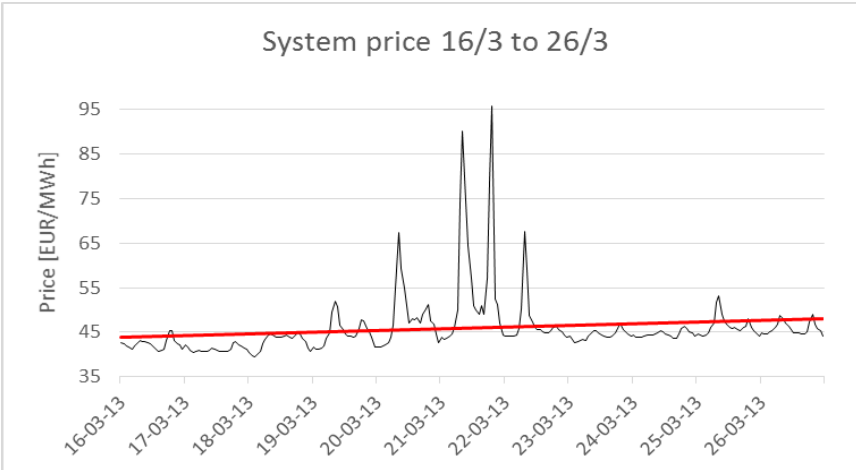

Figure 67 - System price around March 21st

There are no indications about any wind production affecting the price levels, besides that it is in a short-term falling trend. The net exports from Norway are positive, despite the high prices, which indicates that Norway is in favor of relatively low MC's, given that they are normally net importing during this period of the year. A graphical illustration of the mentioned values are given in Figure 68. The black graph shows the average system price, which is relatively high.

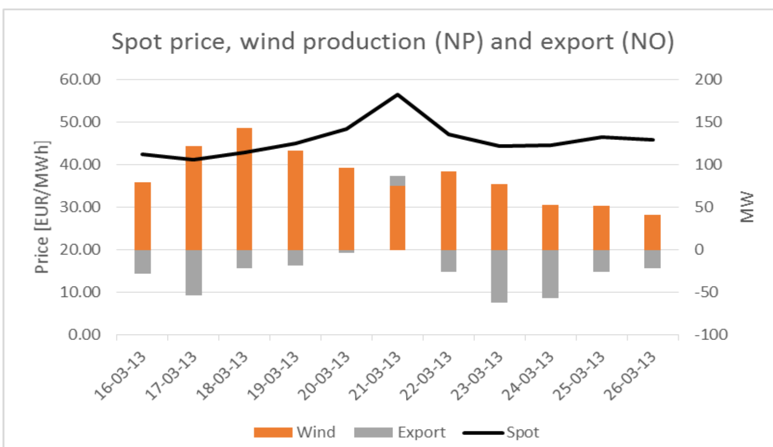

Figure 68 - Spot price (NO), wind production (NP), and net exports (NO) around March 21st

The price series used for the calculations in SHOP are depicted in Figure 69. The price profiles are more or less equal, but the spot price cleared at a higher level than most of the analysts expected. The increased price level can be an effect of e.g. a demand shift, due to lower temperatures. The price series from S2 and S3 are standing out with their ability to predict the second price spike during 18h to 21h. How much this prediction is potentially worth in profits will be carried out from the results.

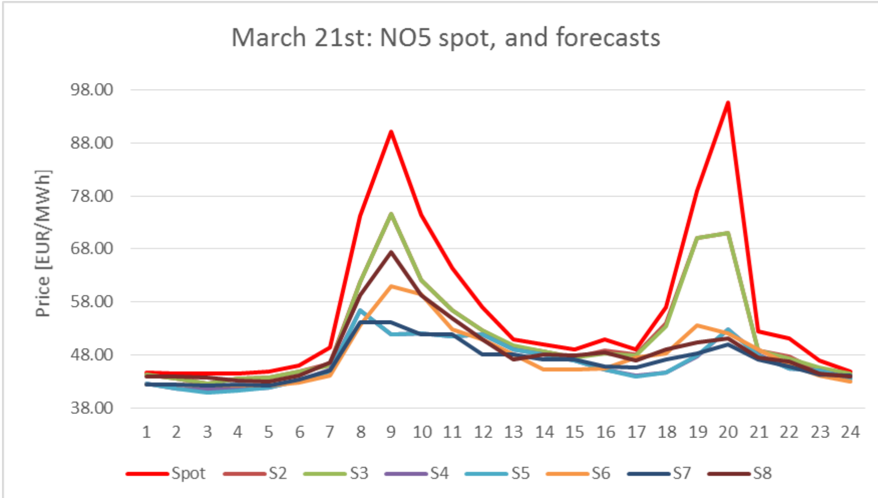

Figure 69 - NO5 spot price, and forecasts for March 21st

Leirdøla

The reservoir level at Leirdøla is nearly empty, and there is almost zero inflow during the nearest future. The WV is 44.5 EUR/MWh, and most of the price scenarios will therefore result in some scheduled generation. The scheduled generation for Thursday 21st of March is shown in Figure 70.

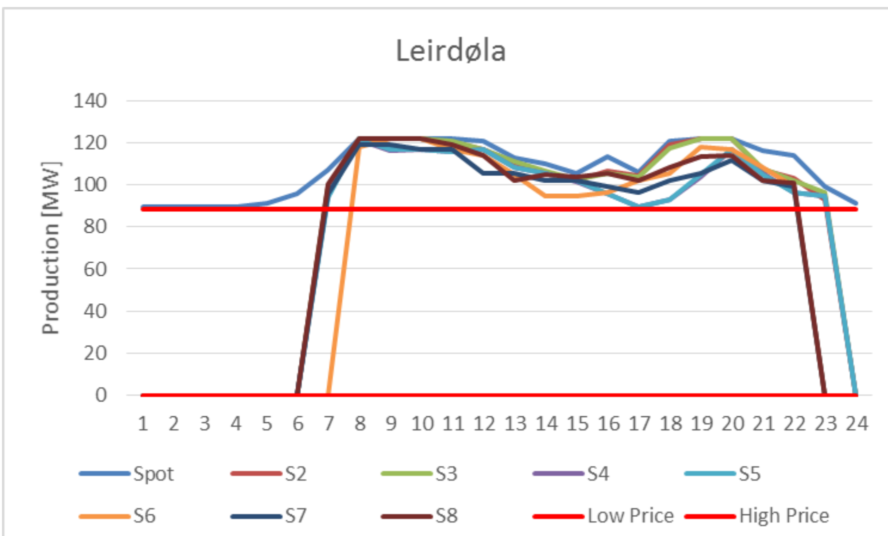

Figure 70 - Scheduled generation for Leirdøla station at March 21st

The maximum limit for the high-price scenario is at the best-point. Since the high-price is constant throughout the optimization period, the optimization model sees no incentives for exceeding the best-point when it already has secured enough profitable sales in the market for all the water that is left in the reservoir.

According to the previous figure there is expected less start-up costs for the spot price scenario, as it is already producing in the beginning of the day being analyzed. The results from the comparative optimization are listed in Table 31. Theoretical, average improvement potential amounted to 1,214 EUR, or 0.1642 % of the spot sales, which is the highest value so far for Leirdøla. Hence it is reasonable to assume that price volatility impacts the theoretical improvement potential.

Table 31 - Comparative results from the optimization of Leirdøla river system, March 21st

Scenario	Income	Potential improvement	Sale	Startup costs	ΔStartup	Reservoir value	ΔReservoir	Penalty
S1	793 228	0	739 376	490	0	54 342	0	0
S2	792 740	488	695 062	1 470	980	99 148	44 806	0
S3	792 740	488	695 074	1 470	980	99 136	44 794	0
S4	791 374	1 854	688 774	1 470	980	104 070	49 728	0
S5	791 414	1 814	688 847	1 470	980	104 037	49 695	0
S6	791 546	1 682	682 126	1 470	980	110 890	56 548	0
S7	791 159	2 069	684 435	1 470	980	108 194	53 852	0
S8	791 909	1 319	687 876	1 470	980	105 503	51 161	0
Low price	761 674	31 554	581 302	980	490	181 351	127 010	0
High price	786 000	7 228	715 169	490	0	71 321	16 979	0

The previous observation of the good spot-price-profile-fit, regarding S2 and S3, seems to have a positive impact on the income, giving the lowest improvement potential. The potentially worst price forecast for this scenario would be a price-series with a low, average price level, scheduling for less than the spot plan. The spot plan is running at about maximum capacity during the day, i.e. the volume sold multiplied with the spot price is the potential income for any price forecast (in addition to any unfortunate start-up costs or penalty). The opposite yields for the low price case, where the optimal plan from the spot price had scheduled for zero production, hence every scenario with a scheduled plan exceeding zero would be punished with the volume sold at the spot price. The absolutely largest potential improvement amounts to 31,554 EUR (compared with 32,884 EUR from the low price example).

Vik

Vik's reservoirs are nearly emptied as well. There are no major inflow expectations, and the WV's varies between 43-44 EUR/MWh. All of the units are exposed for forced scheduling, except Målset station. Refsdal G3 is the unit with the most forced generation during March 21st. Illustrations of the scheduled production is left out of this example, as there already have been presented many similar figures.

The comparative optimization gave the following results listed in Table 32. Note that there are some minor penalty deviations. The hypothesis about S2 and S3 giving the best scheduling among the forecasts, is still valid for Vik as wel. The largest potential improvement amounts to 25,668 EUR, implying that the worst possible forecast is one with lower price levels than the spot price. The previous example with low price levels, gave a maximum potential improvement of 21,025 EUR. It is naturally a close connection with the deviating amount of power being sold to the market, at spot price.

Table 32 - Comparative results for Vik at March 21st

Scenario	Income	Potential improvement	Sale	Startup costs	ΔStartup	Reservoir value	ΔReservoir	Penalty
S1	3 222 683	0	635 432	4 450	0	2 591 701	0	7 757
S2	3 222 475	208	635 039	3 990	-460	2 591 426	-275	7 799
S3	3 222 395	288	627 488	4 450	0	2 599 357	7 656	7 757
S4	3 219 417	3 266	610 938	4 450	0	2 612 929	21 228	7 757
S5	3 219 465	3 218	610 527	4 450	0	2 613 388	21 687	7 757
S6	3 220 995	1 688	615 891	4 450	0	2 609 553	17 852	7 757
S7	3 219 072	3 611	612 139	4 450	0	2 611 382	19 681	7 757
S8	3 221 068	1 615	621 737	4 450	0	2 603 781	12 080	7 757
Low price	3 197 015	25 668	534 514	7 070	2 620	2 669 571	77 869	8 051
High price	3 219 182	3 501	661 932	3 630	-820	2 560 880	-30 821	7 757

The average theoretical improvement potential were 1,737 EUR, or 0.2733 %, hence the improvement potential for Vik was actually greater at low price levels (0.4664 %), relative to the spot sales.

Røssåga

Røssåga has relatively low reservoir levels, but as indicated earlier does this river system have a robust degree of regulation. There is also forecasted moderate amount of inflow to Røssvatn, and the WV's are 29.2 EUR/MWh and 42.6 EUR/MWh. Øvre Røssåga G1 is scheduled for high production for all of the respective scenarios. The same yields for the units downstream, where Nedre Røssåga G1 and G3 are exposed to forced production in addition to the otherwise high production.

The results from the comparative optimization is shown in Table 33. The optimal scheduling is close to maximal capacity, and the potential improvement of the price scenario scheduling for the lowest production is expected to be greatest. This is of course the low-price scenario (due to already high price levels), amounting to a potential improvement of 146,571 EUR. The average theoretical improvement potential for the price forecasts S1 – S8 is 3,931 EUR, equivalent to 0.1183 % of the spot sales. The minor penalties are zero, and therefore not included in the table.

Table 33 - Results from the comparative optimization of Røssåga river system, March 21st

Scenario	Income	Potential improvement	Sale	Startup costs	ΔStartup	Reservoir value	ΔReservoir
S1	34 130 428	0	3 323 557	3 370	0	30 810 241	0
S2	34 129 580	848	3 316 085	3 370	0	30 816 864	6 623
S3	34 129 608	820	3 317 057	3 370	0	30 815 921	5 680
S4	34 120 092	10 336	3 336 253	3 860	490	30 787 699	-22 542
S5	34 117 530	12 898	3 337 059	3 860	490	30 784 331	-25 910
S6	34 128 236	2 192	3 313 170	3 860	490	30 818 926	8 685
S7	34 127 732	2 696	3 304 337	3 370	0	30 826 765	16 524
S8	34 128 771	1 657	3 319 760	3 860	490	30 812 871	2 629
Low price	33 983 857	146 571	2 909 659	4 310	940	31 078 508	268 267

High price	34 118 662	11 765	3 332 914	3 370	0	30 789 119	-21 123

8.3 Intermittent Power Production

This section will present an analysis of day-ahead bidding in price areas, based on the characteristics of wind production in the Nordic market. During periods with high wind production, the supply curve shifts to higher quantity at lower marginal costs (Appendix I), keeping the price level low. From Section 6 we know that the wind is strongest during the winter, and that most of the wind energy within the Nordic market is produced in Denmark or Sweden. The chosen cases are:

- Highest wind production at December 24th
- Lowest wind production at July 26th

8.3.1 High wind production (24. December)

The wind production in the Nordic market were 172.4 GWh during Tuesday, 24th of December. The system price around this date is depicted in Figure 71, with a negative trend line marked with red color. If one compare the price pattern with earlier cases in this Section, one can see that the night prices are particularly low for this case, which can be an effect of the high wind production seen in Figure 72.

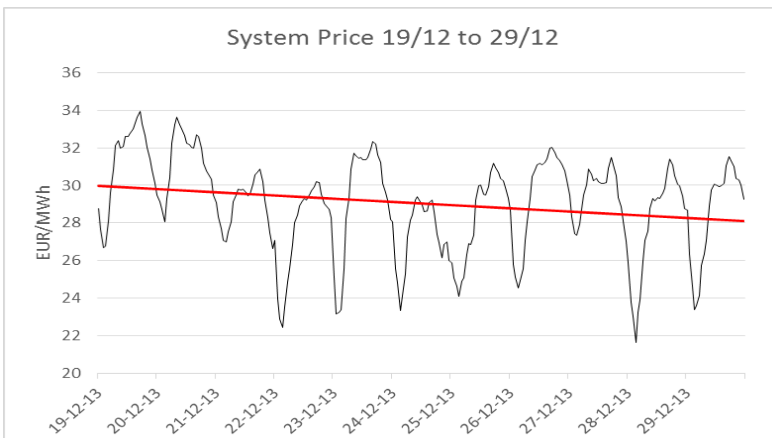

Figure 71 - System price, and trend-line, around December 24th

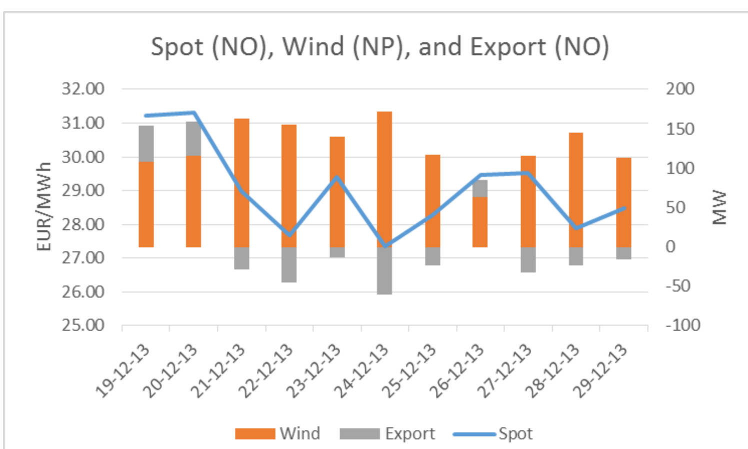

Figure 72 - Daily spot (NO), export (NO), and wind production (NP) around December 24th

Figure 72 does also indicate that Norway imported about 59.9 GWh at December 24th, as well as a relatively low average price for the same day. This is in line with our expectations about a price decrease, due to a shift in positive shift in the supply curve.

The area prices are illustrated in Figure 73 to see if there any obvious effects on the area pricing, due to imports of intermittent power production and demand. NO1, NO2, and NO5 has nearly identical price profiles as seen by the blue graph in the figure. They are relatively flat during the day that are being analyzed. NO3 and NO4 does also have nearly identical price profiles, but they seem to be considerably more affected by the wind production than the other areas.

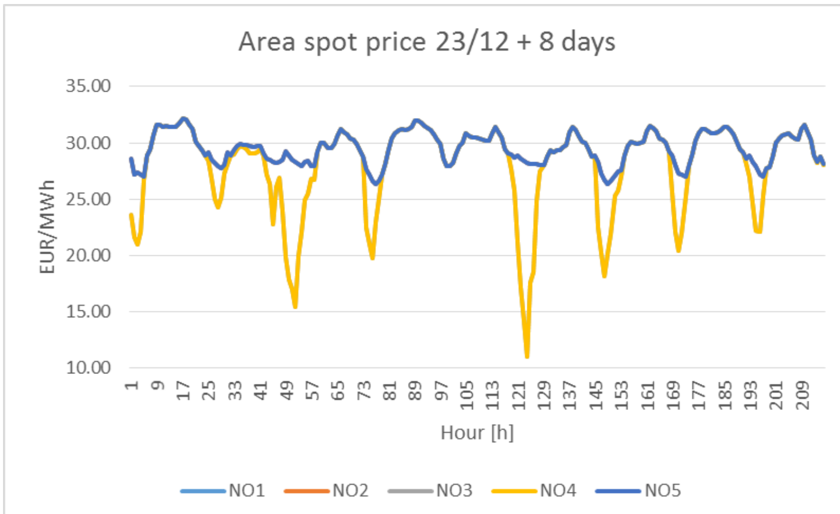

Figure 73 - Area prices from December 23rd and 8 days beyond

Due to the observations in the figures above, the analysis is further pursued for day-ahead bidding in NO2, NO3, and NO4.

NO2

The price forecasts are relatively low, but there is still considerable deviations between their price levels. The results from the comparative optimization is given in Table 34. S2 and S3 is the best price forecasts with respect to income.

Table 34 - Price independent bidding: Comparative results in NO2 at December 24th

Scenario	Income	Potential improvement	in % of	Sale	Startup costs	Reservoir value	ΔReservoir
S1	341,420,460	0	0.0000%	8,186,386	92,190	333,326,264	0
S2	341,311,827	108,633	1.3270%	8,056,865	94,400	333,349,362	23,098
S3	341,311,724	108,736	1.3283%	8,056,167	94,400	333,349,957	23,693
S4	341,289,491	130,969	1.5998%	8,505,640	97,740	332,881,591	-444,673
S5	341,291,685	128,775	1.5730%	8,405,346	101,700	332,988,039	-338,225
S6	341,287,094	133,366	1.6291%	7,759,854	94,880	333,622,120	295,856
S7	341,308,960	111,500	1.3620%	8,049,779	96,290	333,355,471	29,207
S8	341,283,503	136,957	1.6730%	8,695,131	98,310	332,686,682	-639,582

NO3

The price forecasts in the NO3 area is more volatile than in the NO2 area, and it may be reasonable to assume that the scheduled production for the price independent bids therefore will vary more than for the NO2 bids. The optimization results for NO3 is shown in Table 35.

Table 35 - Price independent bidding: Comparative results for NO3, December 24th

Scenario	Income	Potential improvement	in % of	Sale	Startup costs	Reservoir value	ΔReservoir
S1	60,806,763	0	0.0000%	2,419,593	66,885	58,454,056	0
S2	60,806,223	540	0.0223%	2,363,796	66,545	58,508,972	54,916
S3	60,805,886	877	0.0362%	2,357,319	66,545	58,515,112	61,056
S4	60,794,453	12,310	0.5088%	2,567,140	69,385	58,296,698	-157,358
S5	60,794,582	12,181	0.5034%	2,555,556	70,345	58,309,372	-144,684
S6	60,805,039	1,724	0.0713%	2,350,450	66,545	58,521,134	67,078
S7	60,806,395	369	0.0153%	2,378,840	66,545	58,494,099	40,043
S8	60,792,580	14,183	0.5862%	2,597,813	69,635	58,264,402	-189,654

NO4

The price scenarios for NO4 is nearly identical to those used for NO3. Together, NO3 and NO4 has a direct import capacity from Sweden amounting to 1900 MWh/h (Section 6), which may be a potential contributor to any wind production ripple effects. The comparative optimization results are listen in Table 36.

Table 36 - Price independent bidding: Comparative results for NO3, December 24th

Scenario	Income	Potential improvement	in % of	Sale	Startup costs	Reservoir value	ΔReservoir
S1	198,970,077	0	0.0000%	8,133,835	97,390	190,933,631	0
S2	198,959,947	10,130	0.1245%	7,933,101	95,710	191,122,556	188,925
S3	198,955,787	14,290	0.1757%	7,850,630	94,380	191,199,537	265,906
S4	198,936,157	33,920	0.4170%	8,474,700	104,350	190,565,807	-367,825
S5	198,935,380	34,697	0.4266%	8,468,108	104,310	190,571,582	-362,049
S6	198,953,724	16,353	0.2010%	7,818,009	94,390	191,230,105	296,473
S7	198,960,535	9,541	0.1173%	8,160,852	96,790	190,896,474	-37,158
S8	198,932,527	37,550	0.4616%	8,546,413	102,840	190,488,954	-444,677

A comparison of the theoretical improvement potential for the price forecasts, in respective price areas, are shown in summary in the results section (Section 9.2.1). A graphical illustration of the theoretical improvement potential for each price scenario, in the three mentioned price areas, are depicted in Figure 74. NO2 has by far the largest potential, relative to the spot sales. Note the performance of S2, S3, and S7 in the NO3 area, which is overall relatively good.

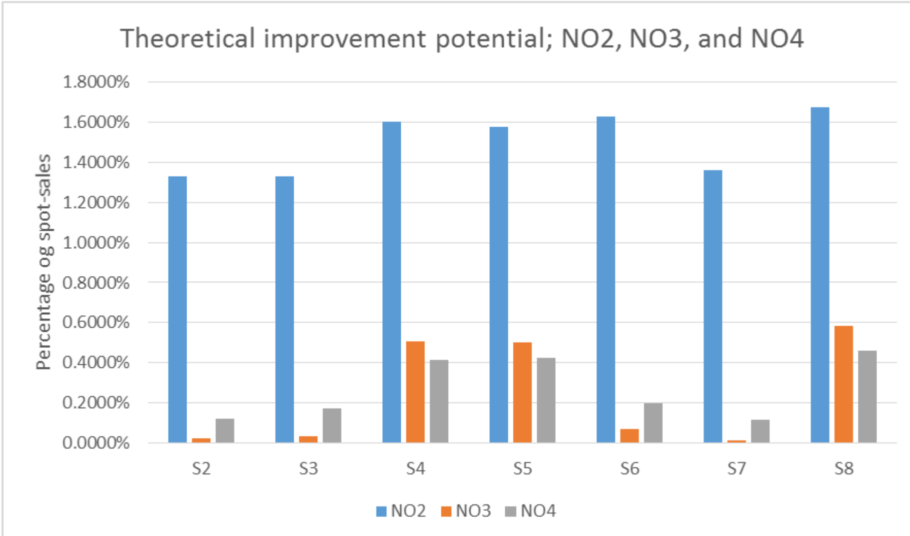

Figure 74 - Comparison of theoretical improvement potential in NO2, NO3, and NO4 during December 24th

8.3.2 Low wind production (26. July)

The lowest wind production in the Nordic market were recorded at Friday July 26th, amounting to 6.5 GWh. The spot price around this date is depicted in Figure 75. The trending price is relatively flat according to the red trend-line in the figure. The wind power production in the Nordic market and net exports from Norway are shown in Figure 76.

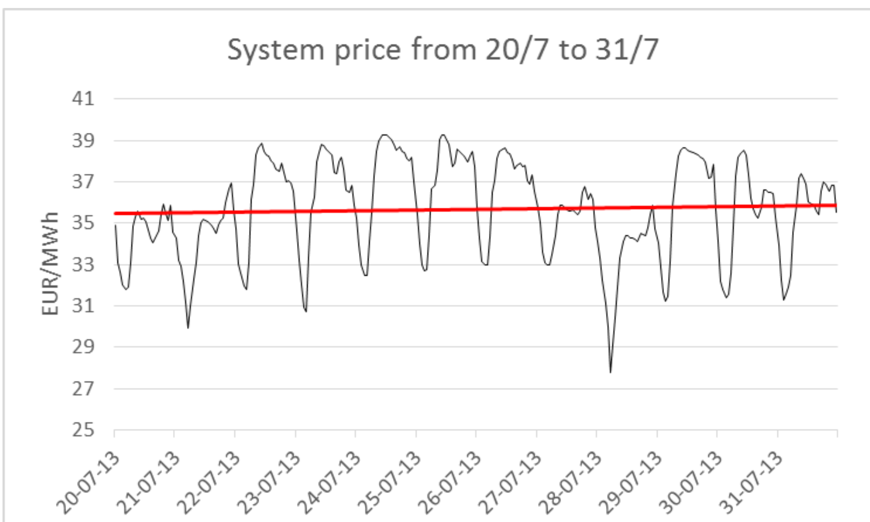

Figure 75 - System price around July 26th

Figure 76 shows that the average price increases as the wind power production decreases. This might be a coincidence due to only a slightly decrease in wind power supply. Anyway, the net exports in Norway reaches 88.3 GWh for July 26th, which is a considerable large amount comparing with all time high at 96 GWh. The question is; which price areas are most affected by this export value?

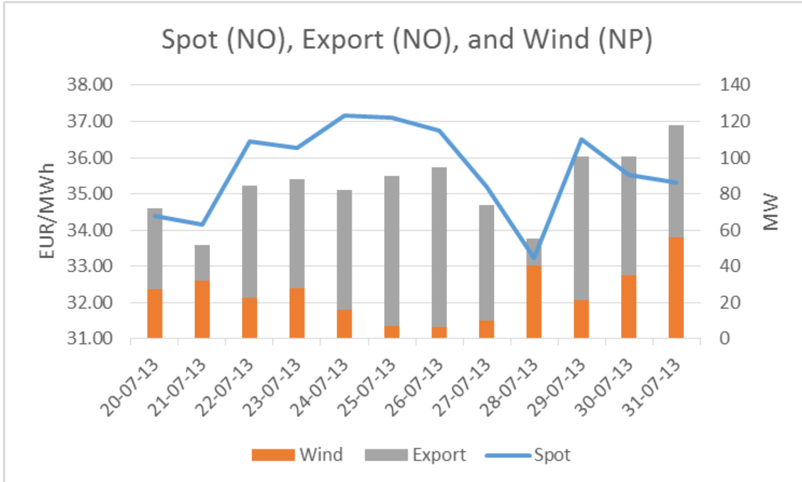

Figure 76 - Daily spot price (NO), export (NO), and wind production (NP). Around July 26th

Recall that the spot price in NO3 and NO4 had a lower average price profile than the rest of the areas during the period with high wind production. They did also have downward price spikes during the night. The same illustration for the period with low wind production is depicted in Figure 77, but in this case the spot price in NO3 and NO4 is higher on average. In addition to this, they do now have upward price spikes, which is particularly high in NO3 during some peak hours. Notice that NO2 also have some minor price lifts. It is naturally the price areas with the largest interconnection capacity that are most affected, an especially NO3 which also is a relatively large consumer itself due to the Trondheim area.

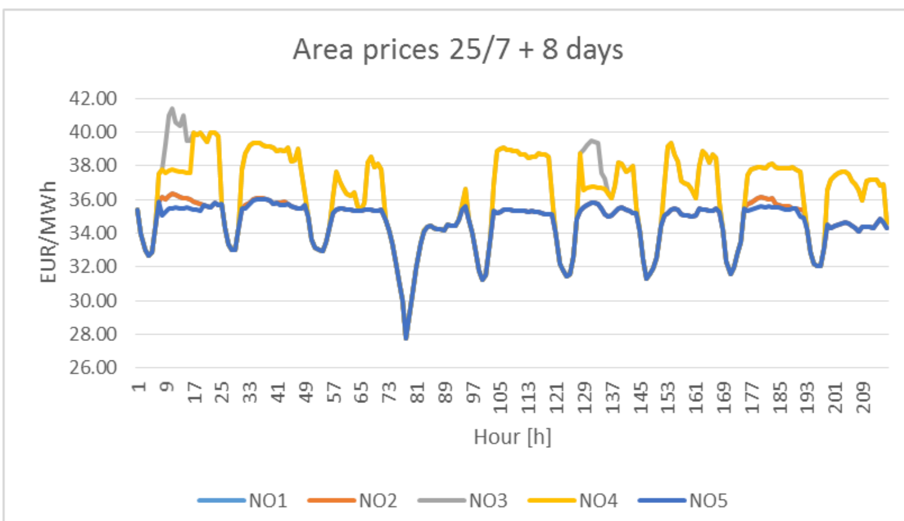

Figure 77 - Area prices in Norway during 25th of July and 8 days beyond

The comparative calculations with SHOP gave potential improvements amounting to average values of 95,000 EUR in NO2, 1,170 EUR in NO3, and 5,000 EUR in NO4. A relative comparison with the reference scenario's spot-sale value is shown in Figure 78.

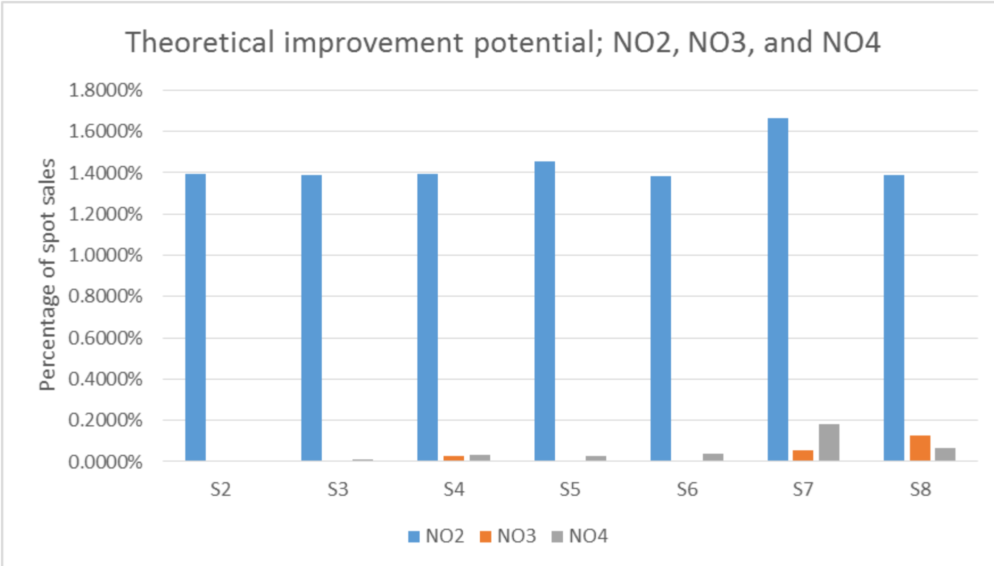

Figure 78 - Comparison of theoretical improvement in NO2, NO3, and NO4 at July 26th

From previous cases in this section, we know that July month consists of relatively high inflow, and in some cases forced production. The significance of the price forecasts are therefore slightly more valuable in cases like this, where the scheduled production in a price are may vary considerably among the price scenarios, due to relatively low prices around the water value levels. The average increase in theoretical improvement potential were 0.17 %, from the winter scenario (0.51 %) to the summer scenario (0.67 %).

8.4 Weekends and Holidays

As seen from Sunday, March 31st in Section 8.1 the price forecasts that were made during the last workday (Wednesday) did not match the actual spot price very well, due to red-calendar days (Norwegian: "Skjærtorsdag", "Langfredag"). This section will summarize some of the available holiday-affected optimization results, and try to reveal potential value of updating price forecasts during the holidays. The following two illustrative cases are presented:

- Sunday 31st of March
  - Three river systems
    - Relate to Friday 4th of January
- Monday 8th of April
  - NO4
    - Relate to Thursday 14th of March

Sunday 31st of March (last work-day: Wednesday 27th of March)

Table 37 - Theoretical improvement results (EUR and % of spot-sale) at Sunday, March 31st

Scenario	Leirdøla		Vik		Røssåga	
S1	0	0.0000%	0	0.0000%	0	0.0000%
S2	0	0.0000%	938	0.1158%	838	0.0222%
S3	0	0.0000%	897	0.1106%	49	0.0013%
S4	0	0.0000%	1,176	0.1451%	1,755	0.0466%
S5	0	0.0000%	1,129	0.1392%	1,939	0.0514%
S6	0	0.0000%	669	0.0826%	26	0.0007%
S7	0	0.0000%	842	0.1039%	782	0.0207%
S8	0	0.0000%	557	0.0687%	25	0.0007%
Low price	0	0.0000%	2,664	0.3286%	112,739	2.9914%
High price	0	0.0000%	7,264	0.8960%	36,053	0.9566%
Average	**0**	**0.0000%**	**776**	**0.0957%**	**677**	**0.0180%**

The average theoretical improvement values in Table 37 are calculated as an average of the eight price scenarios, i.e. excluding the low- and high price. Leirdøla can be disregarded in this example, since it had empty reservoir levels at this date.

The nearest comparative date is Friday 4th of January. The average improvement potential at this Friday were 369 EUR (0.0550 %) for Vik, and 362 EUR (0.0131 %) for Røssåga. Comparing these values with the ones given for Sunday 31st of March in Table 37, one can see that the potential improvements were slightly higher for the weekend-case due to possibly poorer forecasts. However, it would not be enough to compensate for manpower making new price forecasts in the weekends.

Monday 8th of April (last work-day Friday 5th of April)

The detailed results from the optimizations can be found in Appendix IV. A comparative listing for the theoretical improvement potential at Monday 8th of April, and Thursday 14th of March, is shown in Table 38.

Table 38 - Theoretical improvement results (EUR and % of spot-sale) at Monday 8th of April, and Tuesday 14th of March

Scenario	NO4, Monday 8/4		NO4, Thursday 14/3	
S1	0	0.0000%	0	0.0000%
S2	215,283	0.8986%	6291	0.0286%
S3	192,673	0.8042%	6793	0.0309%
S4	141,253	0.5896%	11955	0.0543%
S5	141,560	0.5909%	12971	0.0589%
S6	61,083	0.2550%	4556	0.0207%
S7	7,703	0.0322%	6068	0.0276%
S8	165,885	0.6924%	5510	0.0250%
Average	**115,680**	**0.4829%**	**6,768**	**0.0308%**

There is a considerable large deviation in the improvement potential for the two days compared in Table 38, amounting to an average difference of 108,915 EUR, or 0.4521 %. Given that the Thursday is more or less a good benchmark for a typical work-day, the Monday-bid is absolutely worth investigating. Both forecast for the respective dates are depicted in Figure 79, where Monday 8th of April is in the left graph, and Thursday 14th of March in the right graph.

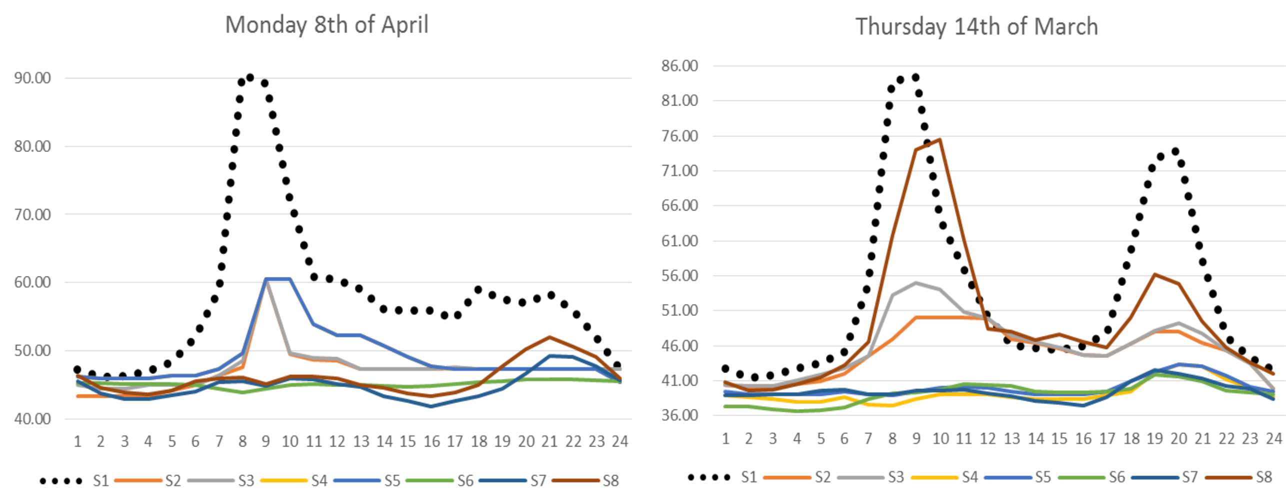

Figure 79 - Price forecasts for Monday 8/4 (calculated 3 days earlier) and Thursday 14/3 (calculated 1 day earlier)

Both days in Figure 79 seems to be affected by energy- and effect deficit, hence the significant price spike during peak hours. However, the Thursday forecasts (S2 and S3) shows a considerable ability to catch up with some of the potential with respect to the spot price, stippled black line. The forecasts for Monday does not catch up with much of the potential, and it is therefore assumed that if the price forecasts were updated at Sunday (one day upfront) the price forecasts would have been considerably more accurate.

Note that the naïve forecast (recent day's spot price) would been a good alternative for the Thursday, which we have seen from earlier examples as well during extreme market conditions (e.g. energy + effect deficit). The naïve scenario for Monday's are often bad approximations anyway, since weekends and weekdays have very different price profiles (Section 6.5).

The conclusion is that in situations like this, given that the producer practices price independent bidding, a forecast update upfront to Monday 8th of April could have a considerable value. S7 obtains about 108,000 EUR only for the small profile change illustrated by the blue line, to the left in Figure 79. Hence, the probability of obtaining the same amount, or more, is assumed favorable for a hydropower producer.

9 RESULTS

The results chapter is more or less a summary of the findings so far in the report. The first part is a comparison of the inflow- and price uncertainty effect on income, where the inflow is expected to be less influential than price. Hence, a stochastic model accounting for price uncertainty would be more valuable than only accounting for inflow uncertainty. The second part cover price uncertainty, starting by a comparison of different bidding strategies to stress that the price independent methodology in this thesis is a good benchmark for theoretical improvement potential. As well as pinpointing the value of flexibility, in the context of treating price as a stochastic variable. The second part ends with summarizing the price-related findings in this report. Finally, some alternative SHOP analyses is presented in the third part, representing the evaluation of *certain* decision-/modelling parameters.

9.1 INFLOW UNCERTAINTY

Uncertainty about future, local inflow is expected to have less influence on the ST production scheduling, than price uncertainty has (Vardanyan, 2012). As long as a reservoir has the capacity to store eventual inflow, the scheduled production will remain the same, given an independent future water value. However, the inflow may have an indirect impact on the water values which is not reflected in SHOP. Analysing the impact of this indirect relationship is not within the scope of this thesis, but a principal interpretation of the effect will be listed among the other possible ST inflow-effects below.

1. When the water level in the reservoirs are empty
    a. Price > WV: May schedule inflow for production
    b. Price < WV: No production

2. When the water level in the reservoirs is sufficient to cover any production, as well as low enough to avoid potential spillage
    a. Price > WV: No production scheduling of inflow
    b. Price < WV: No production scheduling of inflow

3. When the water level in the reservoirs is exposed for spillage-risk
    a. Price > WV: Inflow will be scheduled for production
    b. Price < WV: Forced production due to spillage risk

4. Indirect effects on ST scheduling
    a. ST inflow may contribute higher end-reservoir levels, relative to the LT strategy. Hence the WV should be lower, thus more production should be scheduled ST.
    b. Less ST inflow gives to opposite effect; lower end-reservoir levels, relative to LT strategy. Hence WV should be higher, and scheduled production lower.

The hypothesis for ST inflow uncertainty is therefore

- Inflow uncertainty does not affect reservoirs with a high degree of regulation, since they normally don't reach their limits
- Inflow uncertainty may have an impact on reservoirs with a low degree of regulation, since they often reach their limits (seasonally)

- Inflow uncertainty has minimal impact during winter season, when inflow is flat/low
- Inflow uncertainty has minimal impact during flood-period

The potential of realizing eventual profits from inflow uncertainty, is insecure, meaning that it is difficult to achieve its maximum potential in practice.

9.1.1 Medium Reservoir during Flood- and Filling

An example is carried out for Leirdøla river system, and it represents the middle of flood- and filling periods. The station has a maximum discharge capacity of 29 m^3/s, thus the inflow will be increased from zero to around this value. The water value is calculated as an average value of the reference price for the optimization (i.e. the spot price). The average water value is for providing better illustrations of eventual variations of price and inflow.

Figure 80 shows the scheduled production with respect to different amounts of inflow, spanning from 0 m^3/s to 40 m^3/s. One can observe that the production is nearly identical, and the short-term income is therefore not affected by the increased inflow. Hence, one can expect that the inflow "forecasts" has no value for the short-term water management in this case.

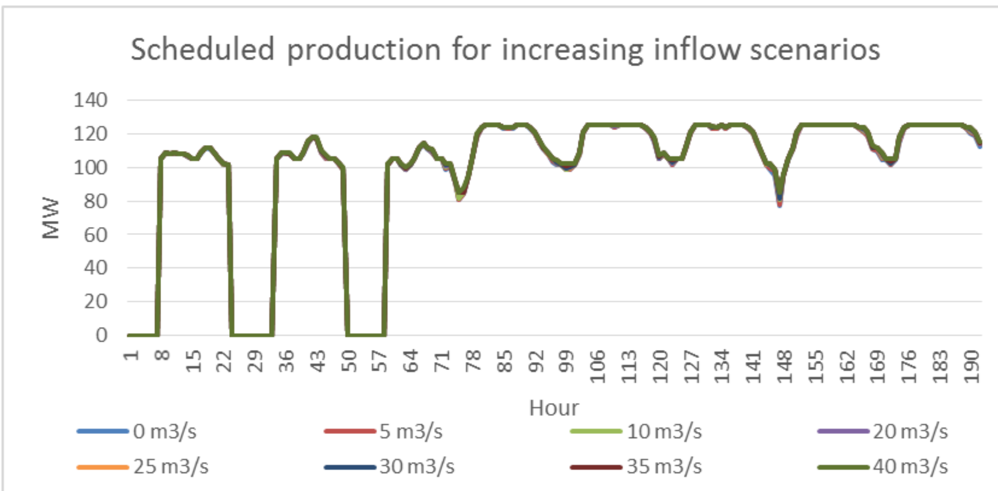

Figure 80 - Scheduled production with respect to increasing inflow (Leirdøla)

A comparative optimization of a few selected inflow scenarios are listed in Table 39. The comparative optimization is ran with locked production plans (as depicted in Figure 80), zero inflow, spot price, and identical water values. Hence, the income and end-reservoir values are more or less equal for the respective inflow scenarios.

Table 39 - Comparative results regarding inflow scenarios at Leirdøla, medium reservoir levels (flood/filling periods)

Inflow Scenario	Income	Potential improvement	in % of	Sale	ΔSale	Startup costs	Reservoir value
20 m3/s	4,869,474	0	0.00%	673,824	0	1,960	4,197,610
30 m3/s	4,869,474	0	0.00%	673,863	39	1,960	4,197,571
40 m3/s	4,869,474	0	0.00%	673,924	101	1,960	4,197,509
50 m3/s	4,869,473	0	0.00%	674,042	0	1,960	4,197,391

To illustrate the inflow effect in context with price variations, Figure 81 is included and it shows the scheduling effect of variations in price. The price variations in the figure are based on +/- 10 - 90% deviations from the reference price (spot). The water value is the same as in the inflow-case, i.e. an average value of the spot price.

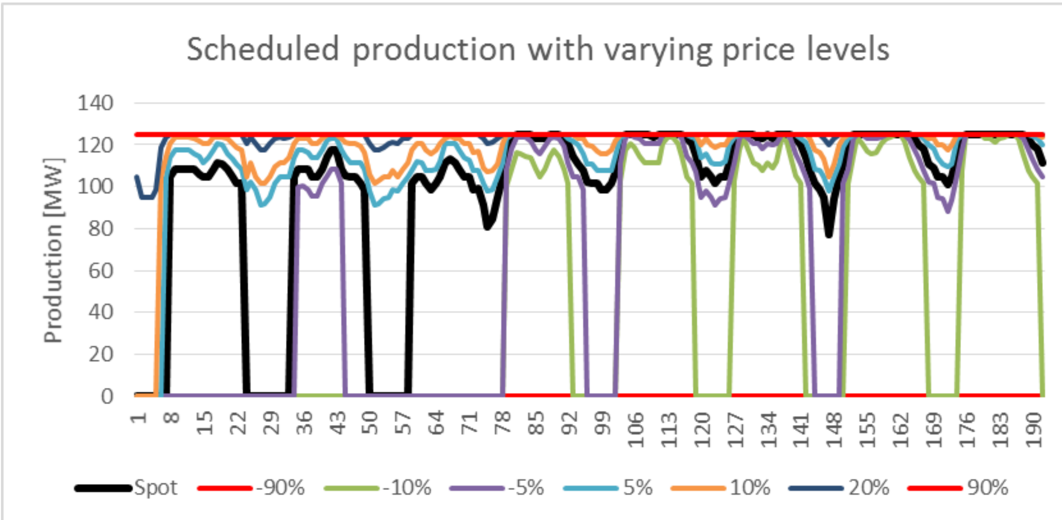

Figure 81 - Scheduled hourly production with respect to varying price scenarios (Leirdøla)

A comparative optimization of the price scenarios in Figure 81 are listed both with respect to the whole optimization period and the day-ahead scheduling, in respectively Table 40 and Table 41. Meaning that the production plans were locked for both the whole optimization period, and only for the day-ahead (as usual), in separate optimizations with respect to the same spot price.

Table 40 - Comparative optimization of the price variations at Leridøla during medium reservoir levels (flood and filling). Potential improvement is measured as the whole optimization period (not only day-ahead).

Price Scenario	Income	Potential improvement	in % of	Sale	Startup costs	Reservoir value	ΔReservoir
Spot	4,868,363	0	0.0000%	746,130	1,470	4,123,703	0
-90%	4,799,958	68,405	9.1680%	-84	0	4,800,042	676,338
-10%	4,861,267	7,096	0.9511%	387,400	2,450	4,476,317	352,614
-5%	4,866,781	1,582	0.2120%	524,406	1,960	4,344,335	220,631
5%	4,863,362	5,001	0.6702%	841,296	490	4,022,556	-101,147
10%	4,860,465	7,898	1.0586%	871,794	490	3,989,160	-134,543
20%	4,856,022	12,341	1.6541%	911,605	0	3,944,416	-179,287
90%	4,854,464	13,899	1.8628%	919,543	0	3,934,921	-188,782

Table 40 is not a realistic application of a price forecast (represented as the price deviations), but it is more illustrative for price uncertainty over a longer period of time, than just for the day-ahead shown in Table 41. The theoretical improvement potential is greater for a longer time-horizon, as implied by comparing the tables.

Table 41 - Comparative optimization of the price variations at Leridøla during medium reservoir levels (flood and filling). Potential improvement is measured as day-ahead.

Scenario	Income	Potential improvement	in % of	Sale	Startup costs	Reservoir value	ΔReservoir
Spot	4,869,391	0	0.0000%	682,948	1,960	4,188,403	0
-90%	4,868,550	842	0.1232%	621,299	1,470	4,248,720	60,317
-10%	4,868,550	842	0.1232%	621,299	1,470	4,248,720	60,317
-5%	4,868,550	842	0.1232%	621,299	1,470	4,248,720	60,317
5%	4,868,782	610	0.0893%	694,682	1,960	4,176,059	-12,344
10%	4,868,098	1,293	0.1893%	702,424	1,960	4,167,635	-20,769
20%	4,867,011	2,380	0.3485%	721,414	1,470	4,147,068	-41,336
90%	4,866,232	3,159	0.4625%	726,258	1,470	4,141,444	-46,959

Comparing both the inflow- and price effect from this Leirdøla-case, it becomes obvious that variations in price has more impact than variations in inflow, during the middle of flood- or filling periods for a medium sized reservoir. The theoretical improvement potential were on average 2.23% and 0.21%, relative to the spot price sales, for the price variations over 8 days and 1 day, respectively. The theoretical improvement of the inflow scenarios were 0% on average for both day-ahead- and period production scheduling.

9.1.2 Medium Reservoir with Spillage Risk

The reservoir level is almost at full capacity, and there is forecasted some inflow as well in this case (beginning of October 2013). The forecasted inflow, including the constant inflow scenarios up till 30 m3/s results in equal production scheduling, which can be seen in Figure 82. The resulting production plans for 40 m3/s and 50 m3/s are most likely an effect of forced production, due to the risk of spillage.

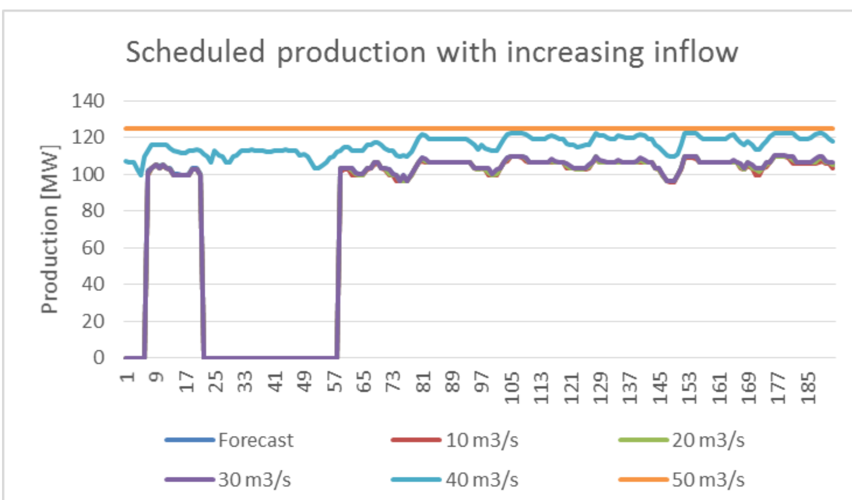

Figure 82 - Scheduled production with respect to increasing inflow at Leirdøla

Figure 83 illustrates the same inflow arrangement as in Figure 82, but with extremely low prices that reveal eventual forced production.

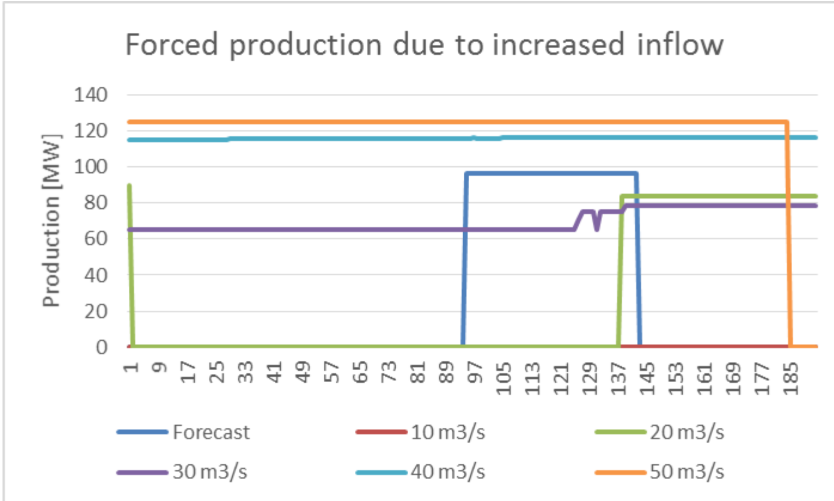

Figure 83 - Forced generation to avoid spillage, with respect to increasing inflow

The fact that the inflow scenarios potentially can impact the scheduling, implies that there are potential values of a good inflow forecast during cases where a reservoir is exposed to spillage. This assumption is confirmed with Figure 83, where forced production is indicated for all of the inflow scenarios above 20 m3/s, including the actual inflow forecast. The comparative inflow-results are listed in Table 42 for the whole optimization period, with respect to zero inflow, equal water value, and identical spot price.

Table 42 - Comparative optimization of inflow scenarios at Leirdøla with high reservoir level and spillage risk. Theoretical improvement measured as the whole period (not only day-ahead)

Inflow Scenario	Income	Potential improvement	in % of	Sale	Startup costs	Reservoir value	ΔReservoir
Forecast	7,514,073	0	0.0000%	594,035	980	6,921,017	0
10 m3/s	7,514,073	0	0.0000%	590,641	980	6,924,416	3,398
20 m3/s	7,514,073	0	0.0000%	592,837	980	6,922,223	1,205
30 m3/s	7,514,070	3	0.0005%	595,204	980	6,919,846	-1,172
40 m3/s	7,511,027	3,045	0.5126%	838,586	0	6,672,442	-248,576
50 m3/s	7,504,088	9,984	1.6808%	903,087	0	6,601,001	-320,016

From Figure 82 we see that the maximum theoretical improvement potential is for the 50 m3/s scenario, which is scheduled at maximum capacity. This can be compared with the maximum theoretical improvement potential for price uncertainty.

The same comparative optimization as in Table 42, is executed as for the day-ahead, meaning the inflow effect for only the day-ahead production scheduling. These results are listed in Table 43.

Table 43 - Comparative optimization of inflow scenarios at Leirdøla with high reservoir level and spillage risk. Theoretical improvement measured as day-ahead.

Inflow Scenario	Income	Potential improvement	in % of	Sale	Startup costs	Reservoir value	ΔReservoir
Forecast	7,515,626	0	0.0000%	672,468	1,470	6,844,629	0
10 m3/s	7,515,625	1	0.0001%	672,273	1,470	6,844,822	194
20 m3/s	7,515,625	1	0.0001%	672,312	1,470	6,844,784	155
30 m3/s	7,515,626	1	0.0001%	672,363	1,470	6,844,733	105
40 m3/s	7,514,491	1,135	0.1688%	712,649	980	6,802,822	-41,807
50 m3/s	7,513,064	2,562	0.3810%	724,471	980	6,789,573	-55,055

The conclusion from this Leirdøla-case, with high reservoir level and spillage risk, is that the inflow uncertainty has some value due to the optimal scheduling of forced production. For example, if the inflow forecast is higher than the actual inflow, it could have scheduled for more forced production than optimal, and vice versa if the forecasted inflow is lower than actual. The price uncertainty is expected to have nearly the same maximum improvement potential, due the same denominator; maximum production capacity. Comparative results from a price scenario optimization is included to see if this assumption is correct, in Table 44.

Table 44 - Comparative optimization results of price scenarios at Leridøla during high reservoir level and spillage risk. Day-ahead.

Scenario	Income	Potential improvement	in % of	Sale	Startup costs	Reservoir value	ΔReservoir
S1	7,515,655	0	0.0000%	676,901	1,470	6,840,224	0
S2	7,515,653	2	0.0003%	680,334	1,470	6,836,793	-3,431
S3	7,515,653	2	0.0003%	680,322	1,470	6,836,805	-3,419
S4	7,515,651	4	0.0006%	677,717	1,470	6,839,404	-820
S5	7,515,651	4	0.0006%	677,717	1,470	6,839,404	-820
S6	7,515,562	93	0.0137%	685,739	1,470	6,831,294	-8,930
S7	7,515,390	265	0.0391%	669,536	1,470	6,847,324	7,100
S8	7,515,608	47	0.0069%	676,773	1,470	6,840,305	82
Low Price	7,514,996	659	0.0973%	615,450	980	6,900,526	60,302
High Price	7,513,064	2,591	0.3827%	724,471	980	6,789,573	-50,651

The average improvement potential for the price scenarios were 0.062 % with respect to the spot-sales. When only account for the extreme-scenarios (low and high), the average improvement amounted to 0.240 %. The potential improvement for the extreme inflow scenarios (min and max) were 0.191 %. Note that the maximum improvement potential in both cases, for price and inflow, were nearly identical at 2,591 EUR and 2,562 EUR, respectively.

9.1.3 Summary

The inflow- and price comparison is summarized in Table 45. The inflow analysis showed that the hydropower scheduling were nearly independent of the short-term inflow, except for situations when the system(s) are exposed to spillage risk. However, the overall results shows that the average improvement potential of price variations is greater than for inflow variations. The average value is calculated in such way that it covers the interval between tangent deviations (max and min).

Table 45 - Summary of price- and inflow comparison at Leirdøla during 4/1 (with storage capacity) and 10/10 (with spillage risk)

Case	Leirdøla	
Inflow, and storage capacity (4/1)	0	0.0000%
Price uncertainty, day-ahead (4/1)	1,424	0.2085%
Price uncertainty, whole period (4/1)	16,603	2.2252%
Price average	**9,013**	**1.2169%**
Forecast scenarios (10/10)	59.43	0.0088%
Inflow, spillage risk day-ahead (10/10)	1,849	0.2749%
Inflow, spillage risk whole period(10/10)	6,515	1.0967%
Inflow average	**4,182**	**0.6858%**

9.2 PRICE UNCERTAINTY

The price forecasts has greater influence on the respective scheduling in SHOP, but the impact may vary depending on its application. As for price independent bidding in the day-ahead market it can give considerable economic incentives for matching the forecast with the spot price, as good as possible. But relative to the value of sold energy to the market, it is usually not that influential. Price dependent bidding is based on multiple price scenarios with the price forecasts as reference, and this method will therefore retrieve some of the potential economic gain of price independent bids, i.e. it is more flexible and accounts for some uncertainty. The flexibility has its value, and the committed volume from a price dependent bidding will be less dependent on small changes in a price forecast. The two mentioned applications for price forecasts in SHOP are summarized below.

- Price independent bidding
- Price dependent bidding (multi-scenario)

Recall that the operational bidding at Statkraft is nearly independent of the price forecast, as it only generates PQ-relationships based on the physical situation in SHOP. However, there are a few exceptions from this method as well, e.g. for less flexible systems who has tight limits for possible production scheduling.

The hypothesis breaks down to:

- Short-term price uncertainty has less impact on day-ahead bidding than we might think
    - The potential improvement of price independent bidding is the benchmark for this assumption, reflecting the maximum theoretical improvement potential due to income effects.
    - Exception: River systems that bids price independent

The potential of realizing eventual profits from price uncertainty, is insecure, meaning that it is difficult to achieve its maximum potential in practice.

9.2.1 Comparison of Bidding Strategies

The goal with this section is to illustrate the flexibility of price dependent bidding, put in context with price independent bidding. The initial scope of this thesis was, among other things, to compare the theoretical improvement potentials of price forecasts used in both bidding independent, and dependent, to the day-ahead spot price. The income-comparison turned out to be a bit more complicated than expected due to complications with using the committed price-dependent volumes as load obligations for whole price areas in SHOP, for a comparative optimization. In addition, the theoretical comparison becomes more or less inconsistent due to the lack of ability to catch up any “wrong decisions” in the respective methods, compared with the optimal commitment which is the price independent bid with respect to the spot price. However, it is possible to compare only the committed volumes from the different day-ahead bidding strategies, and multiply these with the spot price to reveal a decent, comparative value. Table 46 at the next page shows the results from the following bidding strategies:

- Price dependent
    - SHOP bids (linear and step method used between break points)
    - PQ-bids (operative)
- Price independent

- SHOP-forecast-bid
- SHOP-spot-bid (optimal)

Table 46 - Volume commitments in the day-ahead market due to price dependent (SHOP)-, price dependent (operative)-, and price independent (SHOP) bidding for NO4 at March 14th

NO4 14. March	Committed Volumes								
	Based on forecasted price			Based on spot price			Operativ	Optimal	Independent
Hour	Forecasted Price	Step	Linear	Spot Price	Step	Linear	PQ Committment	SHOP Spot	SHOP Forecast
1	40.8	1,629	1,676	42.8	1,944	2,016	2,194	2246.20	1736.48
2	40.2	1,480	1,678	41.44	1,706	1,918	1,960	2102.95	1716.74
3	40.2	1,477	1,676	41.84	1,778	1,995	2,023	2180.10	1716.73
4	40.5	1,575	1,692	42.69	1,918	2,051	2,172	2248.36	1716.73
5	41.5	1,588	1,845	43.52	2,190	2,233	2,230	2322.51	1789.26
6	43.1	2,050	2,202	45.12	2,341	2,399	2,239	2401.93	2278.43
7	44.5	2,213	2,392	54.66	2,510	2,516	2,377	2525.83	2385.78
8	61.9	2,577	2,577	83.92	2,625	2,625	2,377	2631.15	2537.07
9	72.5	2,559	2,578	84.41	2,569	2,601	2,377	2631.10	2546.07
10	70.4	2,555	2,584	63.98	2,551	2,569	2,377	2536.66	2546.02
11	67.1	2,574	2,584	57.04	2,346	2,534	2,377	2526.41	2540.28
12	59.1	2,577	2,576	50.18	2,525	2,534	2,353	2478.29	2516.35
13	53	2,569	2,569	46.03	2,429	2,500	2,333	2406.87	2496.16
14	51.2	2,519	2,528	45.68	1,247	2,312	2,327	2404.22	2492.04
15	47.6	2,483	2,498	45.39	2,265	2,361	2,322	2404.17	2445.70
16	47	2,397	2,479	45.91	2,368	2,426	2,333	2404.11	2441.14
17	47	2,452	2,452	47.88	2,480	2,480	2,350	2453.19	2441.08
18	49.5	2,467	2,493	59.72	2,540	2,545	2,353	2535.79	2478.94
19	52.1	2,485	2,513	72.8	2,555	2,557	2,353	2547.08	2513.20
20	59.5	2,497	2,511	73.9	2,547	2,548	2,353	2547.02	2540.24
21	52	2,331	2,484	58.09	2,521	2,525	2,325	2533.11	2513.91
22	49	2,176	2,444	47.24	1,782	2,200	2,309	2454.92	2488.95
23	44.5	2,070	2,340	44.38	2,037	2,328	2,232	2385.09	2396.97
24	41.2	1,735	2,107	42.48	2,153	2,291	2,134	2286.35	1843.26
Total Sales [EUR]		53,035	55,478		53,927	57,064	54,780	58,193	55,118
Potential improvement [EUR]		**5,158**	**2,715**		**4,266**	**1,129**	**3,413**	**0**	**3,076**

The price dependent bids in SHOP are created with *The Bid-Matrix Program* which were introduced in Section 4.4, both with commitments to price forecast and spot price. The input price scenarios to the bid-matrix program were constant deviations from the price forecast listed under the second column in Table 46. The same price forecast were used to calculate the price independent bid under the column *SHOP Forecast*.

The operative day-ahead commitments were given by the production planners at the dispatch centre in Oslo, under the column *PQ Commitment*. The same volume were double-checked with the historical time-series in SHOP (ICC), which were identical. Finally, the optimal reference for the day-ahead bids were calculated as a price independent spot bid, listed under the column *SHOP Spot*.

First off, the price dependent method with linear break-point interpolation gives a very robust volume commitment, which also were stated by (Bakkevik, 2005). The (modified) potential improvement amounts to 2,715 EUR for this bidding strategy which is the best one among those in this example (1,129 EUR). For the same method with respect to the spot price, which is expected to be close to optimal scheduling, does result in minor potential improvement as well, due to unfortunate scheduling based on a linearization (or step) between the break-points. For example, influential relationships, like PQ/MC, that affects the scheduling decisions in a SHOP optimization are nonlinear. Thus, a linearization will not be optimal in any case, but a good approximation at high density of break-points (ref. Section 4.4).

Anyway, the goal with this example was to illustrate the value of commitment-flexibility in context of a price forecast. The price independent forecast bid, under the column *SHOP Forecast*, represents the benchmark used throughout this thesis when investigating the theoretical improvement potential for price forecasts, i.e. the maximum value of accounting for price uncertainty (stochastic model). It was expected in the methodology section that price-dependent bids would benefit from its flexibility, which generally speaking is the same as accounting for price uncertainty due to a multi-scenario price optimization. The price dependent linearization method has a potential improvement amounting to 2,715 EUR, and the price independent (based on same forecast) at 3,076 EUR, equal to a difference of 360 EUR.

The difference of 360 EUR is equal to 0.62 % of the optimal value of energy sale in the day-head market. Note that this value will vary from scenario to scenario, as you might be lucky with a price independent bid once in a while, and you will never know if a decision today may give positive-, or negative, ripple effects for the following days. For example, if you left more water in your reservoirs by making a bad decision since you expected lower prices than actual, and suddenly it turns out to not be a bad choice anyway since the price reached all-time high the following day, unexpectedly. Hence, it is the long term performance of different bidding strategies that is interesting. But the fact that price independent bids are a good benchmark for revealing maximal theoretical improvement potentials, remains as a valid and robust assumption.

9.2.1 Summary

This subsection will summarize the relevant findings in this report.

The river system's price sensitivity, defining the feasible solution space for theoretical improvement potentials. Average value calculated between maximum and minimum limits.

Table 47 - The average theoretical improvement potential for the feasible solution space (between tangent values) in EUR and % of spot sales

Case	Leirdøla		Vik		Røssåga	
Feasible Solution Space	5,531	0.7480%	9,322	1.4670%	58,113	1.7825%

The river system's seasonal variations. Average values of the price forecasts S2 to S8.

Table 48 - The average theoretical improvement potential for the seasonal variations, in EUR and % of spot sales

Case	Leirdøla		Vik		Røssåga	
High reservoir levels, January	353	0.0915%	453	0.0628%	414	0.0150%
Low reservoir levels, May	895	0.6738%	35	0.0187%	1,391	0.0582%
Medium reservoir levels, July	545	0.0823%	574	0.0993%	2,142	0.0927%
Average	**598**	**0.2826%**	**354**	**0.0603%**	**1,316**	**0.0553%**

The river systems analysed in the price volatility cases. Calculated as average values of the price scenarios S2 to S8.

Table 49 - Summary of the price volatility cases, average theoretical improvement potential in EUR and % of spot sales

Case	Leirdøla		Vik		Røssåga	
Low volatility, low price	0	0.0000%	127	0.0175%	109.155	0.0044%
Low volatility, high price	0	0.0000%	776	0.0957%	677	0.0180%
High volatility, low price	115	0.0247%	592	0.5330%	2,311	0.1136%
High volatility, high price	1,388	0.1877%	1,985	0.3124%	4,492	0.1352%
Average	**376**	**0.0531%**	**870**	**0.2397%**	**1,897**	**0.0678%**

The price areas analysed in the wind power production cases. Calcualated as average values from the price scenarios S2 to S8.

Table 50 - Summary of the wind production cases, average theoretical improvement potential in EUR and % of spot sales

Case	NO2		NO3		NO4	
Low wind production (26/7)	95,139	1.4382%	1,167	0.0318%	4,991	0.0515%
High wind production (24/12)	122,705	1.4989%	6,026	0.2491%	22,354	0.2748%
Average	**108,922**	**1.4685%**	**3,597**	**0.1404%**	**13,672**	**0.1632%**

9.3 OTHER ANALYSES

This section presents alternative analyses of different decision parameters, as well as the value of modelling a creek intake. The value of manual decision parameters are *certain values*, and not potential values like what we get from analysing income effect of stochastic variables like price and inflow.

The use of marginal costs as water values are assessed in light of seasonal couplings where the guiding from the long-term models can be relatively poor, e.g. before flood- and filling seasons. Then a cost-analysis of AGC is evaluated with a smoothing-function in SHOP (Norwegian: "glattefunksjon"). Followed by examples of short-term revision planning, and the creek-intake modelling.

9.3.1 Use of MC as WV

The goal with this section to look at the significance of price forecasts during different stages in the hydrological balance within a system. The use of marginal costs as water values will also be attempted upfront to reservoir flood and –filling. The different cases with respect to the reservoir level and future LT guiding are listed below:

- Friday, January 4th; prior to the reservoir tapping. Nearly full reservoirs and minimum inflow.
- Tuesday, May 7th; prior to the reservoir filling. Nearly empty reservoirs and inflow-dependent.
- Wednesday, July 10th; halfway into the filling season with large amounts of inflow.

Detailed optimization results are not presented in this Section, like the tables given in previous sections. Thus, the focus will be to present the market environment throughout the optimization period in SHOP by illustrating the spot price, price forecasts, and independent WV's provided by the LTM. A hypothesis will be drawn trying to imply whether the WV should be changed or not, and in what direction. Then a multi-scenario optimization of price will be ran, and the reservoir's MC collected from the optimization results. The MC will be used to see if it gives the same indications as the WV hypothesis; if the MC is lower, or higher, than the initial WV. Leirdøla will be used for this purpose, and a comparison of the significance of the price forecasts will be presented in the end of this section.

The spot price and average water values for the river systems are presented in Figure 84, Figure 85, and Figure 86 for the respective cases that were given an introduction above. The figures does also show a plot of the two selected price forecasts (S2 and S3) to indicate the LTM expectations.

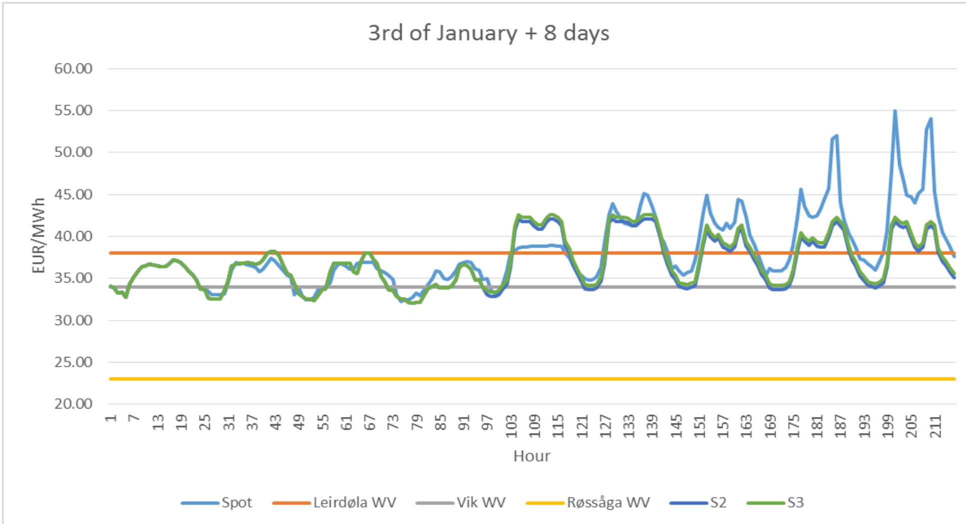

Figure 84 - Spot price, price forecasts, and average water values for January 3rd and 8 days beyond

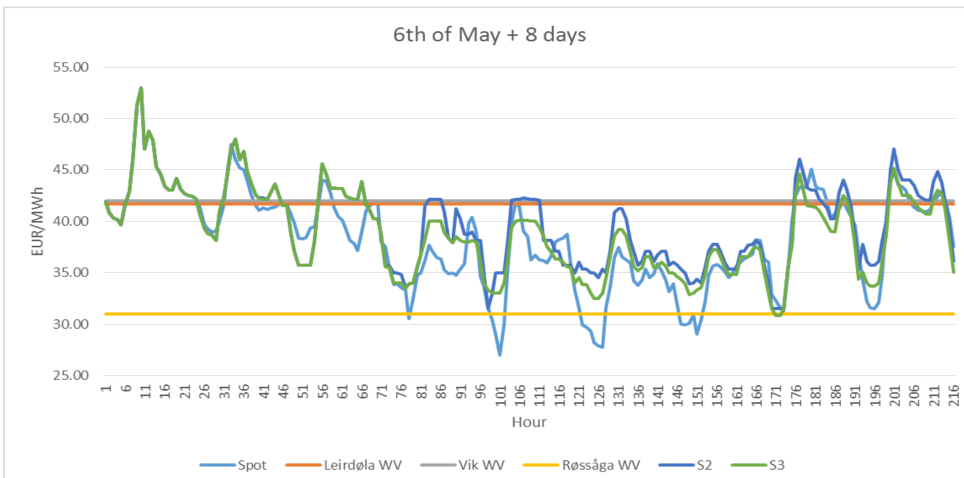

Figure 85 - Spot price, price forecasts, and average water values for May 6th and 8 days beyond

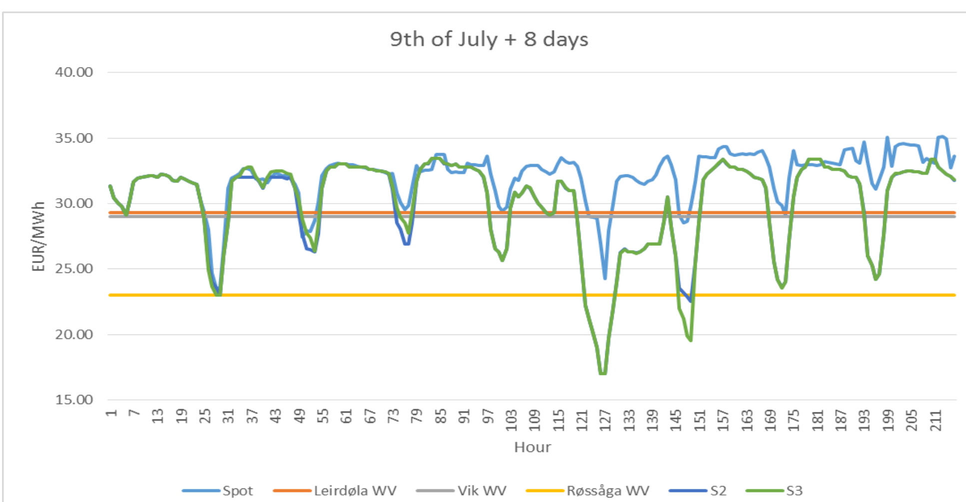

Figure 86 - Spot price, price forecasts, and average water values for July 9th and 8 days beyond

In the first case, the spot price increases more than the forecasts throughout the optimization period for January 4th, which could indicate that the WV's potentially should be increased. A multi-scenario optimization were executed to calculate the reservoir's average marginal cost with respect to different price scenarios deviating from the best price forecast available. The price scenarios were calculated with price forecast, S3, as reference, with constant deviations from the reference forecast, as illustrated in Figure 87.

The MC increases as the price level increase, which is logic since SHOP is most likely producing more as the price increase, hence less water left in the reservoir. One could for example weight the probability of the respective price scenarios to approximate a MC to be used as WV*. Regardless of the chosen probability, the estimated WV* would be higher than the initial WV. This is in accordance with our hypothesis. However, it would only provide a minor increase and it would most likely not affect the scheduled production.

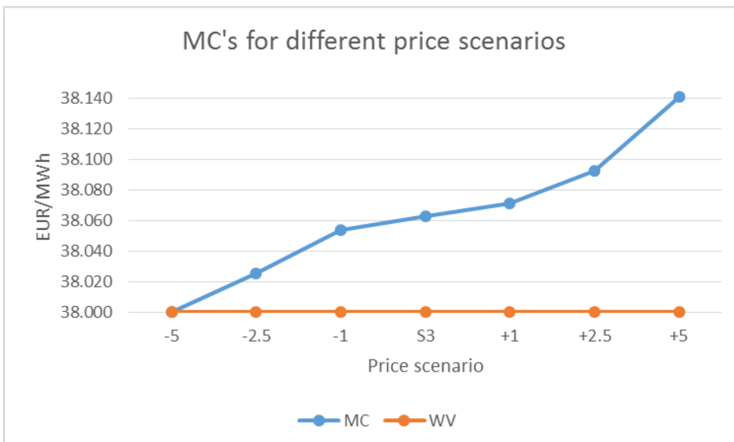

Figure 87 - Multi-scenario price optimization calculating respective marginal costs at Leirdøla, January 4th

The same case is analyzed for Røssåga river system, and the results are plotted in Figure 88. The same pattern that were observed for Leirdøla, is recognized for Røssvatn. Fallfoss however, does result in decreasing MC's as the price increase because of increasing production, hence increased inflow to Fallfoss from Øvre Røssåga. The MC's imply that the WV at Røssvatn could be increased.

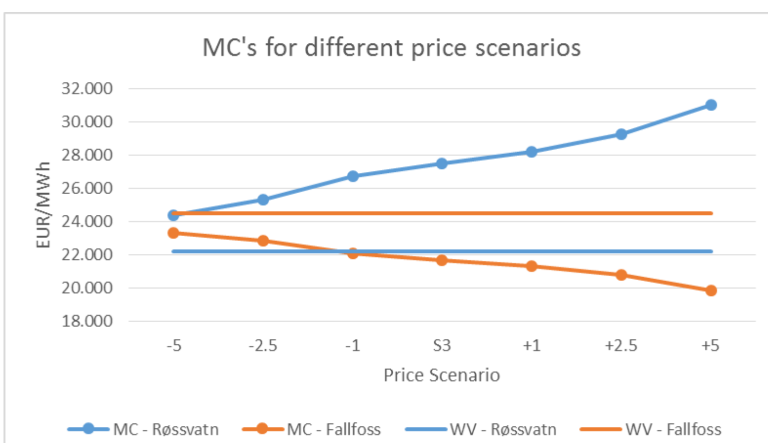

Figure 88 - MC calculations for Røssåga, 4th of January

Continuing on with 7th of May. The reservoir levels that day are relatively low. The price forecasts match the spot price-profile relatively good, but the spot price is however slightly lower on average, which could indicate that the WV's should be lower.

The multi-scenario optimization gave the following MC's depicted in Figure 89 for both increasing price levels (left plot), and increasing inflow level (right plot). The hypothesis about lowering the WV were not possible to indicate with the MC's. Anyway, note that the MC cost in the left plot increases significantly more for the same scenarios in Figure 87. Hence, the MC is now more sensitive to price variations than for the case with higher reservoir levels. The inflow scenarios were included to see if the price forecasts (and WV) could have been based on dryer weather forecasts, but it seems not to be the case.

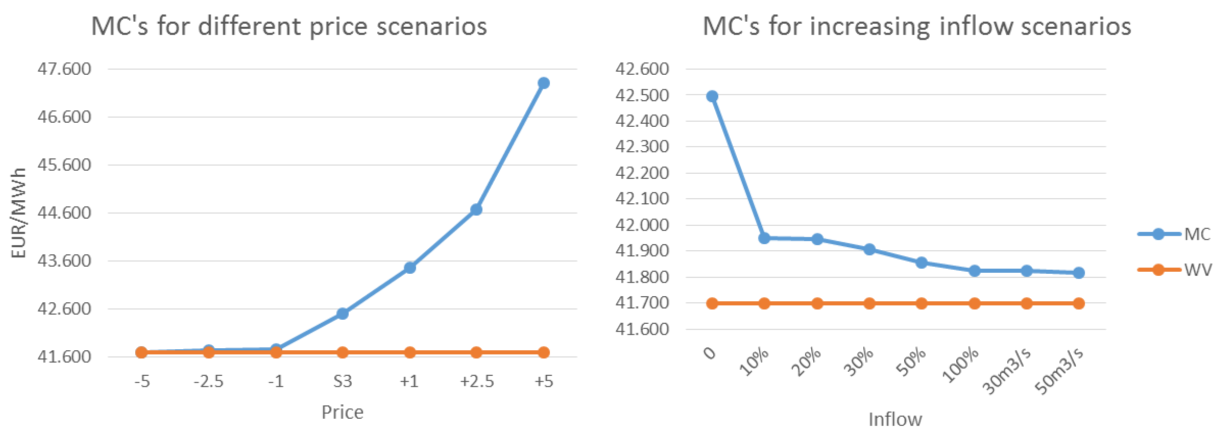

Figure 89 - Multi-scenario price (left) and inflow (right) optimization calculating marginal costs at Leirdøla, May 7th

As for Røssåga, the same pattern as previous case is represented here as well. But as one can see in Figure 90 the MC's are lower at Røssvatn during the negative price deviations, hence it could imply that the WV should be lowered as long as the price is lower than the +2.5 scenario. Røssvatn is by far the largest reservoir, thus also the dominating one when accounting for WV changes. The hypothesis about lowering the WV could be valid with respect to Røssåga.

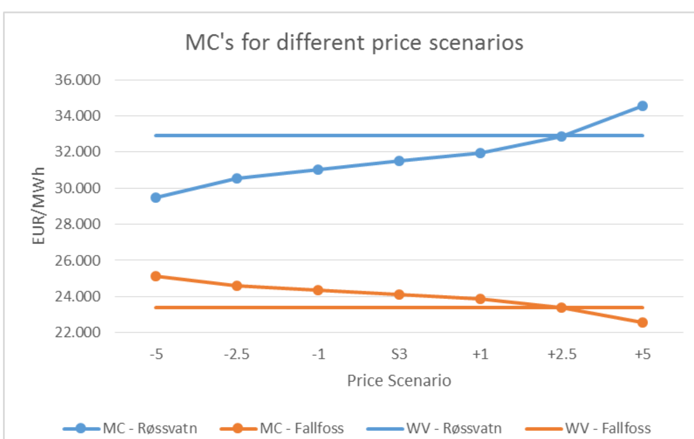

Figure 90 - Calculated MC's for Røssåga during 7th of May

At 10th of July the reservoir levels are filled up till about 60% of their capacity. The price forecasts are on average lower than the spot price-profile. The LTM may have predicted more inflow than actual, and the hypothesis is therefore that the WV should be slightly increased.

The MC is, as expected, increasing with respect to increasing price levels at Leirdøla. But the MC is now less sensitive to price changes, again, as the reservoir levels are relatively high and not that dependent on the inflow.

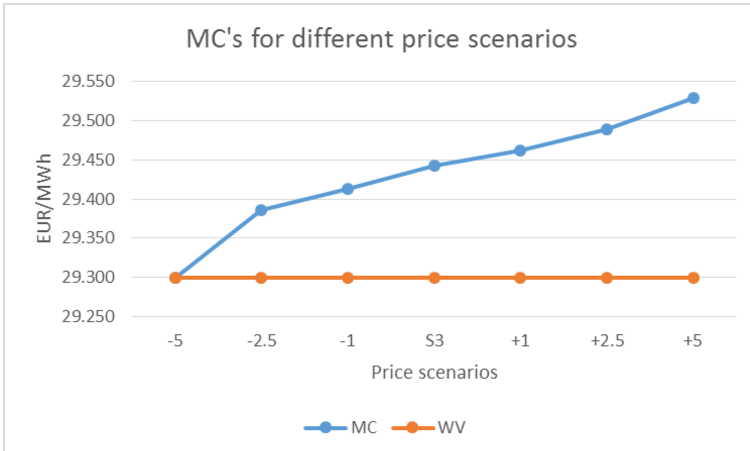

Figure 91 - Multi-scenario price optimization calculation marginal costs for Leirdøla, July 10th

Conclusion based on the calculated MC's:
It turned out to be difficult to use MC's from SHOP as an indicator for the LT-guiding, based on a price forecast as reference. The MC were also relatively identical to the WV, except from when the reservoir were nearly empty and especially sensitive to price variations. However, Røssåga showed clearer indications for the WV guiding, especially with respect to Røssvatn.

When the WV was expected to be lowered, then most of the calculated MC's around the priceforecast were weighted below the initial WV. The opposite was shown when the WV were expected to be greater, meaning that the weighted MC's was above the initial WV.

Significance of price forecasts at the respective cases:
The theoretical improvement potential for the price scenarios, at the respective dates given in the introduction to this section, is graphically presented as the percentage of the total sales from the reference scenario, which is the spot price. The results are illustrated for Leirdøla, Vik, and Røssåga in Figure 92, Figure 93, and Figure 94 respectively.

The results are presented like this to illustrate how small the potential improvements of a price forecast really are, with respect to the optimal values being sold to the market. The low- and high scenarios gives an idea of the economic loss in case of really poor forecasts, i.e. they indicate if the potentially poorest possible price forecast is above, or below the price level of the spot price.

S1 does naturally give 0% theoretical improvement potential as it represents the optimal scheduling. It is hard to see from the figures, but S2 and S3 gives the overall best forecasts, as usual. The theoretical improvement potential varies 0 % and 2 % for Leirdøla, 0 % and 0.20 % for Vik, and 0 % to 0.20 % for Røssåga. The feasible solution space is all over greatest for Røssåga.

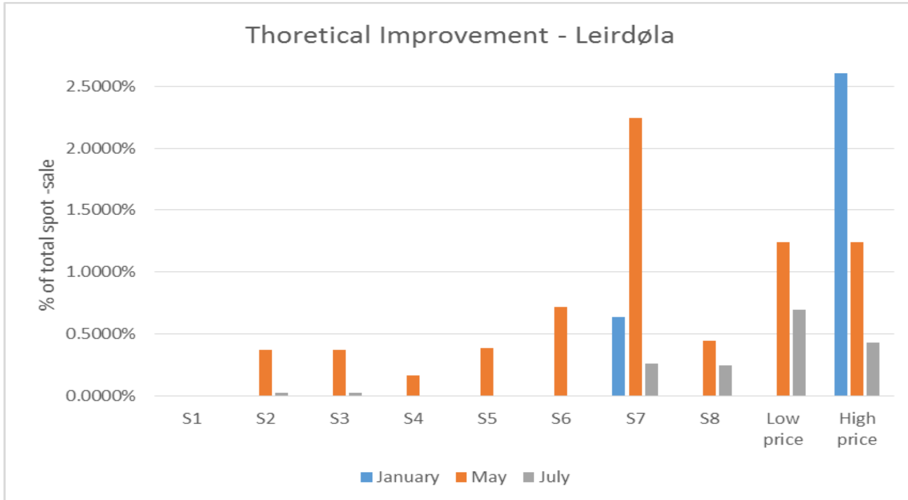

Figure 92 - Theoretical improvement potential for the price forecasts at Leirdøla

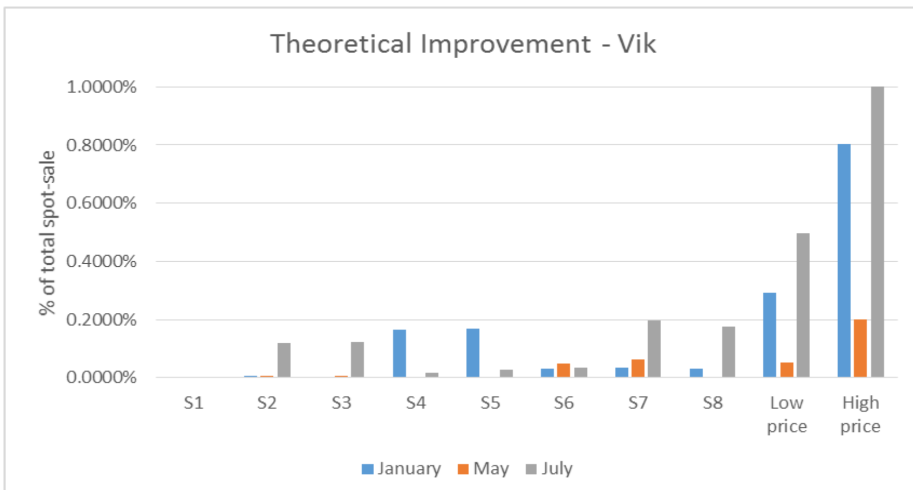

Figure 93 - Theoretical improvement potential for the forecasts at Vik

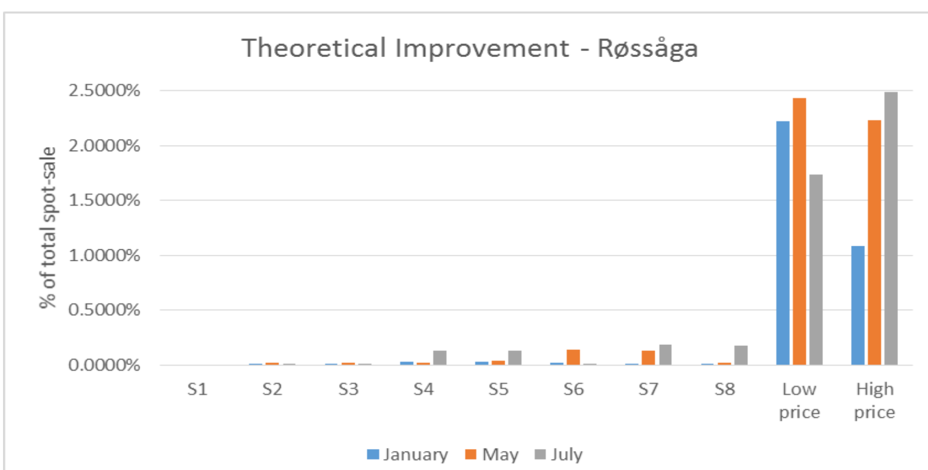

Figure 94 - Theoretical improvement potential for the price forecasts at Røssåga

9.3.2 The Cost of using AGC

This analysis is carried out for two river systems, and one price area. The river systems are diversified with respect to generation stations capacity and efficiency curve, i.e. stations with a flat efficiency curve giving a wide range of potential scheduling. Some stations have very “tuned/steep” efficiency curve, thus they either operate at maximum or minimum limit, and AGC would not be necessary. The latter assumption is illustrated with Svartisen in Figure 95, which is the largest station in Norway. The figure shows that the plan is already very smooth, and there is normally no need for AGC at similar stations like Svartisen.

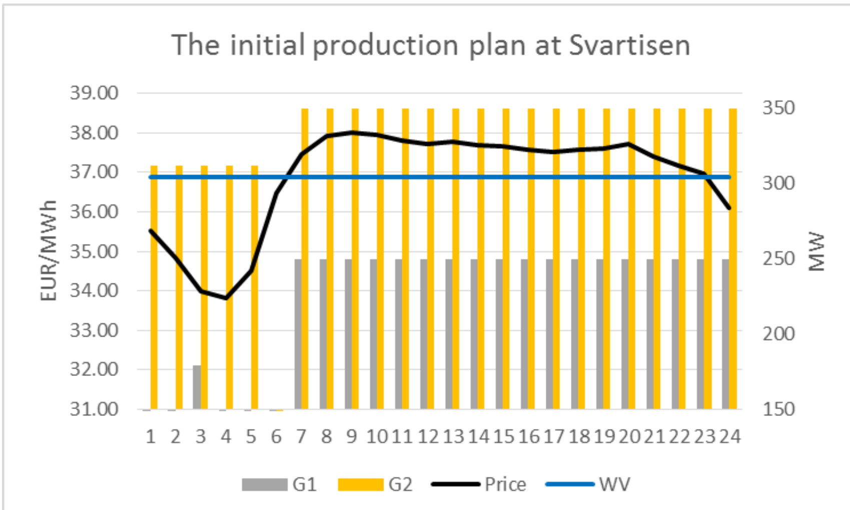

Figure 95 - Initial plan for Svartisen. AGC is not necessary.

The stations that are chosen for the cost analysis of AGC is Leirdøla (max 125 MW) and Øvre Røssåga (max 3x153 MW). The procedure is designed in such way that the AGC is implemented for day-ahead scheduling, meaning 24 hours. To provoke variance in the scheduled production, the water value is set equal to the average value of the price series used, within the respective day of AGC. The same price series, and water value, are for simplicity used at all the cases.

The price series, and water value, is depicted along with the initial production plan at Leirdøla in Figure 96. The initial production indicates that there could be implemented AGC that will smooth the scheduled production.

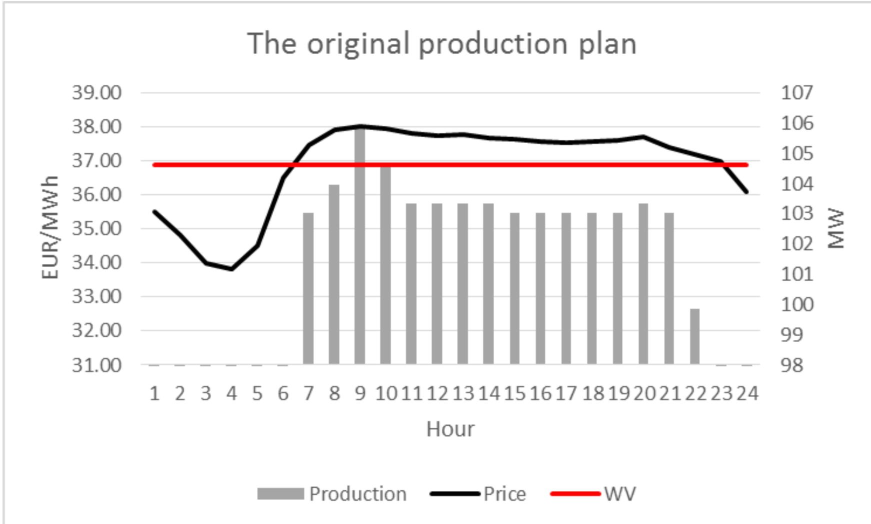

Figure 96 - Price, water value, and initial scheduled production at Leirdøla before implementing AGC

AGC costs at Leirdøla

AGC equal to respectively 2, 4, 6, 8, and 10 where implemented to the initial plan. This resulted in the following AGC-cost relationship depicted in Figure 97.

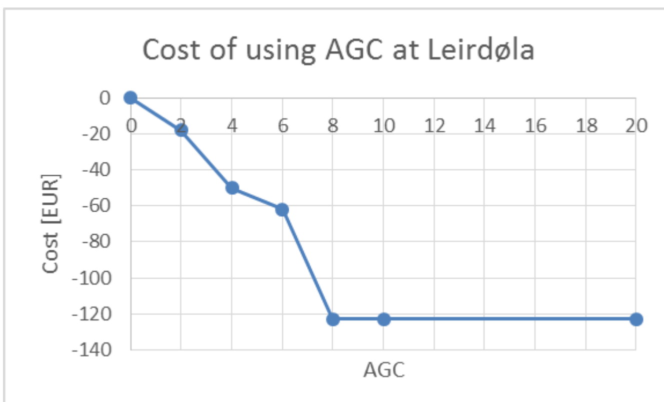

Figure 97 - The cost of using AGC at Leirdøla

AGC costs at Øvre Røssåga

Øvre Røssåga is assumed to be a good example, since there is usually more pressure at Nedre Røssåga and therefore less variations in the production.

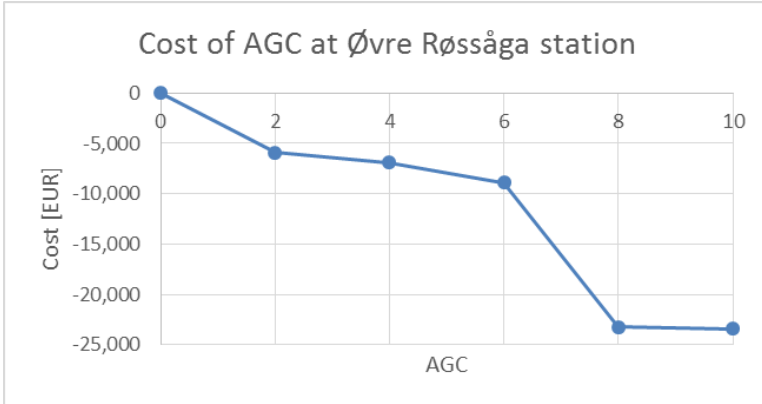

Figure 98 - The costs of using AGC at Øvre Røssåga

The AGC-cost pattern seems to be relatively similar for Leridøla and Øvre Røssåga. At less comprehensive variation of the AGC, the costs are almost the same. But at some point the AGC will include "too large" variations in generation, which will result in considerable deviations from the optimal scheduling in SHOP.

A yearly estimate of the costs are given in the table below. It is divided into a low-, base-, and high case amounting to the respective AGC values 2, 4, and 10. It is assumed that the AGC only will be implemented during weekdays (5 days a week) when the price profile potentially varies the most. The resulting values are given in EUR per year, based on the following assumptions:

- AGC-effective days during a year at Leirdøla: 5 days * 45 weeks = 225 days
- AGC-effective days during a year at Røssåga: 5 days * 50 weeks = 250 days

Eventual discount-rate is disregarded. This is only an example made for illustrating the potential costs on a yearly basis, which is calculated as AGC-efficient days multiplied with the respective AGC cost per day.

Table 51 - Yearly costs of using AGC [EUR] at Leirdøla and Røssåga. Low (AGC=2), base (AGC=4), and high case (AGC=10).

AGC case	Leirdøla	Røssåga
Low	-450	-1,483,500
Base	-900	-1,729,000
High	-27,675	-5,853,250

9.3.3 Short-term Revision Planning

This section will provide an example for short term revision planning. Revision planning is simply when to implement a revision, with respect to economic incentives. The goal with the revision is to avoid implementation when the expected income is high, and pursue revisions when the expected income is low. The example is carried out for:

- Leirdøla
    - Designed case with historical, average price profiles from Monday and 8 days ahead (equal to SHOP's optimization period).
    - Only one unit and minor flexibility

Leirdøla Station

This is a fictive case representing a simple river system, with an average price profile during the simulation period. The price profile is estimated based on data from 2013, and it starts at Monday 00:00 lasting 216 hours into the future (1 + 8 days, equal to the optimization period). The water value is calculated as an average value of the price series at the day being analysed. For example, if the planned revision is for a Tuesday, the water value is set to the average price that day. The price scenario, as well as an average value for the optimization period, is depicted in Figure 99. The markings in the figure shows some of the potential revision cases.

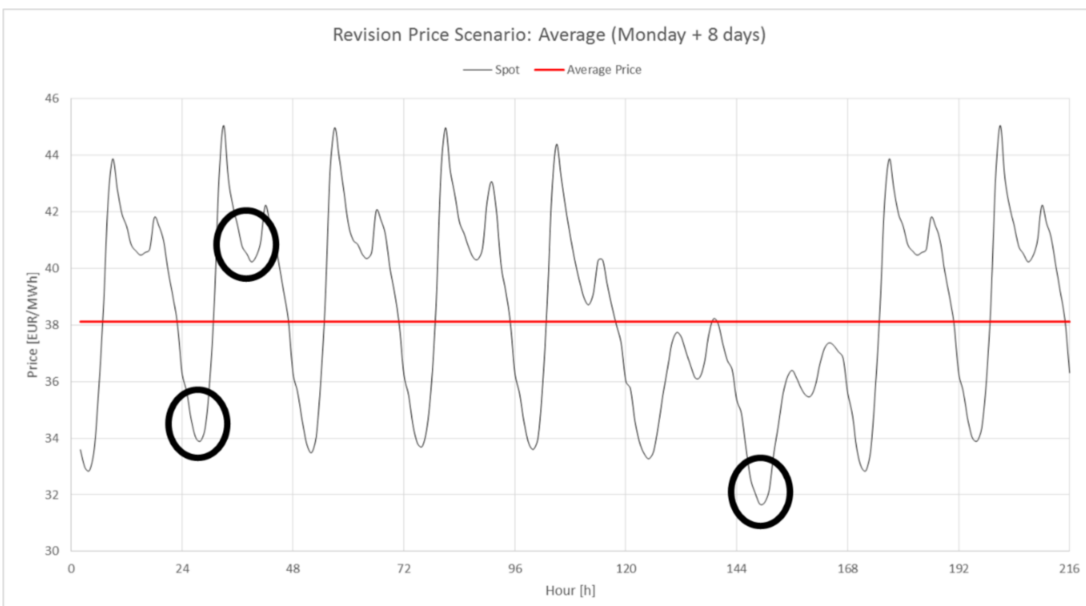

Figure 99 - Price scenario based on average day-profiles during 2013.

The revision cases are chosen to illustrate the costs of doing it during night, day-time, the whole day, and in the weekends. The resulting costs can for example be compared with the resource costs for the revision implementation, e.g. it is more expensive to hire people for a revision during the weekend, but the economic incentives in form of opportunity costs may be in favour of actually utilizing the weekend for revision when the price levels are lower (than for work-days). A summary of the cases, as well as the optimization results are listed in Table 52.

Table 52 - Cost analysis of revision planning

Scenario	Income	Cost	Sale	Startup costs	Reservoir value	ΔReservoir
No revision	7,781,209	0	449,092	2,940	7,335,057	0
Tuesday 02:00 – 06:00, 4h	7,781,209	0	449,092	2,940	7,335,057	0
Tuesday 12:00 – 16:00, 4h	7,779,371	1,839	426,653	3,430	7,356,148	21,090
Tuesday 13:00, 1h	7,780,357	853	444,332	3,430	7,339,455	4,397
Friday 12:00 – 16:00, 4h	7,779,928	1,281	431,905	3,430	7,351,453	16,396
Friday, 24h	7,777,768	3,441	385,840	2,450	7,394,377	59,320
Tuesday, 24h	7,776,175	5,034	377,909	2,450	7,400,716	65,659
Sunday 04:00 – 08:00, 4h	7,781,210	0	449,215	2,940	7,334,935	0

The resulting costs from Table 52 could be used to plan a revision. It is for example "cheaper" to implement a revision at Friday, compared with Tuesday. Note that Leirdøla only has one unit, hence the stations has limited flexibility to cover for the outage of one unit.

9.3.4 The value of modelling a creek intake

The physical effect of a creek intake can give increased pressure at a junction point in downstream in a tunnel. The result might be a reduced pressure drop in the tunnel. If the pressure drop decreases, the energy equivalent at the connected units will increase. This subsection will present an analysis of the income effect in SHOP if a creek intake is included in the model. Barduelva (Innset-Straumsmo) is used as an example, since it has a downstream creek intake in reality. An analogue illustration of this case is shown incFigure 100, with one reservoir, a junction point, and a generator.

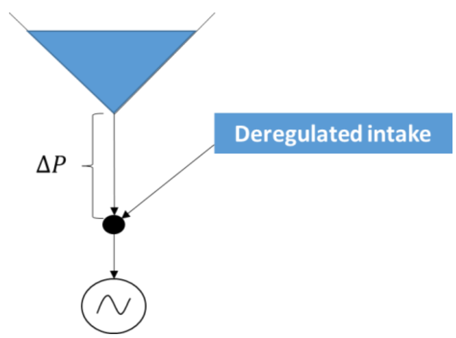

Figure 100 - Conceptual illustration of a deregulated creek intake

The river intake is not regulated, and it is therefore dependent on inflow to the catchment area. The operative model that Statkraft use is modelled in such way that all the short-term inflow in the catchment area is collected in the reservoir. In real life, this inflow will partly be stored in the reservoir, and some will flow directly in through the creek intake downstream of the reservoir. However, the hydrologists at Statkraft can provide estimates on have the inflow is shared between the reservoir, and the creek intake.

Inflow sharing-factor were used to simulate the following two scenarios:

1. 100% of the inflow stored in the reservoir. This is how it is modelled for operational purposes.

2. Hydrological sharing-factor were used to split the inflow into the creek intake (60 %), and the reservoir (40 %). This is the modelling that are being evaluated.

The estimated sharing factor given by the hydrologists at Statkraft were 0.301 for the creek-intake, and 0.222 for the reservoir. Hence, the following percentages of the inflow:

$$Inflow\ to\ creek\ intake = \frac{0.301}{0.301 + 0.222} = 60\%$$

$$Inflow\ to\ reservoir = \frac{0.222}{0.301 + 0.222} = 40\%$$

The same total amount of inflow to the system is identical for both scenarios, hence the difference in the objective functions is a result of the physical advantages with a creek intake. Different dates during the year are simulated to show that the effect of this modelling is dependent on the inflow.

Large amounts of inflow (June 6th)

The average inflow is 44.7 m3/s during the optimization period.

Scenario	Income	Sales	Start costs	End-reservoir	Penalty
1. Original	9,775,295	1,135,993	1,360	8,640,662	0
2. With creek intake	9,777,954	1,137,725	1,360	8,641,589	0
Difference	**2,659**	1,732	0	927	0

With very high price, thus very maximum production:

Scenario	Income	Sales	Start costs	End-reservoir	Penalty
1. Original	16,446,065	7,817,255	1,360	8,630,169	0
2. With creek intake	16,451,404	7,819,990	1,360	8,632,774	0
Difference	**5,339**	2,735	0	2,605	0

No Inflow (December 22nd)

The average inflow during the period of optimization is 1.4 m3/s.

Scenario	Income	Sales	Start costs	End-reservoir	Penalty
1. Original	23,854,544	1,320,917	920	22,534,547	0
2. With creek intake	23,854,855	1,320,859	920	22,534,916	0
Difference	**311**	-58	0	369	0

Moderate amount of inflow (June 11th)

The average inflow during this period is 20.5 m3/s.

Scenario	Income	Sales	Start costs	End-reservoir	Penalty
1. Original	20,351,017	948,651	11,660	19,414,026	0
2. With creek intake	20,354,268	952,072	11,660	19,413,856	0
Difference	**3,251**	3,421	0	-170	0

A comparison:

- High inflow
    - Normal station capacity: +2669 EUR
    - Max station capacity: +5339 EUR
- Moderate inflow
    - Normal station capacity: +3251 EUR
- Low inflow
    - Normal station capacity: +311 EUR

Assuming that the same modelling option yields for 1000 MW installed capacity in Statkraft's portfolio, and that the moderate inflow level is valid for 14 weeks per year, on average. Together with a weekly income effect about 3251 EUR/week, this will give a yearly income effect amounting to 350,108 EUR/year for the whole portfolio.

$$\frac{1000}{130} \cdot 3251 \frac{EUR}{week} \cdot 14\ weeks = 350\ 180\ EUR$$

10 CONCLUSION

This thesis investigates the true economic potential of different decision parameters related to short-term hydropower scheduling, where price uncertainty is the main focus. The goal is to quantify the maximum theoretical improvement potential of price forecasts, hence also the feasible potential of using a stochastic model. A deterministic model, SHOP, is used to address this scope of work. The significance of price forecasts are measured through income effects with SHOP, where historical day-ahead bids are established as price independent to optimize comparative scheduling with respect to an optimal reference value, i.e. the actual spot price.

Theoretical improvement potential is limited by the physical capacity and flexibility of the system (price area, river system), and tangents when the price forecast that are being measured, deviates more than a certain limit from the reference price. These limits (upper and lower) varies with respect to seasonal characteristics, and are determined by the volume sold (or not sold) above (or below) the optimal spot-volume. It is shown that the potential improvement is limited when the reservoir levels are extremely low, or high, hence the system operates at its limits (min or max). In such cases it can be seen that the price forecasts often has no value, and that the potential improvement therefore is nearly 0 %.

The conclusion is that price forecasts has more impact on flexible systems that rarely reach their limits, and periods with low probability for exceeding limits. The theoretical, *feasible improvement potential* for three different river systems, diversified with respect to flexibility and capacity, varies from 0.7480 % to 1.7825 %, with respect to the optimal spot-volume sold in the market. The lowest improvement represents the reservoir with the lowest capacity, and the highest potential improvement represents the river system with the largest capacity. Moreover is the potential improvement of *operative price forecasts* shown to be minimal, spanning from 0.0531 % to 0.2397 %, and strongly dependent on price volatility and price levels. The price areas reports improvement potentials between 0.1404 % and 1.4685 %, where NO2 and NO3 has the greatest-, and lowest-, improvement potential, respectively.

Inflow uncertainty is illustrated, and compared, with price uncertainty for a medium-sized river system. It is shown that as long as the system has enough capacity for storing the expected inflow, it will not affect the scheduling, nor the income. But when the water balance is near its higher limits, hence also exposed for spillage risk, the inflow may impact the scheduling due to calculations of forced production. In the latter case, the feasible, potential improvement for inflow variation amounted to 0.6858 %. The feasible potential of price variations accounted for 1.2169 %, as a comparison. Note that extreme price scenarios are more likely to happen, than the extreme inflow scenarios used in this analysis (up till 100 m^3/s at Leirdøla).

The report does also highlight the use of SHOP to evaluate long-term strategies, especially with respect to water values. During periods when the market is in energy surplus, or deficit, SHOP can be used to analyze the maximum-, or minimum-, contribution to the sell side in the power market. Due to the level of detail in the STM, it can potentially reveal e.g. forced production that not were accounted for in the LTM, hence the water value should be increased, and one could therefore expect an increasing price trend in the nearest future.

Furthermore is calculations of marginal costs with SHOP been used as an indicator for water value adjustments, especially upfront to flood- or inflow seasons where the long-term guiding is sensitive to short-term decisions and weather. The MC calculations where based on multi-scenario price optimizations to account for price uncertainty, and the weighted marginal costs used as indication for up- or down regulation of the WV. For example if the weighted MC were lower than the WV, it could indicate that the water values form the LTM were set too high.

However, the main essence from the conclusions in this report is that price forecasts has less impact on short-term scheduling than one might think. The potential income improvements with respect to the spot price is limited, and compared with the optimal volume sold in the market the potential can become nearly negligible. When evaluating stochastic inflow or price, it is shown that inflow is less influential than the price forecasts, since it only impact systems who reach its limits (poor degree of regulation).

10.1 FUTURE WORK

It is recommended to expand the sample for the statements made in this report, which is relatively scarce but still sufficient enough to make a point. An implementation of a script would be preferred, that can be programmed to run several optimizations for a given system and time interval. The script would have to import new time series (price) at each date optimizing a price independent day-ahead scheduling. The output from the script could be something like the tables presented throughout this report.

Moreover, the analysis should also be implemented for operational purposes over a longer period of time. One could for example measure the different bidding strategies, price independent, SPOTON, and price dependent with SHOP as well. An operative analysis over a longer period of time would give the best benchmark results, as it captures positive (and negative) coincidences over time. One could for example make a poor decision that suddenly turned out to be not so bad anyway.

It would also be interesting to arrange an empirical study that categorizes different market conditions, e.g.; what is a normal price profile? What is an extreme profile? Weekdays, weekends, and month of the year, to evaluate the significance of different decision parameters within these kind of categorizes.

Finally, a similar study as this one, but with more focus on dynamics. Meaning, for example cooperation possibilities of hydropower and wind power (Vardanyan, 2011), trading bad decisions back in the intraday market, and so on.

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APPENDICES

APPENDIX I – FORMULAS AND CLARIFICATIONS

Degree of regulation:

$$R = \frac{Maximum\ reservoir\ volume\ [MWh]}{Average\ annual\ inflow\ [MWh]}$$

Cut sets:

$$\alpha \leq \alpha^{*i} + \left(\mu^{*i}\right)^{T} (x_{N_{sh}} - x_{N_{sh}}^{*i})$$

Utilization time

$$T_u = \frac{Q_{yr}}{P_{max}} \quad [h]$$

$$T = \frac{Q_{yr}}{8760 \cdot P_{max}} 100 \quad [\%]$$

ARMA and GARCH

ARMA is a combined autoregressive (AR) process with a moving average (MA) of e.g. a time series. The MA-model is a linear combination of *white noise*:

$$y_t = \mu + \theta u_{t-1} + u_t$$

Where the *white noise* is defined as a process with no obvious structure. The ARMA model is a good fit for electricity prices since commodities tends to move along their equilibrium (mean-reverting) in the long-run.

The Generalized AutoRegressive Conditional Heteroscedastic (GARCH) model has a conditional variance that is dependent on the previous step's lag (residual and the residual's variance).

Source: Florentina, 2013

Standard Deviation:

A measure of the dispersion of a set of data from its mean. The more spread apart the data, the higher the deviation. Standard deviation is calculated as the square root of variance.

Source: www.investopedia.com, 13.03.2014

BID CURVE AND ELECTRICITY PRICING:

Figure 101 is an example of how a spot market supply-curve can look like. It is called a bid curve, due to its arrangement of sell bids received from the producers. The lowest bids gets first priority, and are therefore aggregated in ascending order with respect to quantity. For instance, if the demand is 16,000 MWh/h the clearing price at that point will be about 30 EUR/MWh. All the sell bids to the left gets cleared, and all the sell bids to the right gets rejected.

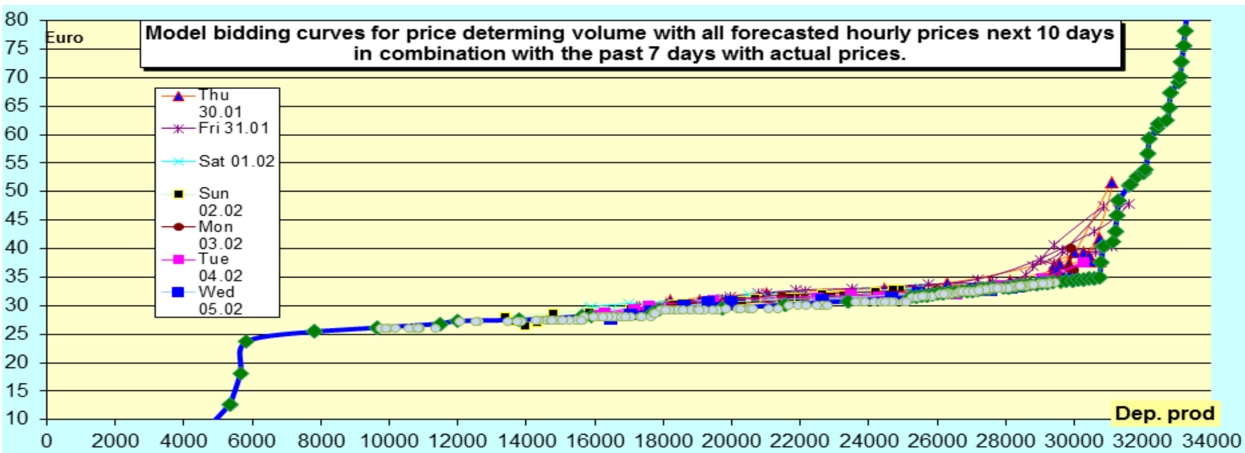


Figure 101 - Bid-curve at the power market (Markedskraft, 2014)

Note that the development of the supply curve is very steep after about 30,000 MWh/h. This is typically coal-, gas-, and oil producers with higher marginal cost. At lower marginal costs, the left part of the curve, is often characterized by wind-, solar-, bio-, hydro-, and nuclear sources. A generalized example is given in the Figure 102:

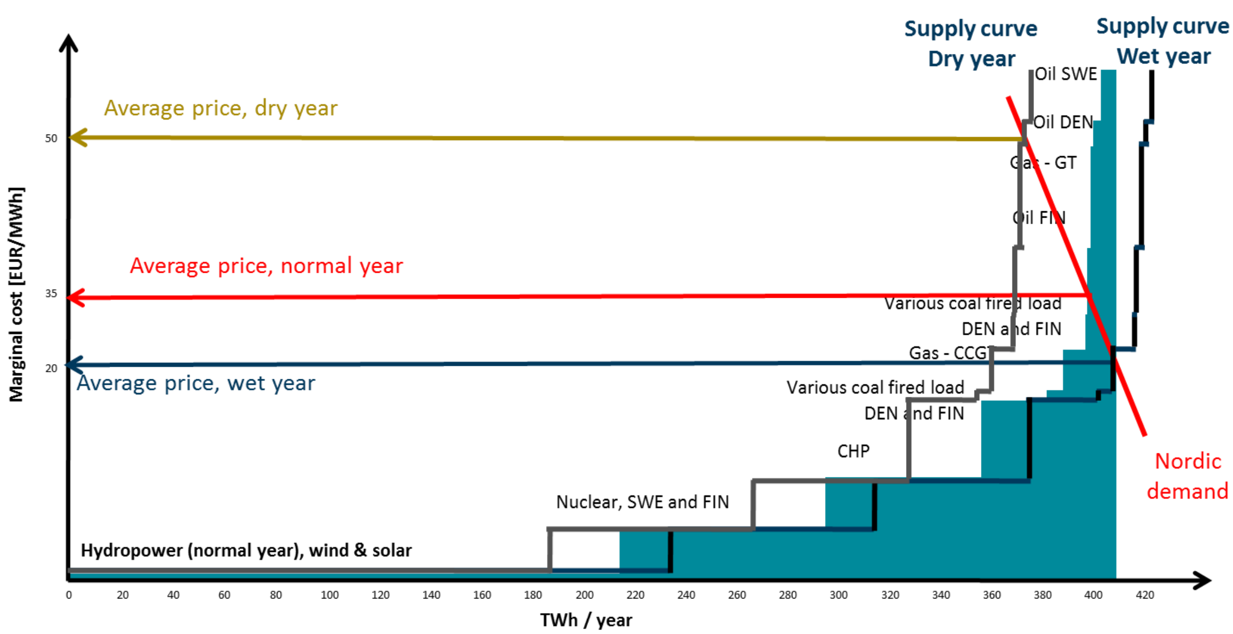


Figure 102 - Price equilibrium between supply and demand (Statkraf, 2013)

The generalized figure of the bid-curve can be used to illustrate the pricing of electricity in the Nordic market. The supply curve reminds us of the bid-curve, with MC of generation in ascending order. Since the hydropower generation represents about 51% of the production at Nord Pool, the average price during a year is highly dependent on the availability of hydropower. The figure illustrates supply-curve-shifts with respect to the hydrological balance, respectively a dry- and wet year. Large variations in inflow can cause Nordic hydropower production to vary about +/- 40 TWh per year.

A dry year results in a negative supply shift for hydropower to the left (from a normal year). The demand is relatively inelastic (and may even have a steeper curve than illustrated), and the supply curve will intersect the demand at a higher price than for an average year. Additionally, Norway will import a lot from Germany, The Netherlands, and Poland (Statkraft, 2013).

On the other hand, a wet year will provide more hydropower supply and give a positive supply-shift to the right. This gives a lower price than average.

The hydrological balance is therefore a major price driver for electricity in the Nordic, which will be discussed more in the next paragraph.

Price drivers in the Nordic

The prices on internationally traded energy commodities as coal, oil, gas, and CO_2 can fluctuate substantially and will instantly influence the marginal costs of thermal capacity in the market. This will change the shape of the Nordic supply curve, and hence also the Nordic power prices.

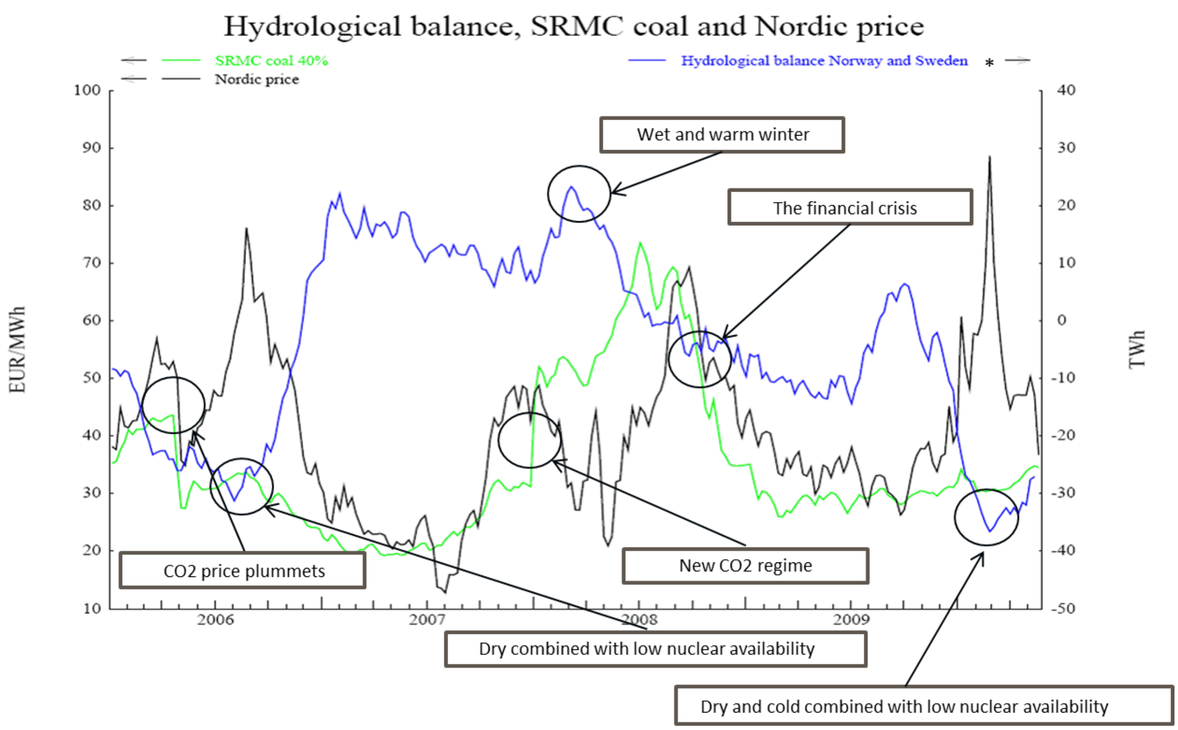


Figure 103 - Price drivers in the Nordic power market; Hydrological balance and SRMC coal (Statkraft, 2013)

The graph gives a good overview of the key elements in the price setting in the Nordic region. When the hydrological balance is close to normal, Nordic prices closely follow the short run marginal cost (SRMC) of a 40% efficiency coal plant. During periods when the hydrological situation is far below or way above the normal level, the Nordic prices are more decoupled from coal- and CO_2 prices.

The reason for this pattern is that the hydropower producers need to use a certain amount of water every year depending on the hydrological situation, otherwise they must spill water. To use enough water they need to bid in their power at a price level lower than competing thermal plants in enough hours during a year. That is why they can bid in their water at prices higher than thermal SRMC when the hydrological balance is weak and still get out the wanted amount of water. On the other hand, in wet periods they will produce at prices below SRMC to be sure they use enough water.

There are of course also many other important factors in the Nordic price formation, such as oil-, gas-, and aluminum prices. As well as the availability of transmission lines and economic situation (demand).

APPENDIX II – MARKET DATA, 2013

This appendix summarize some fundamental explanations and drivers for the electricity price at Nord Pool Spot during the year 2013.

TOTAL PRODUCTION AND GENERATION MIX IN THE NORDIC MARKET

The total production in in Norway, Sweden, Finland, Denmark, Estonia, Latvia and Lithuania amounted to 397 TWh. Sweden is the largest producer followed by Norway and Finland.

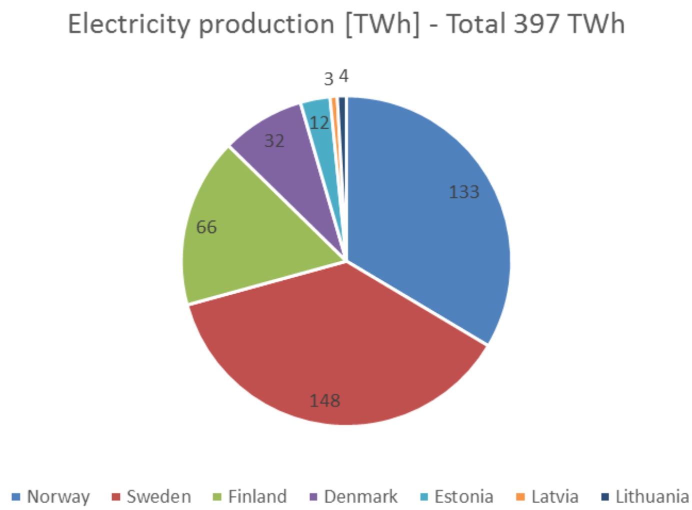


Figure 104 - Electricity production from the Nordic countries amounted to 397 TWh during 2013 (Nord Pool, 2014)

The generation mix is dominated by hydropower. Note that the data is old (2011) and it would be realistic to assume a minor decreased share of nuclear and fossil, in addition to an minor increase of renewables like solar and wind.

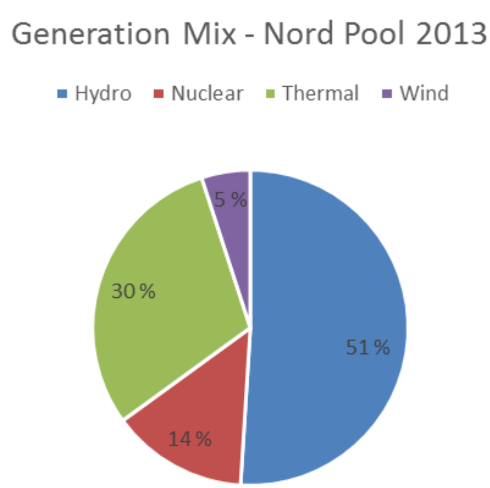
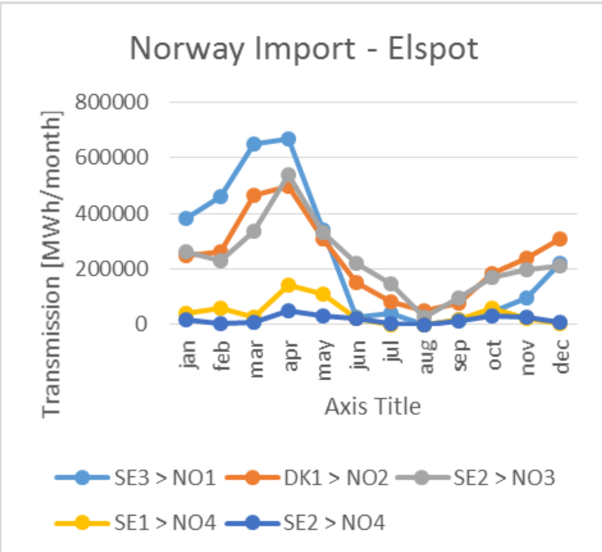


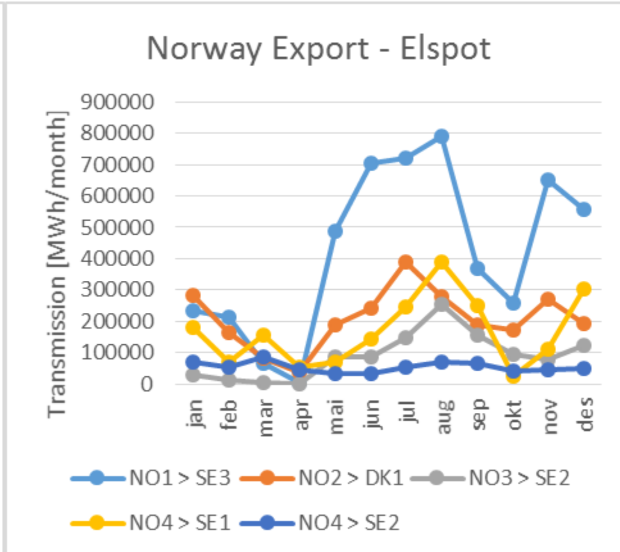
Figure 105 - Total generation mix at Nord Pool, year 2013. (Statkraft, 2013)

POWER EXCHANGE BETWEEN NORWAY AND NEIGHBORING COUNTRIES

An overview of exchanged market volumes is given for Elspot and Elbas. It is meant as a supplement for explaining eventual price shifts, and –variations.

Exchange at the day-ahead (Elspot) market within Nord Pool



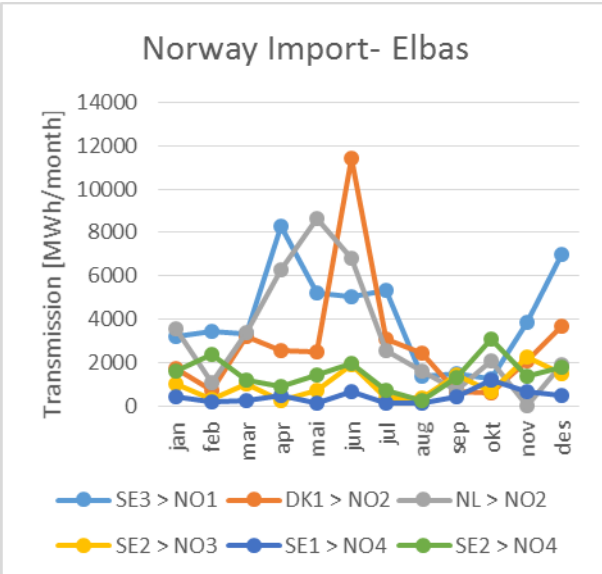


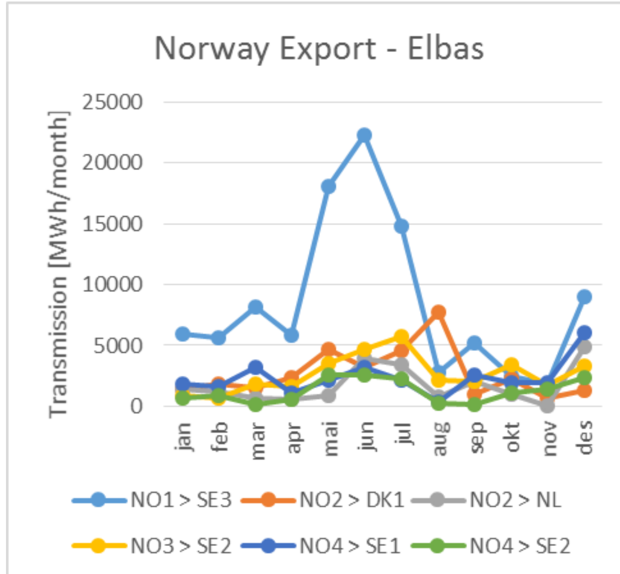
Source: Nord Pool Spot, 2014

The net export at Elspot to neighboring countries is low during the winter season, and high during the summer season.

Month	Export	Import	Net Export [GWh/Month]
jan	791	953	-162
feb	512	1 018	-506
mar	396	1 490	-1 094
apr	143	1 898	-1 755
mai	864	1 121	-257
jun	1 214	438	776
jul	1 556	274	1 282
aug	1 782	78	1 704
sep	1 029	219	810
okt	588	495	94
nov	1 153	584	570
des	1 225	747	478

Exchange at the intra-day (Elbas) market within Nord Pool:





The net export to neighbouring countries at Elbas is negative during April and November, and positive elsewise. The exports are highest during the summer.

Month	Export	Import	Net export [GWh/month]
jan	12,1	11,6	0,5
feb	11,8	8,2	3,6
mar	15,6	12,4	3,2
apr	12,1	18,7	-6,6
mai	31,8	18,7	13,1
jun	39,9	27,9	12,0
jul	32,8	12,2	20,6
aug	14,0	6,2	7,8
sep	13,0	6,2	6,9
okt	12,2	8,9	3,3
nov	7,6	10,2	-2,6
des	26,8	16,5	10,3

Elspot exchange with NL:

The NO2 – NL transmission cable is one of the most utilized connections. As seen by Figure 106 the cable is net exporting throughout the year, but less during the winter season. This observation is included to discuss eventual associations with the wind power utilization in Denmark, or Germany.

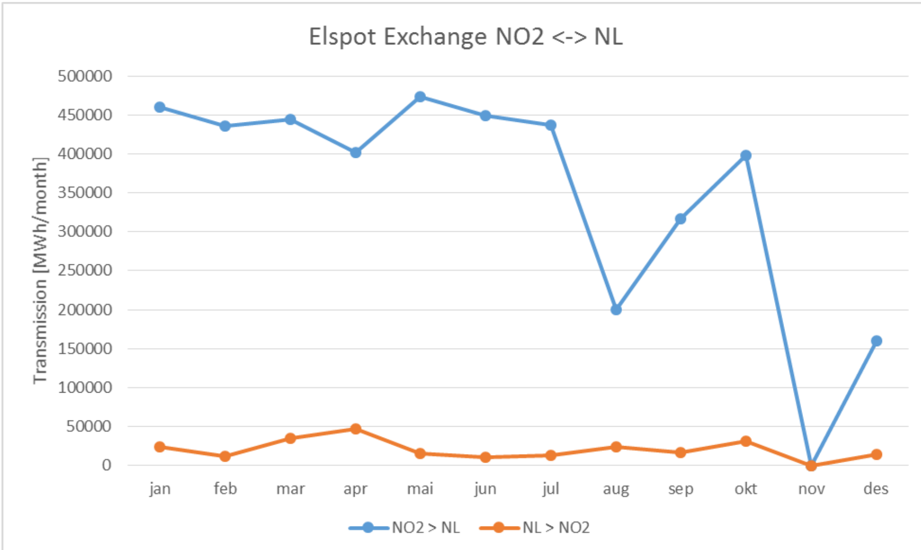
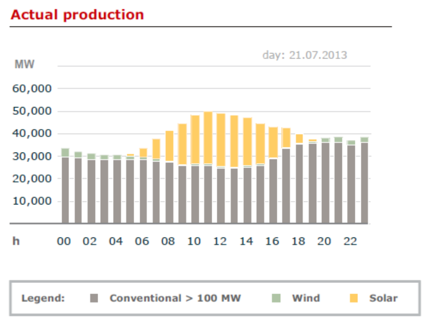


Figure 106 - Elspot exchange with the Netherlands from Norway

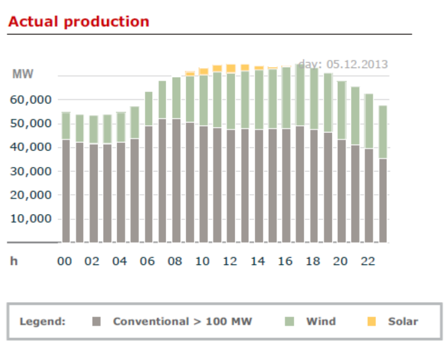
EXTREME WIND- AND SOLAR SCENARIOS IN GERMANY

Due to difficulties of collecting data for wind and solar at Nord Pool, then Germany was considered as a good benchmark. Especially regarding seasonal characteristics. Some extreme scenarios at EEX is presented here in the appendix.

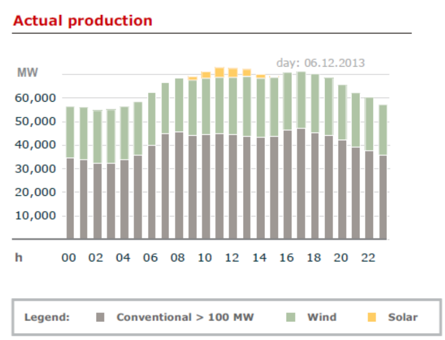


- Solar: max. 24.0 GW at 13:30 (+2:00); 204 GWh
- Wind: max. 3,7 GW; 34 GWh
- Conventional: max. 36,3 GW; 710 GWh

Figure 107 - Maximum solar power- and energy production: Sunday 21st of July, 2013 (Burger, 2014)



- Solar: max. 3.6 GW; 16 GWh
- Wind: max. 26.3 GW at 18:15 (+1:00); 485 GWh
- Conventional: max. 52.0 GW; 1130 GWh



- Solar: max. 4.0 GW; 19 GWh
- Wind: max. 25.5 GW; 563 GWh
- Conventional: max. 47.1 GW; 1012 GWh

Figure 108 - Maximum wind power- (GW, left fig.) and energy (GWh, right fig.) production at respectively Thursday 5th of December, and Friday 6th of December, 2013 (Burger, 2014)

INFLOW AND RESERVOIR FILLINGS IN NORWAY

The accumulated inflow (GWh/week) were very low during the first months of 2013. This may be one of the reasons for the high spot prices during that period of time. After the snow melting period in March/April the reservoir inflow increased to, and above, their average value.

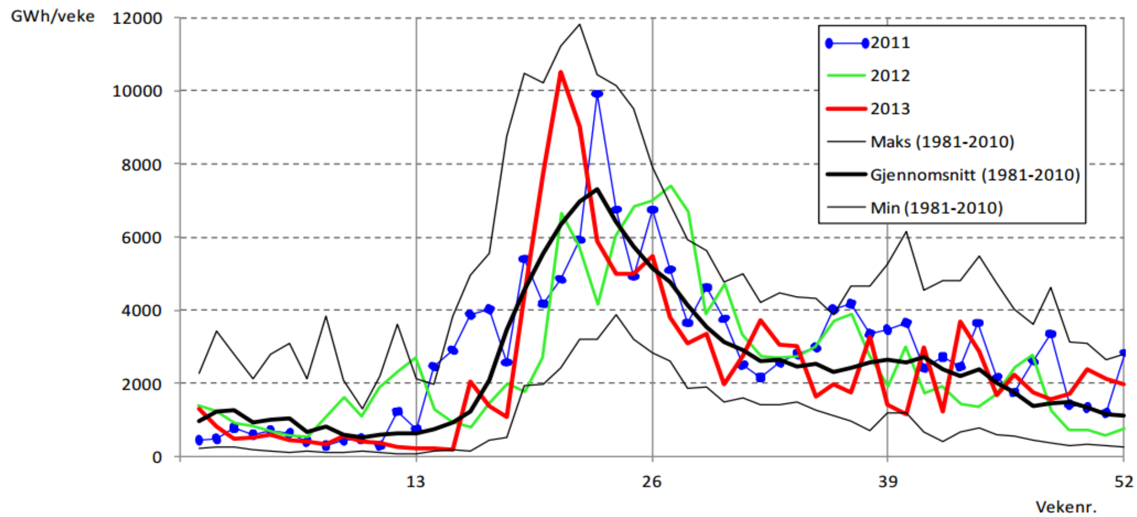


Figure 109 - Inflow in Norway during 2011, 2012 and 2013. The graph includes maximum-, minimum and average inflow observed in the period between 1881 - 2010. (NVE, Q4 2013)

Due to the lack of inflow (dry period) the first month we can see that this is reflected in the reservoir fillings (100% = 84.3 TWh), which were below average until late May.

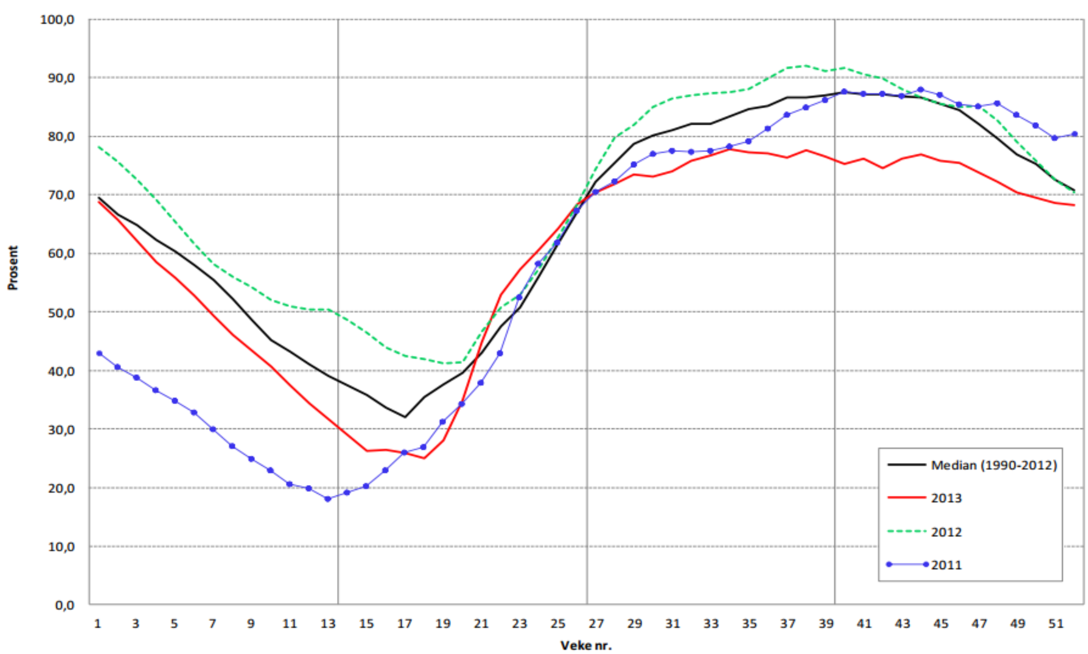


Figure 110 - Reservoir filling in Nowegian hydropower reservoirs during 2011, 2012 and 2013. 100% on the vertical axis equals 84.3 TWh. The graph includes a median filling observed between 1990 and 2012. (NVE, Q4 2013)

COAL-, GAS- AND CO2 PRICES

The figure below is an index for the price development on coal that is imported into northwest Europe. The coal price decreased about -10% during 2013 due to oversupply, especially in USA, after the shale-boom the recent years. 1 ton coal equivalent = 8.141002 MWh.

Figure 111 - Coal price [USD/ton] API 2. The API 2 index is the benchmark price reference for coal imported into northwest Europe. (NVE Q4 2013)

Next figure shows the price development for gas in the UK, Belgium and Netherlands. The gas price increased about 25-30 % during 2013.

Figure 112 - Gas price [NOK/MWh] in United Kingdom (NBP), Belgium (Zeebrugge) and the Netherlands (TTF) from 2011 to 2013. (NVE Q4 2013)

The CO2 emission rights has collapsed the recent years but seems to stabilize now as the volume was decreased in 2013. During that year the CO2-price had a flat positive development around +10 %.

Figure 113 - CO2 emission rights [EUR/ton] in the EU ETS (Emission Trading System). EUA-mm-yr = European Union allowances for a specific month and year of settlement. (NVE Q4 2013)

DOCUMENTATION OF PRICE AND VOLUME

Documentation of the observations given in Section 6.5.

INTRADAY SPOT PRICE

Largest decrease in spot			
Date	Minimum	Maximum	Standard deviation
23.06.2013	-73,46 %	144,95 %	44,52 %
21.03.2013	-60,28 %	39,74 %	19,02 %
22.06.2013	-59,07 %	72,20 %	29,84 %
24.01.2013	-48,03 %	34,99 %	14,75 %
30.06.2013	-41,59 %	57,21 %	17,06 %
Largest increase in spot			
Date	Minimum	Maximum	Standard deviation
23.06.2013	-73,46 %	144,95 %	44,52 %
22.06.2013	-59,07 %	72,20 %	29,84 %
30.06.2013	-41,59 %	57,21 %	17,06 %
02.04.2013	-34,74 %	55,73 %	16,03 %
16.06.2013	-28,47 %	51,35 %	14,63 %
Largest standard deviation			
Date	Minimum	Maximum	Standard deviation
23.06.2013	-73,46 %	144,95 %	44,52 %
22.06.2013	-59,07 %	72,20 %	29,84 %
21.03.2013	-60,28 %	39,74 %	19,02 %
30.06.2013	-41,59 %	57,21 %	17,06 %
02.04.2013	-34,74 %	55,73 %	16,03 %
Smallest standard deviation			
Date	Minimum	Maximum	Standard deviation
31.03.2013	0,00 %	0,00 %	0,00 %
24.03.2013	-1,66 %	2,52 %	1,06 %
03.11.2013	-2,27 %	1,92 %	1,06 %
30.03.2013	-3,23 %	2,67 %	1,10 %
17.03.2013	-1,81 %	3,30 %	1,17 %

MAX/MIN AVERAGE SPOT PRICE

Min		**Max**	
Date	Price	Date	Price
22.06.2013	17,5	08.04.2013	58,5
23.06.2013	19,2	02.04.2013	56,4
30.06.2013	26,0	21.03.2013	56,4
24.12.2013	27,3	24.01.2013	55,9
22.12.2013	27,7	23.01.2013	54,2

PRODUCTION & CONSUMPTION

More production than estimated		
Date	dPro	dCon
06.12.2013	-20243	13539
05.12.2013	-15228	13298
28.04.2013	-13572	-2854
20.05.2013	-12150	-2462
03.05.2013	-11150	-8481
Less production than estimated		
Date	dPro	dCon
16.12.2013	23559	21559
27.10.2013	20949	2139
02.01.2013	18989	-29252
29.10.2013	18491	2312
22.07.2013	14465	5245
More consumption than estimated		
Date	dPro	dCon
02.01.2013	18989	-29252
14.01.2013	3872	-20075
01.02.2013	4313	-19345
21.05.2013	-487	-19097
15.01.2013	-3002	-17038
Less consumption than estimated		
Date	dPro	dCon
17.05.2013	-4070	29405
24.12.2013	-1366	24882
23.12.2013	6237	22861
16.12.2013	23559	21559
18.05.2013	-9094	17662

NORD POOL WIND PRODUCTION

Minimum wind production		
Date	Wind NO	Minumum NP
26.07.2013	1 207	6 539
25.07.2013	992	7 038
27.07.2013	1 078	9 823
12.09.2013	1 854	11 835
13.09.2013	2 529	12 202
Maximum wind production		
Date	Wind NO	Maximum NP
24.12.2013	9 129	172 165
28.11.2013	10 194	167 595
21.12.2013	7 297	162 259
01.12.2013	9 893	159 317
06.12.2013	7 247	158 978

UP- & DOWN REGULATION PRICE

Date	Spot	Up	Down	Price deviation
Most negative deviation from spot				
Date	Spot	Up	Down	Price deviation
02.04.2013	56,38	56,75	41,03	-15,35
17.01.2013	53,44	53,64	38,57	-14,82
21.03.2013	56,36	56,36	41,58	-14,78
24.01.2013	55,90	58,36	42,01	-11,95
08.04.2013	58,54	58,60	47,89	-10,63
Most positive deviation from spot				
Date	Spot	Up	Down	Price deviation
16.01.2013	51,11	87,60	49,10	35,48
13.03.2013	50,12	75,40	49,70	25,28
14.03.2013	53,46	76,87	47,91	19,01
11.01.2013	41,82	56,90	41,32	14,59
12.04.2013	53,37	65,01	53,34	11,64
Smallest deviation from spot				
Date	Spot	Up	Down	Price deviation
04.07.2013	33,12	32,70	31,46	-1,24
19.12.2013	31,21	31,39	30,36	-1,02
18.12.2013	33,51	32,64	32,05	-0,59
07.07.2013	28,79	29,30	28,86	0,51
29.11.2013	36,76	37,61	36,15	0,85

Platts 2013 Analysis of Germany:

http://www.platts.com/latest-news/electric-power/london/analysis-german-2013-wind-solar-power-output-26598276

Wind Westerlines:
http://en.wikipedia.org/wiki/Wind

APPENDIX III – RIVER SYSTEMS PER PRICE AREA

A complete list of all river systems connected to its respective price areas (in the SHOP model) is shown in the table. Pålsbu, Nore 1, Nore 2, Sy-Sima and LangSima were initially placed in NO1. After the previous extension of NO5, they are now a part of that price area (according to the SHOP model).

NO1 Oslo	NO2 Kristiansand	NO3 Trondheim	NO4 Tromsø	NO5 Bergen
	Mår	Grytten	Øvre Røssåga	Bjølvo
	Kjela	Mardal	Nedre Røssåga	Målset
	Songa	Monge	Rana	Refsdal
	Vinje	Osbu	Langvatn	Hove
	Tokke	Aura	Bjerka	Leirdøla
	Byrte	Gråsjø	Svartisen	Jostedal
	Lio	Trollheim	Kobbelv	Makkoren
	Hogga	Nord Svorka	Båtsvatn	Eiriksdal
	Saurdal	Svorka	Norddalen	K5A
	Kvilldal	Nea	Skjomen	K5B
	Hylen	Nedalsfoss	Innset	K2
	Øvre Berså	Vessingfoss	Straumsmo	K3
	Nedre Berså	Nea	Bardufoss	Pålsbu
	Mågeli	Fossan	Alta	Nore 1
	Tysso2	Tya	Adamselv	Nore 2
	Oksla	Gresslifoss		Sy-Sima
	Jukla	Nedre Nea		LangSima
	Mauranger	Heggsetfoss		
		Bratsberg		
		Nidelv		
		Løkaunet		
		Svean		
		Fjæremsfoss		
		Leirfossene		
		Øvre Leirfoss		
		Nedre Leirfoss		

APPENDIX IV – OTHER PRICE AREA OPTIMIZATIONS

High price level, high balancing market price deviation, low net imports. NO4, 14th of March

Scenario	Income	Potential improvement	in % of	Sale	Startup costs	Reservoir value
S1	277,438,670	0	0.0000%	22,010,626	26,420	255,454,464
S2	277,432,379	6291	0.0286%	21,927,591	28,050	255,532,838
S3	277,431,877	6793	0.0309%	21,757,772	28,720	255,702,825
S4	277,426,715	11955	0.0543%	21,799,694	27,700	255,654,720
S5	277,425,699	12971	0.0589%	21,781,140	28,710	255,673,269
S6	277,434,114	4556	0.0207%	21,762,905	27,620	255,698,829
S7	277,432,602	6068	0.0276%	21,884,532	27,630	255,575,700
S8	277,433,160	5510	0.0250%	21,743,488	29,550	255,719,222

High price levels, 8th of April in NO4

Scenario	Income	Potential improvement	Sale	ΔSale	Startup costs	Reservoir value	ΔReservoir
S1	250 851 478	0	23 957 673	0	25 690	226 919 495	0
S2	250 636 195	215 283	22 965 838	-991 835	27 000	227 697 357	777 862
S3	250 658 805	192 673	23 059 837	-897 836	26 690	227 625 659	706 164
S4	250 710 225	141 253	23 273 394	-684 279	26 650	227 463 480	543 986
S5	250 709 918	141 560	23 305 105	-652 568	25 610	227 430 423	510 928
S6	250 790 395	61 083	23 594 021	-363 653	25 790	227 222 164	302 669
S7	250 843 775	7 703	23 955 043	-2 630	27 440	226 916 172	-3 322
S8	250 685 593	165 885	23 236 013	-721 660	28 250	227 477 830	558 335

Low price levels, 23rd of June in NO4

Scenario	Income	Potential improvement	in % of	Sale	Startup costs	Reservoir value	ΔReservoir
S1	241,983,673	0	0.0000%	9,551,507	106,990	232,539,156	0
S2	241,974,194	9,479	0.0992%	9,579,065	106,060	232,501,189	-37,966
S3	241,968,720	14,953	0.1566%	9,596,043	104,630	232,477,307	-61,848
S4	241,960,001	23,672	0.2478%	9,631,017	105,480	232,434,465	-104,691
S5	241,947,009	36,664	0.3839%	9,637,233	107,360	232,417,137	-122,019
S6	241,727,106	256,567	2.6861%	9,953,501	113,800	231,887,405	-651,751
S7	241,638,380	345,293	3.6151%	10,050,319	114,890	231,702,951	-836,205
S8	241,800,352	183,321	1.9193%	9,879,996	114,170	232,034,525	-504,630

High price level, high balancing market price deviation, low net imports. NO2, 14th of March

Scenario	Income	Potential improvement	in % of	Sale	Startup costs	Reservoir value	ΔReservoir
S1	369,787,709	0	0.0000%	28,287,556	85,260	341,671,623	0
S2	369,747,915	39,794	0.1407%	28,174,275	89,220	341,662,861	-8,762
S3	369,745,566	42,144	0.1490%	28,134,524	89,220	341,700,262	28,639
S4	369,662,958	124,752	0.4410%	27,334,071	101,240	342,430,126	758,503
S5	369,679,679	108,031	0.3819%	27,364,531	103,080	342,418,228	746,605
S6	369,742,717	44,993	0.1591%	28,271,340	88,420	341,559,797	-111,826
S7	369,719,966	67,744	0.2395%	27,916,575	93,040	341,896,430	224,808
S8	369,749,991	37,719	0.1333%	28,096,587	91,320	341,744,724	73,101

Low price level, NO2 9th of July

Scenario	Income	Potential improvement	in % of	Sale	Startup costs	Reservoir value
S1	397,496,815	0	0.0000%	8,911,535	69,550	388,654,829
S2	397,494,179	2636	0.0296%	8,905,629	70,930	388,659,479
S3	397,490,929	5886	0.0660%	8,920,443	73,460	388,643,946
S4	397,493,168	3647	0.0409%	8,901,638	72,080	388,663,609
S5	397,495,413	1402	0.0157%	8,899,602	70,040	388,665,850
S6	397,488,071	8744	0.0981%	8,937,025	73,870	388,624,916
S7	397,485,247	11568	0.1298%	8,925,095	71,990	388,632,141
S8	397,488,461	8354	0.0937%	8,922,246	71,880	388,638,094