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Hydropower investment decisions

The ProdRisk-Shop simulator: decision support tool for revenue calculations

Stefan Rex, Birger Mo, Linn Emelie Schäffer, Siri Mathisen

HydroCen

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Abstract

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The transition to a renewable based power system induces new opportunities and challenges for hydropower producers. In the Nordic region, reservoir hydropower is expected to play a key role in smoothing out variability in wind power, solar power and load by ramping up and down production in response to the forecasted power prices. Hydropower operations are thereby changing due to the structural changes in the power sector. At the same time, the Nordic hydropower fleet is aging. Consequently, we see a growing focus on maintenance and refurbishment strategies to extend component lifetimes and optimise re-investments. Also, a significant share of the hydropower plants' concessions is planned to be revised. In total, these events provide an excellent opportunity to consider upgrades of Norwegian hydropower plants, such as investments in larger turbines, pumped storage plants and other components, to improve plant performance considering future market needs.

The research in Project 3.3 of HydroCen is mainly conducted by SINTEF and has focused on decision support for upgrading and investment in hydropower. The work has concluded in the development of a new tool for calculation of production revenues for individual hydropower systems. Estimation of revenues are important parts of the net present value calculations used in traditional investment analysis. The project also included one PhD at NTNU which has focused on different aspects of the more general investment problem under uncertainty.

This report shortly summarises the simulation tool developed for revenue calculations in investment analyses, and documents newly developed functionality. Firstly, we have developed a re-optimization framework. Testing of the functionality has demonstrated that repeatedly updating the strategy during the simulation sequence is valuable, especially for systems where head dependencies are of importance. Secondly, the simulator has been expanded to include a capacity market. The results show a significant impact on the reservoir management of considering capacity markets in the strategy calculation. With increasing importance of such markets, this simulator functionality is expected to become more important in future.

Unfortunately, added functionality usually increases the computational time substantially. Both the re-optimization of the strategy and the inclusion of capacity markets gave considerably longer calculation times. To reduce the computational burden of the simulator, a snipping methodology has been developed. This functionality allows for only a smaller part on the hydropower system to be considered in the detailed modelling in the simulator, considerably reducing the calculation burden. It remains to test the snipping functionality with the re-optimization framework and the functionality for capacity markets.

All the functionalities discussed in the report are supported by case studies. Nevertheless, some results indicated that more and slightly different case studies should be considered to fully grasp the value, and limitations, of the new developments. Furthermore, several important aspects in investment analyses are not, or just briefly, considered in this work, such as potential revenues from ancillary markets. More research is therefore needed to better consider the implications of the transition of the power system in the investment process. Still, research conducted in WP 3 of HydroCen constitutes a step in the right direction and an excellent basis for further research on the topic.

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Sammendrag

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Overgangen til et kraftsystem basert på fornybar energi gir nye muligheter og utfordringer for vannkraftprodusenter. I Norden forventes det at magasinkraftverk vil spille en nøkkelrolle i å utjevne variasjoner i vindkraft, solkraft og forbruk ved å justere produksjonen opp og ned i henhold til forventede kraftpriser. Driften av vannkraftverkene endrer seg dermed på grunn av de strukturelle endringene i kraftsektoren. Samtidig eldes den nordiske vannkraftflåten. Følgelig ser vi et økende fokus på vedlikeholds- og oppgraderingsstrategier for å forlenge komponentenes levetid og optimalisere reinvesteringer. I tillegg skal en betydelig andel av vannkraftverkene få revidert sine konsesjoner. Dette gir en utmerket mulighet til å vurdere oppgraderinger av norske vannkraftverk, som investeringer i større turbiner, pumpekraftverk og andre komponenter, for å forbedre anleggenes ytelse med tanke på fremtidige markedsbehov.

Forskningen i Prosjekt 3.3 av HydroCen er utført hovedsakelig av SINTEF og har fokusert på beslutningsstøtte for oppgradering og investering i vannkraft. Arbeidet har resultert i utviklingen av et nytt verktøy for beregning av produksjonsinntekter for individuelle vannkraftsystemer. Estimering av inntekter er viktige deler av nåverdi-beregninger brukt i tradisjonelle investeringsanalyser. Prosjektet inkluderte også en doktorgradsstipendiat ved NTNU som har fokusert på ulike aspekter av det mer generelle investeringsproblemet under usikkerhet.

Denne rapporten oppsummerer kort simuleringsverktøyet utviklet for inntektsberegninger i investeringsanalyser og dokumenterer nyutviklet funksjonalitet. For det første har vi utviklet et rammeverk for reberegning av strategien gjennom simuleringsperioden. Testing av denne funksjonaliteten har vist at det er verdifullt å gjentatte ganger oppdatere strategien under simuleringssekvensen, spesielt for systemer hvor fallhøydeavhengigheter er viktige. For det andre har simulatoren blitt utvidet til å inkludere et kapasitetsmarked. Resultatene viser en betydelig innvirkning på magasindisponeringen ved å inkludere kapasitetsmarkeder i strategi-beregningen. Med økende betydning av slike markeder forventes denne simulatorfunksjonaliteten å bli viktigere i fremtiden.

Dessverre øker ny funksjonalitet vanligvis beregningstiden betydelig. Både re-beregning av strategien og inkluderingen av kapasitetsmarkeder førte til betydelig lengre beregningstider. For å redusere beregningsbyrden for simulatoren, er en klippemetodikk utviklet. Denne funksjonaliteten gjør at kun en mindre del av vannkraftsystemet inngår i den detaljerte modellering i simulatoren, noe som reduserer beregningsbyrden betydelig. Det gjenstår å teste klippefunksjonaliteten sammen med re-optimaliseringsrammen og funksjonaliteten for kapasitetsmarkeder.

Alle funksjonalitetene diskutert i rapporten støttes av casestudier. Likevel indikerte noen resultater at flere og noe annerledes casestudier bør vurderes for fullt ut å forstå verdien og begrensningene av de nye utviklingene. Videre er flere viktige aspekter i investeringsanalysene ikke, eller bare kort, vurdert i dette arbeidet, som inntekter ancillary services. Mer forskning er derfor fortsatt nødvendig for bedre å vurdere den komplette nytten av fleksibel vannkraft i et antatt fremtidige 100 % fornybare kraftsystemet. Likevel utgjør forskningen utført i WP 3 av HydroCen et skritt i riktig retning og et utmerket grunnlag for videre forskning på emnet.

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Content

Foreword

This report summarises the research conducted in HydroCen WP 3.3 Optimal hydro design in the future power system.

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1 Introduction

1.1 Background

The Nordic power system relies on market-based operation of power plants to ensure cost efficient utilisation of available resources. The ongoing changes in the power system with large integration of variable renewables induce higher variability in power prices. Regulated power generation responds to the price signals, providing a cost-efficient smoothing of variable generation and load. In the Nordic region, variability in wind power, solar power and load is mainly handled by reservoir hydropower ramping up and down production in response to the forecasted power prices. Hydropower operations are thereby changing due to the structural changes in the power sector. At the same time, a large share of the Nordic hydropower fleet is aging as many plants were developed in the mid-20th century. The changing market conditions, as well as the aging hydropower fleet, result in a growing focus on maintenance and refurbishment strategies to extend components lifetimes and optimise re-investments. Also, a significant share of the hydropower plants' concessions is up for revision. It is therefore a good time for several power producers to evaluate the profitability of upgrades of plants, such as investments in larger turbines, pumped storage plants and other components, to improve plant performance considering future market needs.

Investments decisions can include both maintenance decisions to refurbish the plant back to its original state and upgrades to take advantage of technology improvements and to improve the performance in response to changing market conditions. Both maintenance and upgrading strategies must consider a large variety of factors and uncertainties, making the underlying problem and decision processes complex. Decision support tools are therefore useful.

1.2 The general investment/refurbishment planning problem

The hydropower investment (and/or refurbishment) problem is multi-dimensional. The investment problem comprises the option to undertake new investments to maintain, upgrade or expand the production facilities, while evaluating options to produce today or store water for future power generation. Several factors must be considered to determine an optimal, long-term schedule for investments to maximize profit. The problem may include the following considerations:

- Expansion of existing capacity
- Upgrade of existing equipment for improved performance or new functionality
- Design of new generation equipment
- Location of new generation equipment
- Timing of investments, upgrades and maintenance
- Cost of operation, including cost elements such as wear and tear, start/stops, operation below best point, etc.

The investment problem is strongly impacted by the future market conditions which are subject to several uncertain factors, such as:

- Inflow (amount and variation)
- Power prices (level and structure)
- Fuel and CO2 prices
- Prices and volumes for provision of ancillary services
- National and cross-border transmission capacity
- Growth in power consumption and variable renewable power generation
- Market structure and regulatory framework (e.g., tax)
- Risk of standstill and unplanned maintenance

- Technological developments (e.g., properties of new equipment)
- Realised functionality of new equipment
- Investment costs (e.g., equipment and labour)
- Interest rates

The problem is further complicated by the fact that several of the uncertain variables are coupled in time and exhibit serial and/or cross-correlations. Especially, power prices and inflows tend to have some serial correlation. Likewise, properties of equipment (such as failure rate) tend to depend on the state in previous time-steps. In practice, only some of these factors can be considered jointly in the investment problem.

The final decision boils down to whether an investment option (e.g., a new turbine design) is profitable. The profitability of an investment is determined by two main components: the cost and revenue sides. The cost side comprises the actual cost of the investment/maintenance (equipment, labour, etc.), the cost of planned downtime and the risk of failure, while the revenue side depends on the future power production and supply of services to the power system. Increased revenues from an investment project may be obtained through increased efficiencies (e.g., head or turbine improvements), increased operational flexibility (e.g., larger installed capacity or broader range of operation) and additional energy (i.e., more water).

1.3 Current industry practice

The current industry practice in Norway is to use hydropower scheduling models that may include operational constraints and costs (e.g. start-up) to conduct an investment analysis for a discrete set of possible investments. The investment analysis is decomposed into two subproblems:

1. Calculation of expected production revenue for a given production system by simulating operation. The time increment is typically from one week to hourly.
2. Calculation of the net present value (NPV) for a given system including all relevant costs.

The hydropower scheduling and the investment process are not integrated together in one optimization model. Instead, a static analysis is conducted using power prices calculated with models such as the EMPS model (Wolfgang et al., 2009). An overview of modelling tools for system operation and simulation can be found in Helseth et al. (2023). The price characteristics depend on a wide range of factors, such as the total power surplus/deficit in the system, the amount of variable renewable power generation, transmission capacity and fuel prices. Traditionally, uncertainty in fuel prices have not been considered in the calculation of future prices. Instead, several scenarios are usually generated as part of the investment analysis to reflect different developments. Such an approach may underestimate the electricity price uncertainty leading to lower investments in flexibility resources in the power system (Mo et al., 2023).

The expected revenues are calculated by simulating operation using a long-term operational model that considers uncertainty in price and inflow, such as ProdRisk (Gjelsvik et al., 2010). There is currently an interest in investment projects that expand the power capacity and/or add pumping functionality to existing hydropower plants. A common feature of such projects is that there is limited increase in the total electricity production, but rather an improvement of the operational flexibility. The revenue potentials from these projects are therefore strongly impacted by the variability in the power price and the hydropower systems' ability to respond to the short-term variations. Consequently, detailed modelling that captures short-term variations and limitations is becoming even more important, also in investment analyses.

1.4 Motivation and scope

This report presents parts of the research conducted in work package 3.3 (WP 3.3) of HydroCen. The objective of the project has been to develop methods and models for calculation of future revenues for hydropower and to support decisions regarding optimal investments in upgrading and expansion projects. The project has not considered the impact of regulatory structures on investment decisions, such as taxes and owner structures, nor hedging and other measures to reduce risk, except what is discussed in the PhD-project summarized below.

The project includes a PhD-project that has investigated different aspects of hydropower investment decisions. The findings have been documented through several articles that form the basis of a doctoral thesis (Kleiven, 2022). The work is also summarized in HydroCen brief nr. 4 (Kleiven, 2023). Firstly, the benefit of coordinated maintenance and replacement planning was shown in Dønnestad et al. (2022). The study demonstrates that a real options perspective on these activities can be valuable. Specifically, the analysis showed the importance of considering several performance-enhancing activities jointly when prices are uncertain. By considering maintenance and replacement jointly, the authors found that maintenance may delay major replacements significantly. Next, the challenge of considering both flexibility in long-term investment decisions and short-term operational flexibility is addressed in Kleiven et al. (2024, working paper). As discussed in Section 1.3, current industry practice is based on static NPV models that do not optimise the timing of investments. Current practice thereby ignores the value of having the flexibility to delay investments into the future. The authors highlight that the timing flexibility of investment decisions previously has been accounted for in the academic literature, but usually at the cost of simplifying short-term operations. This gap is addressed in the study by considering both the value of short-term hydropower flexibility and the implications for long-term capacity instalments in a combined modelling framework. The work considers the performance of operational policies obtained from a heuristic that allows a straightforward integration of seasonal planning and intraweek scheduling. The numerical experiments in the study show that investments may be significantly impacted by including hourly production flexibility, giving up to 20% larger capacity installations. Consequently, the approach of simplifying short-term operation in decision support models for investment decisions may be disadvantageous. Furthermore, it was found that the added value of optimally delaying investments decreased as the hourly price variability increased, compared to a traditional NPV approach. Finally, the PhD project also addressed renewal and capacity investment decisions under limited information about long-term development in market prices (Kleiven, 2022; Kleiven, 2023), as well as the impact of co-dynamics between the level of available resources (i.e., water) and electricity prices in the seasonal production schedule of a hydropower producer operating in hydropower dominated electricity markets (Kleiven et al., 2023).

The remaining part of the research in WP 3.3 has focused on decision support for optimal investments in upgrading and expansion of hydropower plants based on the current industry practice of static scenario analyses and NPV calculations. The profitability of hydropower upgrading- and expansion projects may strongly depend on the changing market conditions and expected higher price volatility in the power markets. To accurately capture the revenue potential of new investments, short-term operational flexibility of hydropower plants should therefore be included in the modelling. The project has built on existing models developed by SINTEF Energy Research, specifically ProdRisk (Gjelsvik et al., 2010) and SHOP (Fosso & Belsnes, 2004; Skjelbred, 2019), to develop a new simulator for revenue calculations for hydropower projects. The simulator is based on the current practise for production planning among Norwegian hydropower producers, linking long- and short-term operational planning. ProdRisk and SHOP are state-of-the-art production planning models used by most of the large Norwegian hydropower producers for decision support. ProdRisk optimise long-term operation of a hydropower cascaded watercourses under uncertainty in inflow and prices, while SHOP allows for a more detailed modelling of the hydropower plants.

This report especially discusses two major developments of the simulator. For totality, we first describe the simulator in Section 2. A more through description of the basic simulator can be found in Mo & Hågenvik (2020). Then, the option to re-optimize the strategy from the long-term model during a simulation is presented in Section 3. The purpose of the re-optimization is to the refine the modelling of head dependent production and to increase the density of cuts closer to the simulated reservoir levels. The motivation for implementing re-optimization and the conclusions from testing with this functionality are discussed in Section 3.1, while the method is presented in Section 3.2. Sections 3.3 and 3.4 present the results from running the simulator with re-optimization for a test system and the Røssåga system, respectively.

Section 4 considers the allocation of reserve capacity for sale in reserve markets. Revenues from sale of system services and capacity may constitute a larger part of hydropower producers' income in the future, as the needs for flexible assets in the power system increase. Including other markets than the regular (day-ahead) energy market in the valuation of investment projects may be vital for the profitability of expansion projects. Functionality for allocation of reserves has therefore been implemented in the simulator. The motivation and main results from the testing of reserve markets in the simulator are presented in Section 4.1. Section 4.2 discusses the impact of including up-regulating spinning and non-spinning reserve markets in the short-term model. The functionality is used for a test system and the RSK system (the hydropower system in Røldal-Suldal), as presented in Sections 4.2.1 and 4.2.2, respectively. Furthermore, the cost of operating below best efficiency point in the short-term model in combination with sales of reserves with spinning condition is assessed for the test system and the eastern part of the RSK system in Section 4.3. Then, in Section 4.4, up- and down-regulating non-spinning reserve markets are included in both the short- and long-term model and run on the test system for the eastern part of the RSK system.

Finally, Section A.1 briefly comments on the simulator prototype, the accessibility of the code for external use as well as available documentation.

2 The ProdRisk-SHOP simulator

The ProdRisk-SHOP simulator is developed as a decision support tool for investment analyses. Investment analyses require a sufficiently long simulation period, while also considering the technical details of the short-term operation. The ProdRisk-SHOP simulator combines the long- and short-term perspectives by coupling the strategy model, ProdRisk, and the operational model, SHOP, in a combined framework. The simulator can thereby be used to calculate revenues for different investments alternatives, imitating the use of long- and short-term optimisation models in real life operational. A prototype version of the simulator was finalized for testing in 2020. The implementation and test cases are described in HydroCen report nr. 15 (Mo & Hågenvik, 2020).

ProdRisk can be used to calculate a strategy for the operation of a hydropower system over a planning horizon of usually 2-5 years. The model uses a stochastic dual dynamic programming (SDDP) based algorithm consisting of backward recursions for strategy generation and forward simulations for strategy testing. A *strategy* is represented by so-called Benders cuts, or linear inequalities, which can be interpreted as water values. A main limitation of the SDDP algorithm is that it requires a convex model formulation, fundamentally restricting the physical properties that can be represented in the model. With the aim of reducing this limitation, ProdRisk runs a final simulation on a slightly improved model, including some of the physically correct non-convex relations (e.g., the PQ curve), once convergence between the forward simulations and backward recursions has been reached. However, there is still a gap between the model of the system used in the final simulation, and a physical correct model of the system. The ProdRisk-SHOP simulator takes this final simulation to another level: Instead of improving the physically descriptions used in the ProdRisk final simulation model, the short-term model SHOP is used to perform the final simulation of the system. SHOP is a short-term, deterministic optimization tool in which most of the physical details are modelled. This way, the simulator can provide reliable economic results that account for physical details.

The simulator is based on two main principles. First, the ProdRisk model calculates a strategy for utilisation of the hydro resources using SDDP. The strategy describes the relation between the expected future value of power production and the state of the system, namely the storage level in the reservoirs, inflow and market price. The strategy is represented in the optimisation model by linear constraints defined for each week in the planning horizon, referred to as cuts. Second, the SHOP model is used to conduct a sequential simulation of the hydro system week by week using the strategy from ProdRisk (i.e. cuts).

The flow chart of the ProdRisk-SHOP simulator is shown in Figure 1, where it is assumed that each scenario corresponds to inflow and price data for a 52-week period. The scenarios are interpreted as consecutive years forming an extended period of operation in the future. First, a ProdRisk series simulation is performed with a long planning horizon of, e.g., three years. The water values at the end of the horizon must be provided as input from another long-term tool, such as Vansimtap. ProdRisk calculates an optimal strategy described by cuts at the end of each week within the planning horizon. Once the initial ProdRisk simulation has terminated, a series of SHOP simulations is invoked. Each SHOP simulation runs over one week and is initialized with the final state of the previous week. Cuts from ProdRisk are used in the simulations to represent the end of week value of storing water in the reservoirs. These weekly SHOP simulations run consecutively through all scenarios, yielding a total of 52 × (Number of scenarios) individual simulations.

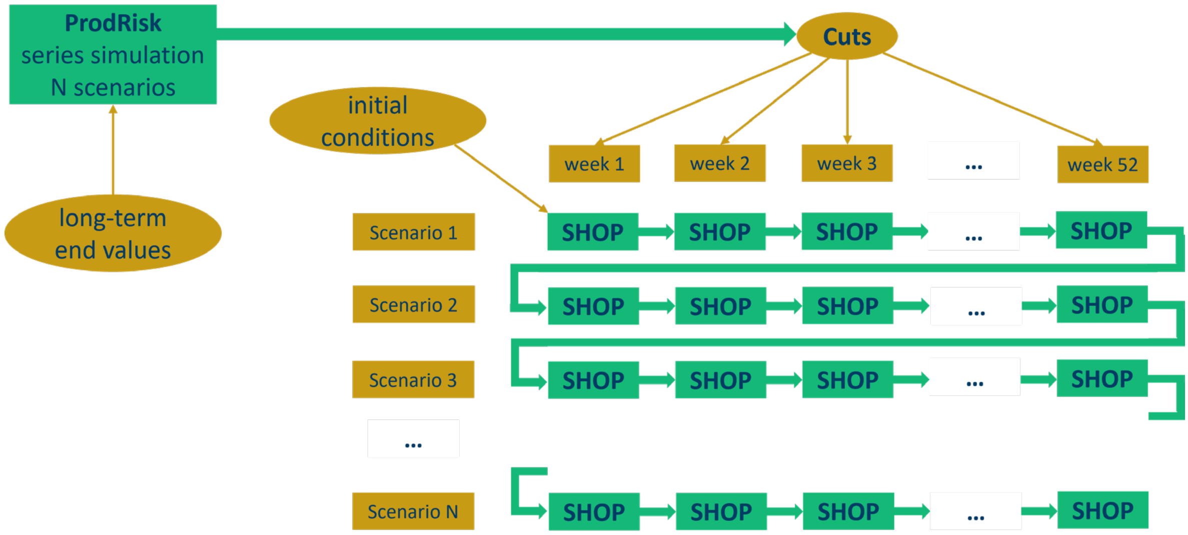

Figure 1. Flow chart of the basic ProdRisk-SHOP simulator.

2.1 Advantages and challenges

For practical use for the Norwegian hydropower system, it is an advantage that the simulator is based on ProdRisk and SHOP as most of the Norwegian hydropower producers use these models in daily operation. The simulator can therefore be used with existing datasets, which lowers the barrier for taking the simulator into use. Still, some harmonisation of the datasets to ensure consistent physical descriptions is to be expected.

Ideally, a detailed physical description of the system should be used in both the strategy calculation and the final simulation, however, this is not achievable due to the complexity and size of the stochastic long-term problem. Instead, the combination of ProdRisk and SHOP allows for a more detailed description of the system to be used in the final simulation. Consequently, the optimal operation of the hydropower system will differ between the short- and long-term model in the simulator. The user thereby obtains more information about the system. Still, this also means that some of the physical details are overlooked in the strategy. Over time, this may lead to a deviation in the reservoir filling between the SHOP simulations and the ProdRisk series simulation. This deviation illustrates the impact of the physical details on the operation of the reservoir, and a large deviation may indicate that the long-term model is overlooking certain important details. However, it is critical that the system descriptions in ProdRisk and SHOP are consistent on physical details that are overlapping among the two models. If not, the results may be challenging to interpret.

A main challenge of the simulator is calculation time, especially for complex systems. The final simulation consists of several successive simulations in SHOP. The solution time is therefore dependent on how efficiently each of the weekly problems can be solved. The weekly short-term problem can be very complex for large hydropower systems, substantially impacting the computational effort. To manage this challenge, a snipping approach can be used to reduce the size of the system modelled in the short-term model, thereby reducing the calculation burden of the simulator without deteriorating the results (Hågenvik et al., 2022).

The remainder of this report discusses two new developments to enhance the performance of the simulator. The first considers certain physical details that can be especially important to the reservoir management (and thereby the strategy), such as the relationship between head and power. The non-linear relationship between head and power cannot be included directly in the formal optimisation problem in ProdRisk but is considered through an alternative approach based on the average assumed head at each point in time (Gjelsvik et al., 2010). During the simulation for some weather years, actual head for a given point in time, may deviate substantially from the initially assumed average head. To mitigate this effect in the simulator, a re-optimisation functionality is presented in Section 3 where the forecast for future head is updated based on the actual head. The second development is that the simulator is developed as a decision support tool for investment decisions. Income from capacity markets is expected to become increasingly important in the future. Therefore, functionality for allocation of capacity for trade in reserve markets has been included in the simulator, as presented in Section 4.

The simulator is mainly developed for use in investment analyses, but as mentioned previously, it is important that the short-term model (SHOP) and the long-term model (ProdRisk) are as consistent as possible for good simulator results. The simulator clearly shows model inconsistencies. Consequently, another application of the simulator is to use it to check and improve the consistency between the SHOP and ProdRisk models used for daily operations. Without a simulator it is more difficult to identify such inconsistencies that are important for optimal utilization of the system.

3 Re-optimization in the simulator

This section describes an extension of the simulator framework where the long-term strategy can be updated during the planning horizon by conducting a re-optimization. The motivation for implementing re-optimization in the simulator and conclusions from the testing are summarised in Section 3.1. The extended simulator framework is described in Section 3.2. Finally, the extended simulator framework has been run on a test system and the Røssåga system, simulation results from the two case studies are presented in Sections 3.3 and 3.4, respectively.

3.1 Motivation and conclusions

An extended simulator framework with re-optimization of the long-term strategy is proposed to overcome some of the drawbacks of the basic simulator framework. The original strategy calculation provides a strategy (i.e. cuts) that can be expected to cover a very broad state space. This implies that there may be a coarse density of cuts in the relevant range of the reservoir fillings seen in the final simulation, resulting in an inaccurate end-value representation. By conducting one or several re-optimizations, a higher density of cuts in the relevant range of reservoir fillings is obtained. Furthermore, the strategy (i.e. cuts) can be updated with respect to the present reservoir storage levels. This will mitigate the deviations between the initial reservoir fillings used for head valuation in the original strategy calculation and the actual filling at given point in time during the simulation, which will give a more accurate representation of the heads in the cuts. This is explained further in Section 3.2. The benefit of updating the strategy is connected to the specific modelling of head dependencies in ProdRisk and might not be equally beneficial for another implementation of the SDDP methodology or another modelling of head in ProdRisk.

In the ProdRisk-SHOP simulator, several scenarios are simulated after each other in a serial manner. ProdRisk assumes average heads for each week for all plants to calculate cuts, because the cuts are shared by all scenarios (Gjelsvik et al., 2010). However, the actual reservoir levels in a specific scenario deviate from the average filling, and for some scenarios the difference can be very large. Without feedback from the final simulations, ProdRisk is unaware of the actual reservoir filling, resulting in an inaccurate representation of heads in the strategy calculation. This does not pose issues for the typical use of ProdRisk, where the cuts calculated for the near future are used in the operational planning and the cuts are calculated with the same initial state in all scenarios (in parallel mode). Consequently, in the early part of the simulation horizon, the different scenarios have not yet deviated too much from each other and average heads are a good guess under uncertainty. In a serial simulation, on the other hand, the actual head for some weather years may deviate considerably from the initial assumptions. Furthermore, the intention of a serial simulation is to find precise accumulated results for the entire simulation period. This can for example be as part of an investment analysis. Hence, high accuracy is equally important for all weeks and weather years. Under this premise, using average heads can be a major drawback. The impact of the heads in ProdRisk is two-fold:

1. The heads at the beginning of each week are used to scale the input conversion relation between production (MW) and discharge (m3/sec) (PQ curve) relative to a nominal head. The scaled PQ curve is used for the entire week.
2. The estimated future value of increased heads is precalculated and included in the objective function for each week.

The first point has an immediate impact on the production, while the second point gives a future "head value" of more water. The consequences of inaccurate heads must be investigated through simulations. The impact depends on the system in total, and in particular on the volume-head relations of each module.

The re-optimization functionality in the simulator invokes repeated new runs of the ProdRisk model based on certain criteria. The purpose is to update the long-term strategy based on the actual reservoir filling seen in the final simulation. The new ProdRisk runs are conducted in parallel mode over a shorter planning horizon, using information from the initial ProdRisk strategy and simulation to calculate updated cuts. The updated cuts are then used in the final simulation to achieve more accurate results. This is described further in Section 3.2.

The extended simulator framework with the possibility of updating cuts by repeated re-optimization of the strategy has been tested for two case studies, as described in Sections 3.3 and 3.4. The first case study shows that the basic principle works and that updated cuts can improve simulated operation and revenue. Higher updating frequencies and longer planning horizons in the re-optimization were found to improve the solution. This is as expected, and ideally, re-optimizations should be conducted for every week with long planning horizons (e.g., 52 weeks). However, this is not feasible since re-optimization increases the calculation time considerably. For instance, weekly updates could easily lead to 50 times longer total run time for the simulator, compared to the standard framework without updated cuts (hours per ProdRisk run vs. minutes per SHOP run). For a real system, this would amount to several days to complete one simulator run. In practice, re-optimisations are therefore conducted less frequently and with considerably shorter planning horizons.

For a realistic case study, the Røssåga system, the situation is less transparent due to model differences between SHOP and ProdRisk, and the less dominant impact of heads. However, when the system contains enough water to avoid empty reservoirs over a longer period, updated cuts seem to improve the profit in the SHOP simulation.

3.2 The re-optimization framework

The re-optimization framework is based on several additional strategy calculations in ProdRisk at given points in time during the final simulation. A new ProdRisk simulation that starts at the correct initial state can be run to calculate cuts with the correct heads for a certain week in the simulation period. However, starting from scratch in each week with a long-term ProdRisk simulation is not feasible regarding computation time. Therefore, we suggest a scheme where cuts are updated with less computational effort by a new layer of shorter ProdRisk simulations. The initial series simulation with a long horizon is run as before and calculates original cuts for a broad space of states based on average reservoir trajectories, see Figure 2(a) where the red line illustrates the average. Despite their inaccuracies for any specific scenario, these cuts are still useful to describe the overall long-term strategy. Instead of passing the original cuts directly to the weekly SHOP simulations for the entire planning horizon, they are used as end-values for a set of additional ProdRisk simulations (updates) that calculate refined cuts based on updated heads at a given point in time. The update runs are set up with the following properties:

- The initial state is set to the actual state of the system according to SHOP, thus enabling feedback from the simulation phase to the calculation of cuts.
- Updates are run in parallel mode in ProdRisk. This is necessary to control the initial state. This also provides a higher density of cuts in the relevant range of reservoir fillings.
- The value of water at the end of the planning horizon is represented by cuts from the initial series simulation in ProdRisk.
- The update horizon is significantly shorter than in the initial simulation (maximum 52 weeks). The end-value cuts at the end of the planning horizon contain sufficient information about the long-term strategy.

Each short ProdRisk simulation produces a new set of updated cuts that is used by the following SHOP weeks, until the next update is invoked. The updated cuts account for the correct heads according to the system state and have a higher density close to the optimal reservoir trajectory in each scenario, as shown in Figure 2(b). Thus, SHOP is provided with precise information even when its strategy starts to deviate from the one found by ProdRisk. Such deviations between the simulated reservoir fillings in ProdRisk and SHOP are expected because of the different level of details in the models. This implies that the original strategy without updates might become inaccurate.

The frequency and horizon of the short ProdRisk simulations are parameters of the simulator that can be adjusted to balance calculation time and accuracy. Longer planning horizon and more frequent updates will always be better but increase the computation time. The update horizon must at least span the interval until the start of the next update, such that updated cuts are available for all weeks. There is flexibility, though, in choosing the overlap of consecutive update simulations, see Figure 2(c). The benefit of such overlap, and whether short intervals or a longer horizon should be prioritized, must be evaluated through testing. The highest frequency of shorter ProdRisk simulations would be once per week, and result in as many ProdRisk simulations as SHOP simulations, and therefore a quite long computation time. The full simulator framework including updated cuts is shown in Figure 3.

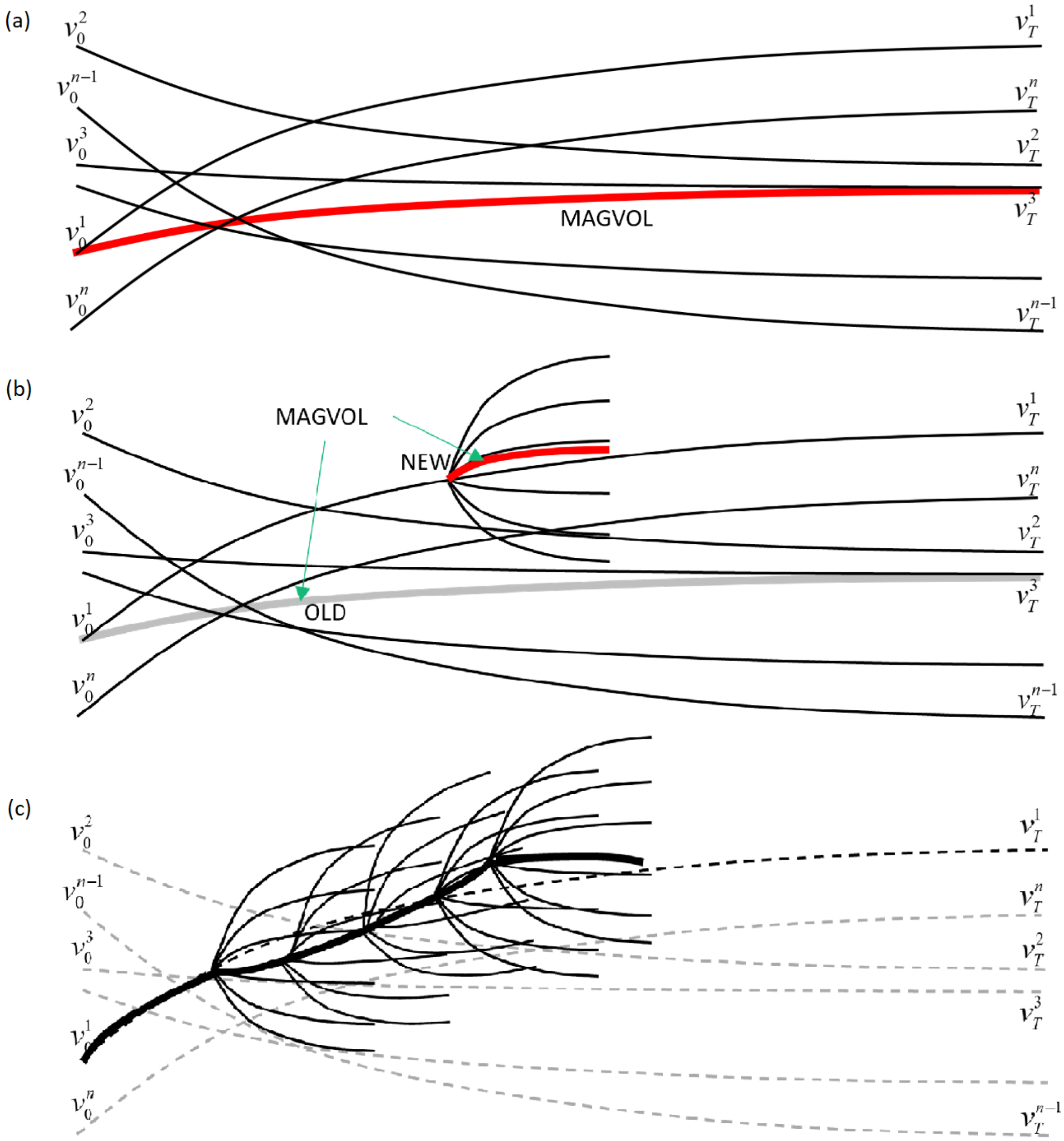

Figure 2. Schematic view of ProdRisk updates. (a) The initial pseudo-series simulation creates rough cuts based on an average reservoir trajectory (to account for heads) with a long horizon. (b) A parallel ProdRisk run with short horizon calculates cuts based on the correct state of the system and with higher density of cuts in the relevant range. (c) Cuts must be updated repeatedly along the simulated strategy. The overlap of simulations depends on the update interval and horizon. The red curve shows the original and updated reference volume for head.

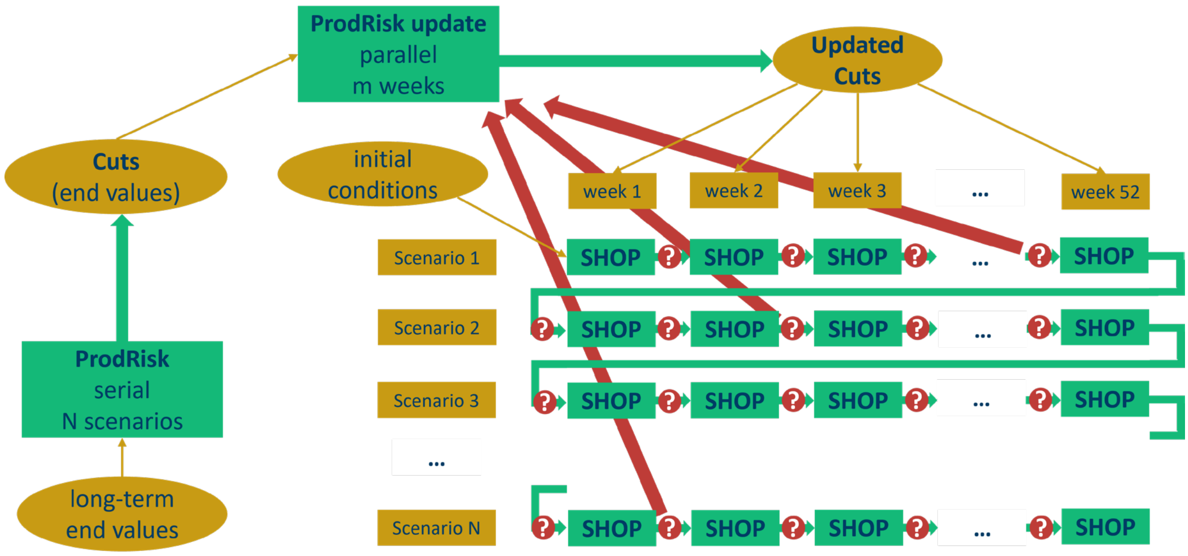

Figure 3. Flow chart of the ProdRisk-SHOP simulator with updated cuts. The strategy is updated at several points in time by running ProdRisk for a shorter planning horizon.

3.2.1 Modes of operation

More generally, one can define an update condition that is not only based on a fixed time interval between updates, but on several checks like the discrepancy between the current state and the average scenario, or the reservoir filling found by SHOP and ProdRisk. This condition is checked prior to each SHOP week and launches a ProdRisk re-optimization for updated cuts if needed. The extended framework in Figure 3 allows for three different simulation modes:

1. ProdRisk-SHOP without updates: If the update condition is defined as always *False*, the simulator is reduced to the basic framework, and SHOP receives cuts from the initial series simulation. This mode is used as a reference to evaluate the benefit of updates.
2. ProdRisk-SHOP with updates: Cuts are updated based on the present state of the SHOP simulation as illustrated in Figure 3. The updated cuts are passed to the following SHOP weeks.
3. ProdRisk simulator with updates (no SHOP simulation): This is the same updating principle as in 2 except that the simpler ProdRisk functionality is used for the final simulation. While this mode loses all physical details from the SHOP model, it is useful to check whether updated cuts give an advantage in ProdRisk itself.

In the following, all results from ProdRisk with updates have been obtained in mode 3, whereas results from SHOP have been obtained in mode 2.

3.3 Technical verification: test case

An artificial, simple test system consisting of two reservoirs, Module A (684 Mm3) and Module B (104 Mm3) is used to test the re-optimization functionality in the simulator. As illustrated in Figure 4, both modules have one power plant with one generator each, and the efficiency of all components is assumed to be 100%.

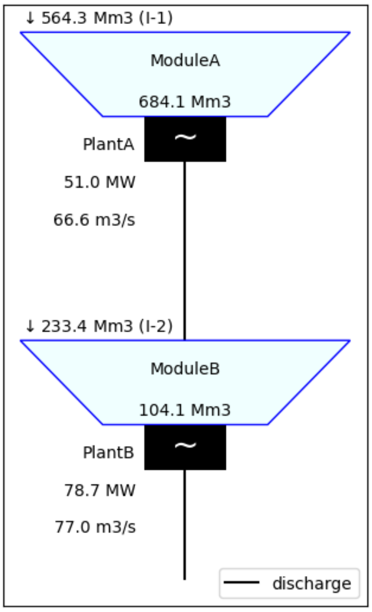

Figure 4. Illustration of the simple test system.

3.3.1 Without variable head

In the first test case, heads are assumed to be independent of the reservoir fillings. Given the very low level of physical detail, the ProdRisk and SHOP models are equal. Hence, close to identical results from ProdRisk and SHOP are expected in this test. Furthermore, for a small system without variable heads, updating the ProdRisk strategy cannot have any sizable effect. Thus, this test system can serve as a sanity check of the simulator. The results also show that the optimal reservoir fillings differ only slightly. The deviations in sales revenue between SHOP and ProdRisk are negligible. These results confirm that the technical design and the dataflow between the models in the simulator work as intended.

3.3.2 Update frequency

To study the impact of repeated re-optimizations using ProdRisk, the test system is modified to involve variable heads. Namely, the upstream module (module A) is assumed to have a volume-head-relation that varies linearly between 78m at the minimal regulation level and 106m at the maximal regulation level. This is a significant head variation, where a clear benefit from updating the cuts according to the current reservoir filling can be expected although the system still lacks complexity. No head variations are assumed for Module B.

First, we compare simulation results for different update frequencies for the repeated ProdRisk runs. The updates are always run with a horizon of 52 weeks. Here we use the following three schemes:

- **never**: The simulator runs without updates, and SHOP receives cuts from the initial ProdRisk series simulation.
- **yearly**: Strategy re-optimizations are initiated at the beginning of each scenario, i.e., every 52 weeks.
- **seasonal**: Strategy re-optimizations are initiated every 13 weeks, i.e. four times every simulated historical year.

The strategies obtained from re-optimization differ systematically from the initial ProdRisk series simulation. Mean reservoir trajectories and percentile ranges calculated by ProdRisk for the three schemes are displayed in Figure 5. The simulations with updated strategies always regulate Module A to a significantly higher reservoir level. This improves the head of Plant A compared to the initial strategy. We see larger improvements in the head when using seasonal re-optimization than yearly re-optimization. In contrast, Module B is regulated to a lower level upon re-optimization. While this has no impact on the head of Plant B, it provides more flexibility for the operation of the upstream module. The SHOP simulations follow closely the reservoir trajectories of the updated strategies for both modules and are not shown separately.

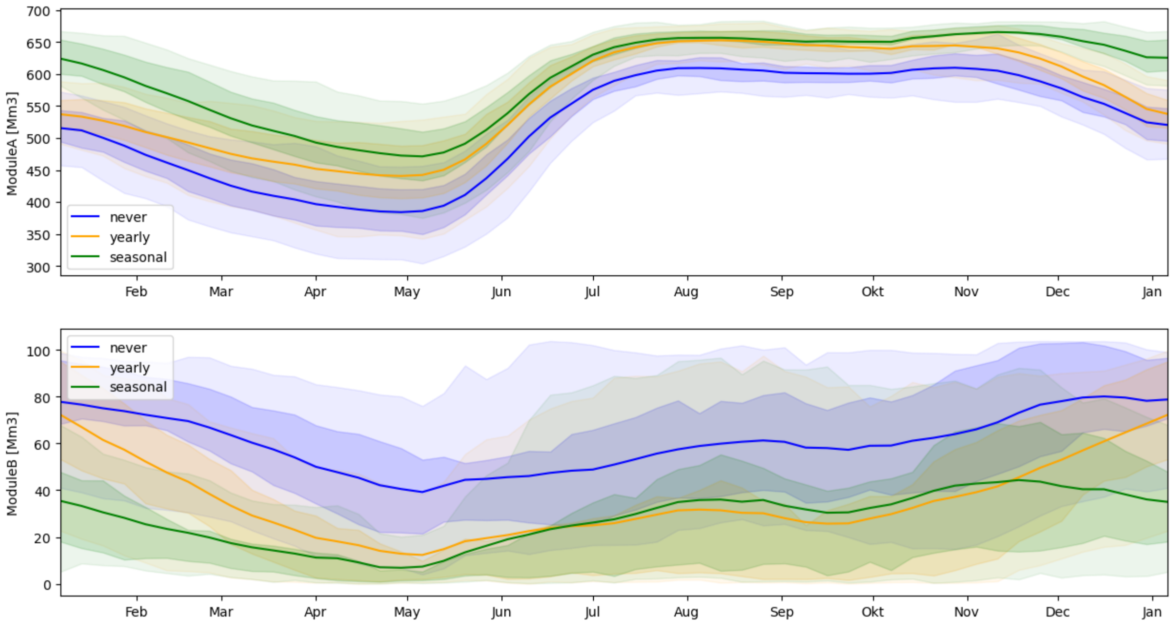

Figure 5. Mean reservoir trajectories calculated by ProdRisk and percentile range for ±20% (dark shade) and ±40% (light shade) for the test case with strategy updates carried out never, yearly or once per season.

The optimization of heads in the update runs meets the theoretical expectation. The update runs mitigate the inaccuracies of using average reservoir fillings in ProdRisk, as previously discussed in Section 3.1, giving improved reservoir management and head optimization. The effect is also clearly visible in the economic results, as shown in Figure 6. Over the course of 50 years, repeated re-optimization of the ProdRisk strategy yields roughly 4 MEUR extra income with yearly updates, and almost 6 MEUR with seasonal updates, compared to the total sales revenue without re-optimization (roughly 870 MEUR). The figure shows accumulated difference in sales revenue as a function of the simulated sequence of weather years. Because the sales revenue numbers do not include the value of storage differences, a simulation period of many years is needed to show the benefit of updating the strategy.

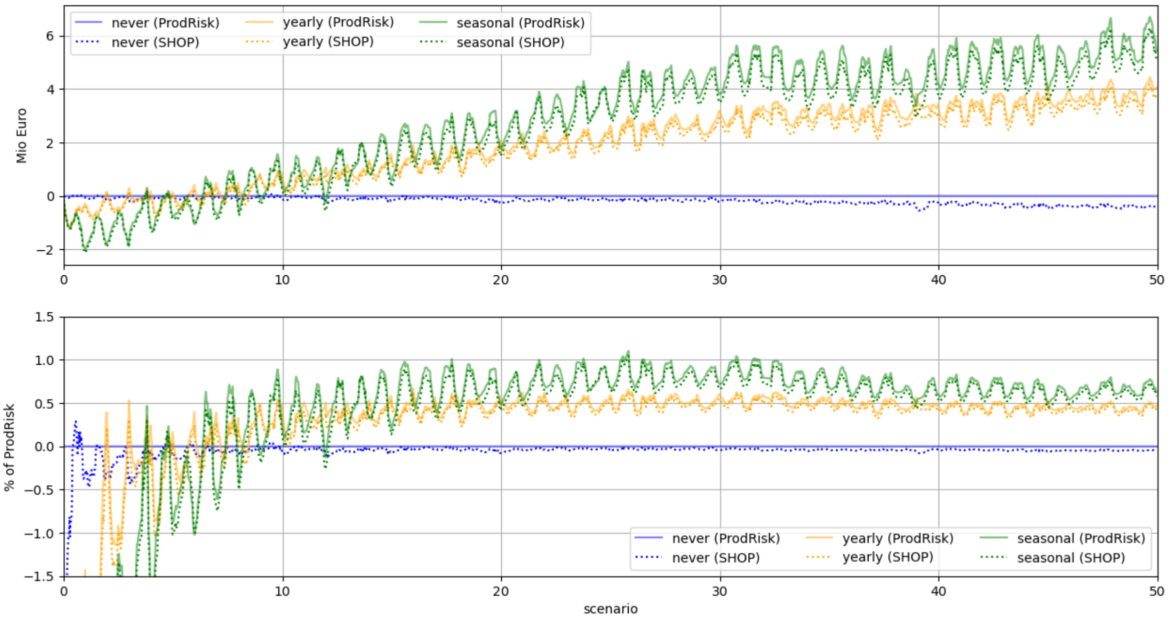

Figure 6. Accumulated sales revenue for optimal strategies calculated by ProdRisk and SHOP with different update intervals in comparison to an ordinary ProdRisk series simulation without strategy updates. Upper panel: absolute difference, lower panel: relative difference. Note that reservoir end values are not included.

3.3.3 Update horizon and overlap

Finally, we test the impacts of the length of the planning horizon of the re-optimizations, and thereby also the overlap between the updates. The test system is run with head variations, like in Section 3.3.2, and a seasonal re-optimization interval (i.e., 13 weeks interval). Planning horizons of 13 weeks (no overlap of update simulations), 20 weeks (7 weeks overlap), and 52 weeks (39 weeks overlap) are tested and compared to simulations without re-optimization.

Unsurprisingly, longer updating horizon gives better economic results as shown in Figure 8. Furthermore, the reservoir trajectories in Figure 7 show that the regulation level of Module A increases with the length of the update horizon. A short update horizon has two disadvantages. First, a short horizon leaves only a short period where the re-optimization can deviate from the initial strategy and improve the results, since the re-optimization uses cuts from the initial series simulation as the end-value setting. Consequently, the updated strategy navigates back towards the original strategy at the end of the update horizon. Second, a short horizon reduces the overlap of the update runs, which causes discontinuities due to the fallback on the initial strategy at the end of the horizon. In the present case, for a 13-week horizon and no overlap, the resulting re-optimized strategy will often release water from Module A to Module B at the end of a season to approach the initial strategy, but abruptly change the ramping direction at the start of the next season to optimize the head again. This causes peaks in the reservoir trajectories, as can be seen in the mean trajectories of Module B in Figure 7. For longer overlap, on the other hand, the last part of each re-optimization is discarded, and such peaks avoided. Hence, a new re-optimization should be initiated well before the horizon of the previous one is reached.

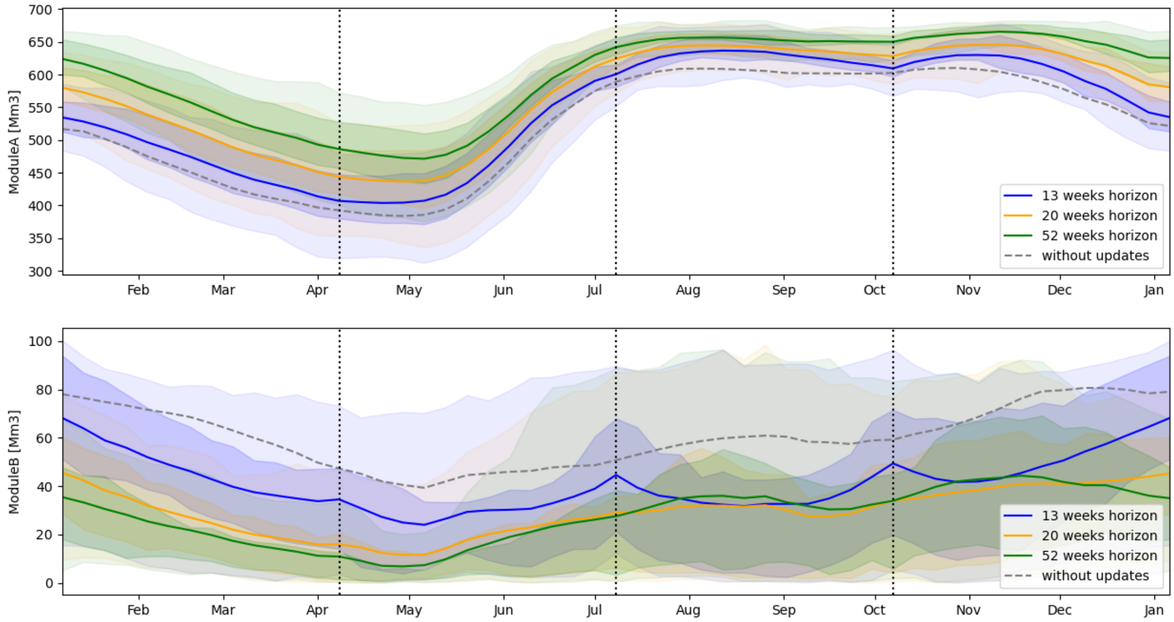

Figure 7. Mean reservoir trajectories calculated by ProdRisk and percentile range for ±20% (dark shade) and ±40% (light shade) for the test case with strategy updates every 13 weeks (indicated by vertical dashed lines) for different horizons of the re-optimization.

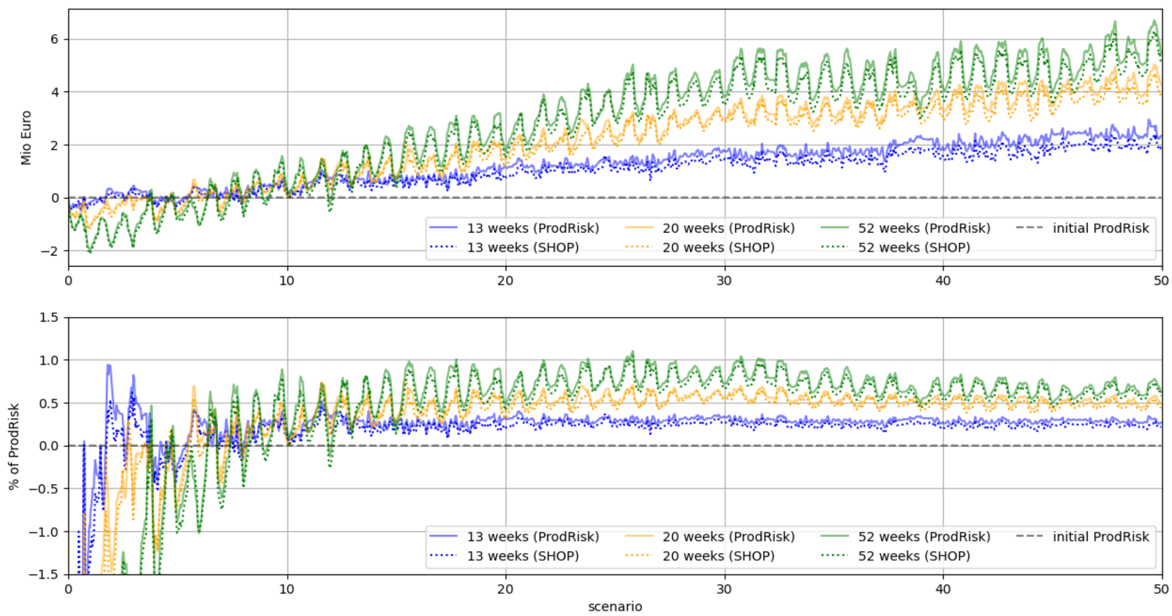

Figure 8. Accumulated sales revenue for optimal strategies calculated by ProdRisk and SHOP with different update horizons in comparison to an ordinary ProdRisk series simulation without strategy updates. Upper panel: absolute difference, lower panel: relative difference. Note that reservoir end values are not included.

3.4 Test case: Røssåga system

To test the simulator on a real hydro system, we use the Røssåga watercourse as a relatively simple example. The Røssåga system, illustrated in Figure 10, consists of four modules, out of which the lowest reservoir is virtual (no reservoir capacity and no production). The upstream module Bleikvatn has no installed plant but release directly into the Røsvatn module. This is by far the largest reservoir, with 2363 Mm3 out of 2600 Mm3 in the entire system. From Røsvatn water is released through the Øvre Røssåga power plant to the Fallfoss module, which has a small reservoir but a large share of the total production capacity in the system (about two thirds). The simulator is run for the Røssåga system for 58 historical inflow and price scenarios (1958-2015).

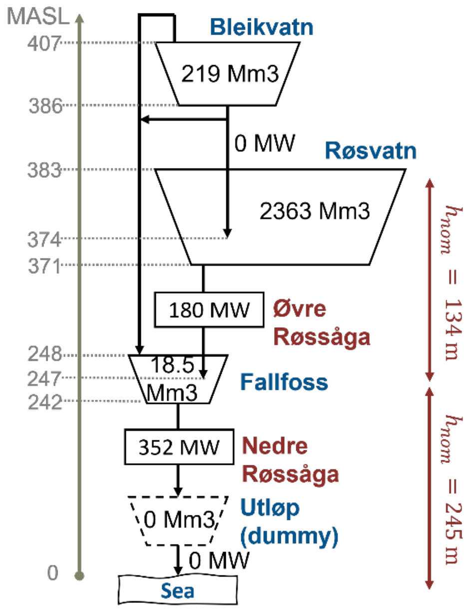

Figure 9. The Røssåga system.

The regulation level at Røsvatn can vary between 370.7 MASL and 383.4 MASL. Including submersion, the head at Øvre Røssåga varies between 136.4m and 122.8m. The difference of 13.6m corresponds to 10% of the nominal head, 133.9m. At Fallfoss, the regulation level lies between 241.9 MASL and 247.9 MASL. The maximal head variation of 6m corresponds to 2.4% of the nominal head, 245m. Thus, head correction is less significant in the Røssåga system than in the modified version of the test case discussed in Section 3.3.

In contrast to the test case, where the physical description was identical in the two models, the model differences between ProdRisk and Shop have important consequences in the Røssåga system. Independent of how the simulator is run, there is a significant discrepancy between ProdRisk and SHOP. Figure 10 shows the reservoir trajectories from the two models without any re-optimization. The simulation results indicate that ProdRisk prioritizes to maintain a stable head for the largest plant, whereas SHOP stores more water upstream. The total sales revenue over all simulation years is approximately 6740 MEUR in ProdRisk, compared to 6280 MEUR in SHOP (7% difference).

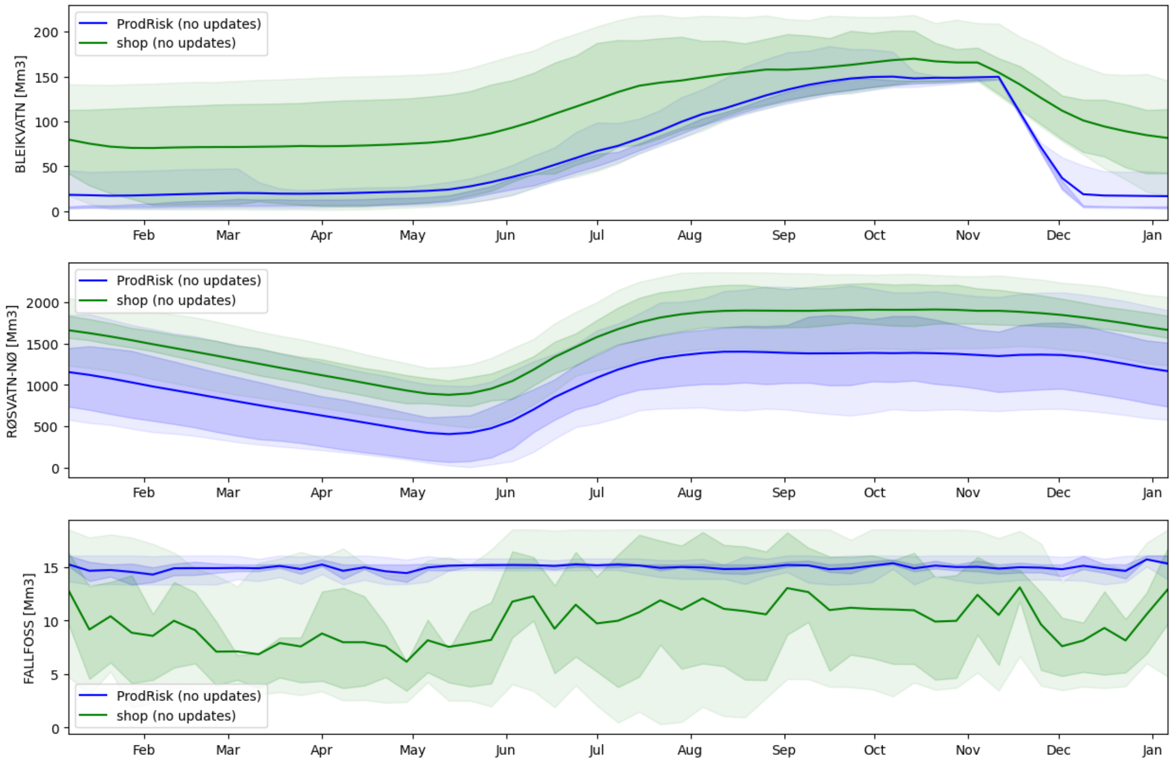

Figure 10. Reservoir fillings for ProdRisk and SHOP strategies without updates. The solid lines are the mean trajectory, while the shaded regions indicate the ±20% (dark shade) and ±40% (light shade) percentile ranges.

The differences between the ProdRisk and SHOP results are partly expected due to differences in the physical details in the models. In the SHOP model, the plants Øvre Røssåga and Nedre Røssåga have 3 and 6 generators, respectively. Each generator is modelled with a detailed turbine and generator efficiency curves and a start-up cost. Furthermore, the SHOP description includes several individual loss descriptions, such as main, penstock and tailrace losses. Nedre Røssåga has a tailrace loss of up to 5.3m alone, which is close to the maximal head variation. Such details are not fully captured by the plant description used in ProdRisk, which explains the different results to some extent. Nevertheless, the relatively big discrepancy may also indicate that the consistency of the models could be improved.

3.4.1 Impact of updated cuts

The simulator is run without updated cuts, with seasonally updated cuts (20 weeks horizon, 7 weeks overlap) and with yearly updated cuts (52 weeks horizon, no overlap). The ProdRisk strategies from the simulations with and without updates are essentially identical, implying that there is no benefit from improved head optimization in ProdRisk for this case. Both economically and in reservoir filling, the difference is within the expected uncertainty. In contrast, when results from SHOP are compared with and without updated cuts, there seems to be a systematic benefit of the re-optimization starting in the second half of the simulation period, whereas no significant differences occur in the first half, as shown in Figure 11.

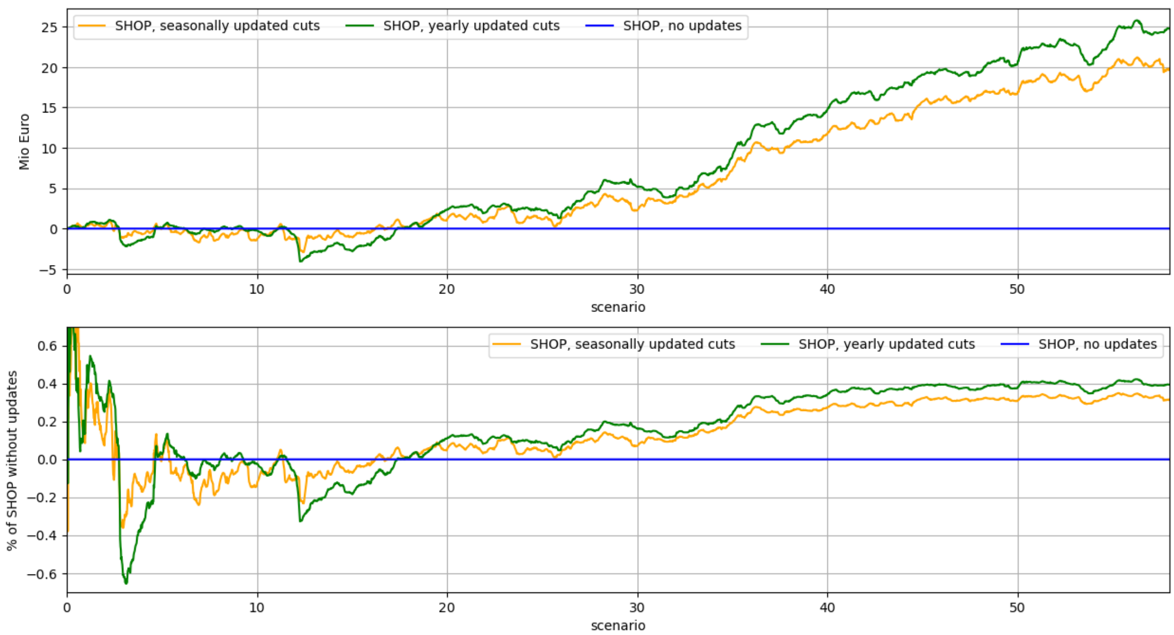

Figure 11. Accumulated sales revenue for SHOP seasonally or yearly updated cuts compared to SHOP without updates.

This unexpected outcome could possibly be explained with the amount of water in the system. Figure 12 shows the minimal filling of the entire system. In most years in the first half of the simulation period, there is a week where the entire system is almost completely emptied by ProdRisk (with or without updates). Without water, the system is necessarily in the same state regardless of the operation strategy. If such a "reset" occurs every year, ProdRisk has not enough flexibility to build up an advantage during the re-optimization (unless, perhaps, with a very long update horizon). In the second half of the simulation period, more water is available. ProdRisk operates with higher minimal storage levels, such that strategy improvements during the update runs are possible. This is when SHOP starts to draw profit from updated cuts. Yearly updates yield more profit than seasonal updates, as seen in Figure 11, indicating that a long horizon is more beneficial in this specific case than a higher update frequency with shorter horizons. This implies that the optimal specifications for update runs is likely to differ from case to case.

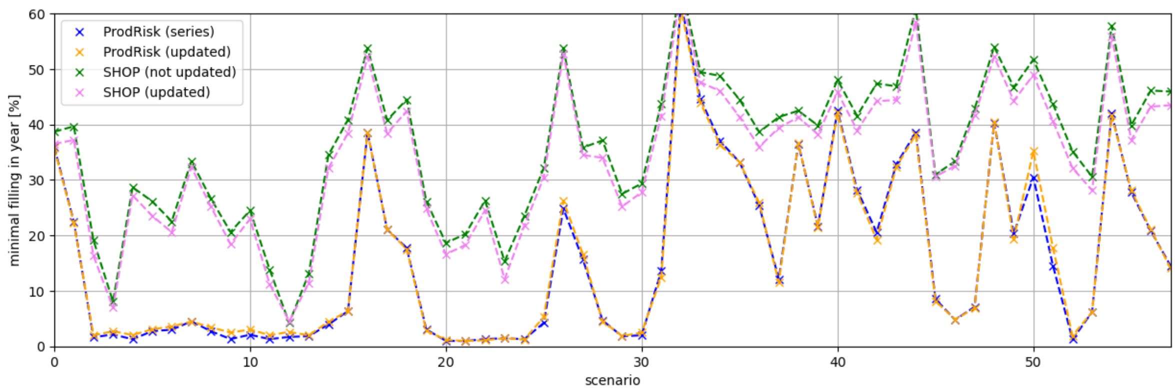

Figure 12. Minimal filling of the entire system in each scenario. In the first half of the simulation period, the large reservoirs are usually almost emptied by ProdRisk at some point during the year.

4 Reserves in the simulator

This section describes an extension of the simulator framework to include a reserve market. In its basic form, the simulator accounts only for the spot energy market. The motivation for considering reserve markets in the simulator and conclusions from the testing are summarised in Section 4.1. The simulator was first tested with reserves in SHOP only, as presented in Section 4.2. Furthermore, Section 4.3 describes the implications of considering the costs of running below best point in combination with up-regulating reserves. Then, finally, modelling of reserve requirements in both the strategy part (ProdRisk) and simulation (SHOP) are discussed in Section 4.4. Relevant case studies are presented in each section.

4.1 Motivation and conclusions

In the future power system, the increasing share of wind and solar generation is expected to cause more volatility and the importance of reserve markets is likely to increase. To be able to analyse the impact of reserve allocation on an investment case, it is important to include reserve markets in the simulator.

The simulator was first tested with reserves in SHOP only, including markets for up-regulation with and without spinning conditions. In this part, reserves were only included in the short-term model, assuming that the strategy calculated by ProdRisk remains valid. One objective of the work was to assert this assumption. Furthermore, the long-term impacts on production and revenue of trading in reserve markets were studied, considering both reserves with and without spinning condition. When up-regulation reserves are considered in the optimization, an economic incentive to run generators below optimal efficiency can occur in some price periods. Functionality to estimate the costs of wear for generators when running below optimal efficiency has been developed as a part of HydroCen (Eggen, 2022; Eggen & Belsnes 2023) and is implemented in SHOP. The additional costs of wear for generators when running below the optimal efficiency point, when considering up-regulating reserves, are addressed in Section 4.3.

A test system and the Røldal-Suldal hydropower system (RSK) was simulated with up-regulation reserves in the short-term model. Simulations of the test system is described Section 4.2.1 and demonstrates that the functionality works as intended in the simulator framework. The RSK case study described in Section 4.2.2., shows that reserve markets may have a significant impact on both the total revenue and reservoir operation. Thus, the assumption of approximately unchanged strategy (i.e., cuts) does not hold for this case when considering up-regulation reserves. This is a notable finding given that water values that do not account for reserve markets are presently used by many hydro producers in the Nordics. This finding is in line with, although shows it more clearly, than an earlier research project on integrating balancing markets in ProdRisk (Helseth et al 2016). The new results are based on higher reserve prices than used in Helseth et al. (2016). In general, energy prices seem to become more volatile and the demand for reserves is expected to increase. The case study was based on the rather extreme price year 2022. Therefore, the assumption might still hold for cases where reserve markets have less impact relative to the spot market in terms of market volume, price ratio and participating plants. Also, the assumption may hold if both up- and down-regulation reserves are included with approximate symmetry, which should be tested further. Finally, the discharge cost curve functionality in SHOP has been evaluated together with spinning reserves. The cost curve was found to change the usage of generators and the allocation of reserves considerably. In addition, the estimated cost of wear was found to be reduced by approximately 50%. In contrast, it was difficult to identify any changes on operation when it is applied in the absence of reserve markets.

The assumption that the strategy calculated by ProdRisk remains valid when including up-regulating reserves in the short-term model was found to be invalid for the RSK case. The simulator has therefore been tested with reserves in both the long- and short-term model in Section 4.4. Up- and down-regulating reserves without spinning requirements have been included in the short- and long-term model in the simulator for the East RSK case. The results are compared to simulation results where reserves are only considered in the short-term model. The results show that the reservoir management changes considerably when reserves are considered in both models, compared to only in the short-term model. Including up-regulation reserves in both models reduces how much the average filling increases and vice versa for down-regulation reserves. Still, the average reservoir filling is lowered when both up-and down-regulation reserves are included, indicating that the sensitivity to the regulation direction differs. In general, the reservoir management becomes more similar to the case without reserves when reserves are considered in both the long- and short-term model. The results from the case study are discussed further in Section 4.4.1. The differences in the reservoir management are a consequence of changes in the water values, as discussed in Section 4.4.2. The analysis demonstrates that up-regulating reserves reduce the water values by an amount depending on the market capacity. An opposite effect was seen for down-regulating reserves, giving higher water values.

In each case, one should consider carefully which markets and conditions are needed in the simulation, as reserve markets can cause much longer computation times. This is particularly relevant when running the simulator, which comprises a high number of individual SHOP simulations. Details on calculation times are included for some of the case studies in Sections 4.2.3 and 4.4.3.

4.2 Spinning and non-spinning reserves in SHOP

In total, seven reserve market types are available in SHOP to model reserves with different activation requirements. For simplicity, we only use two of them in this work, one without spinning condition (RR) and one with spinning condition (FRR). Furthermore, only up-regulation is considered in this section. Details on the reserve types can be found in the SHOP documentation (SINTEF Energy, n.d.).

The amount of reserve capacity that can be delivered from a spinning generating unit is limited by the maximum and minimum production, in addition to the optimized production level. In SHOP, the maximum and minimum production level consider head-dependencies. Furthermore, active production constraints on the unit are also considered in the reserve capacity constraints. An important aspect regarding the optimization is that spinning conditions require binary variables and the use of mixed-integer programming (MIP), which increases the computation time. Activation of reserves is not included in SHOP.

Make clear if water values are computed with respect to reserve prices in cases below.

4.2.1 Technical verification: test case

The integration of reserves into the simulator framework required some technical adjustments. To verify that the reserve allocation works as expected, a simple test case was conducted. This is an artificial two-reservoir system without head dependence (flat reservoirs) and constant efficiency, as previously described in Section 3.3.

The test case included a non-spinning reserve market ("RR"). Only plant A participated in the allocation of reserves. The reserve market was assumed to be unlimited, allowing this plant to freely distribute its capacity based on profitability. The reserve price was set to the spot price times a scaling factor, with a total of 50 price scenarios (years). This test was repeated for several scaling factors in the range from 0 to 2. The fixed ratio of reserve to spot prices makes it easier to evaluate the obtained results.

Figure 14 shows the mean production and reserve allocation pattern with weekly resolution for different scaling factors, including a reference case without reserves. The production decreases from the reference production to zero as the reserve price is scaled up, while the reserve allocation increases simultaneously from zero to the total capacity of plant A. The results look meaningful in all price regimes:

- ➢ <u>For very low reserve prices</u>, reserve allocation is unfavourable compared to production for the spot market. A numerical artifact occurs for zero prices, where reserve allocation does not affect the objective function, causing arbitrary reserve "sales" as long as production remains the same. A significant reserve volume is allocated even with extremely low prices (factor 0.01), but still without changing the production pattern. In such cases, the entire surplus power which is not used for production gives a small extra income when sold as reserve. This would likely be different with nonzero activation rate.
- ➢ <u>For an intermediate price range</u> (around half the spot price), the production pattern is altered significantly to maximize sales in both markets. During most of the year, a large share of the capacity is allocated for reserves. Only during the spring flood period is the power production for the spot market maximized and the allocation of capacity for reserves reduced.
- ➢ <u>For high reserve prices</u>, it becomes more profitable to spill or bypass water than to produce, such that reserve sales are maximized at each time step. The price threshold for this type of behaviour will depend on spillage penalty values. However, this was not investigated in more detail.

The more plant A is used to allocate reserves, the less water is discharged for production. This leads to a higher water level in the upstream reservoir, while less water is stored in the downstream reservoir. For the highest reserve prices, the downstream reservoir is almost empty throughout the year.

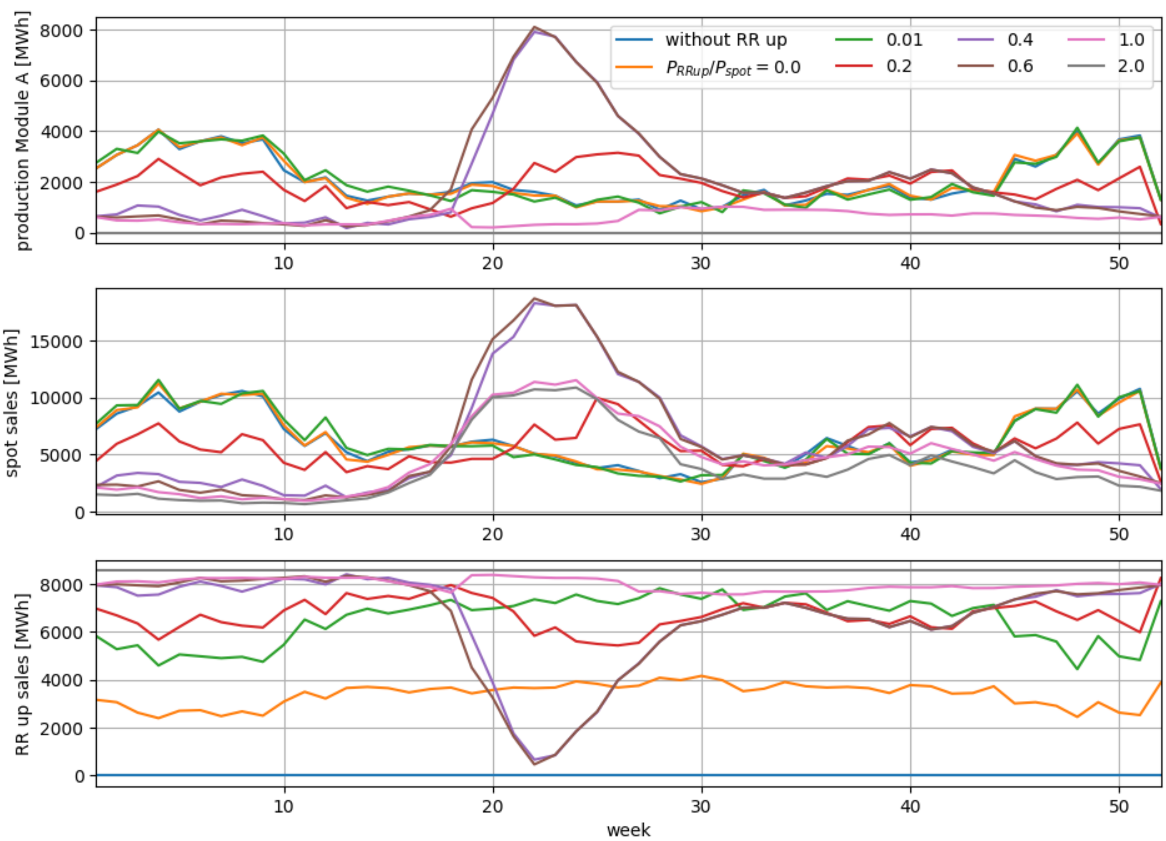

Figure 13. Mean production and reserve allocation for base case with a fixed ratio (see legend) of reserve to spot prices. Panels: production in the module connected to the reserve market (top), total production (middle), and reserve allocation (bottom).

4.2.2 Test case: Røldal-Suldal hydro system (RSK)

Case description

The Røldal-Suldal hydropower (RSK) system is a complex watercourse that is used as a real-world test case. The case is based on system descriptions from the industry, but the model descriptions in ProdRisk and SHOP had to be harmonized for consistent use in the simulator. The topology of the ProdRisk model is shown in Figure 14. The SHOP model is more detailed and contains, e.g., creek intakes and hydraulic reservoir couplings that cannot be represented in ProdRisk.

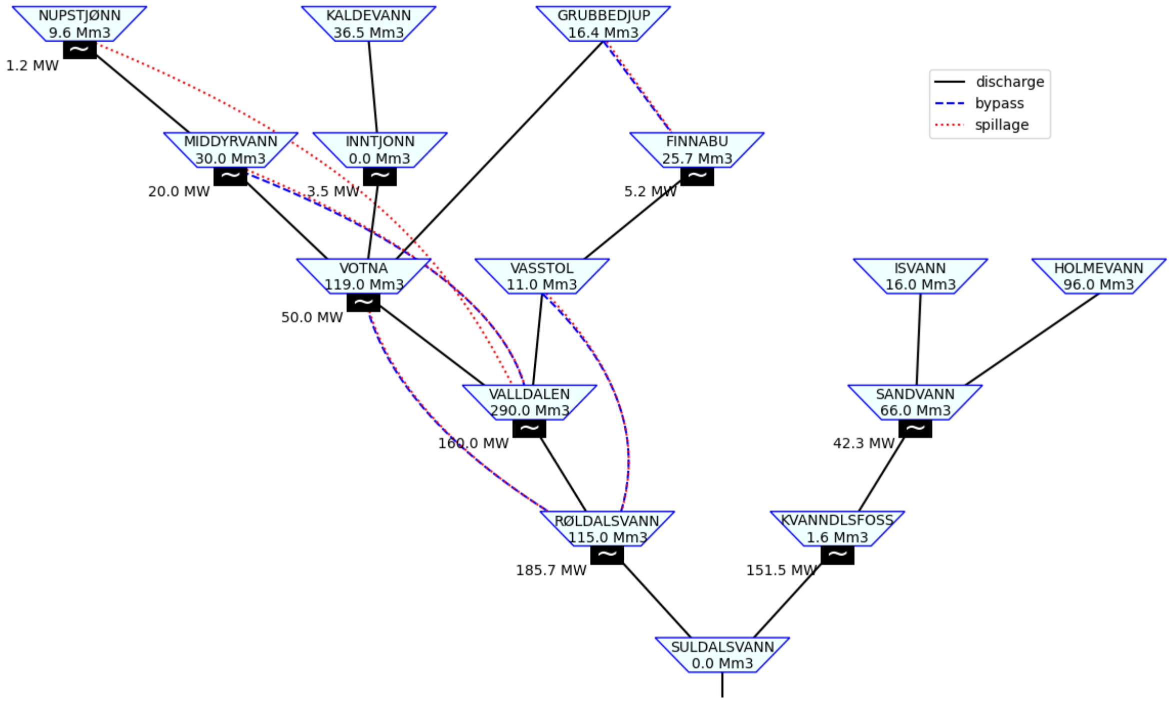

Figure 14. Topology of the RSK system as modeled in ProdRisk.

The RSK system was simulated considering:

1. Only with the spot market, no reserves
2. With non-spinning up regulation reserves ("RR") in SHOP
3. With both spinning ("FRR") and non-spinning ("RR") up regulation reserves in SHOP

It was assumed that all plants participate in all markets. The available market volume was set to 20% of the installed capacity for non-spinning reserves and 10% for spinning reserves. The simulations were run over a period of 20 inflow and price years, i.e., with 20 scenarios in the ProdRisk series simulation and 20 years of week-by-week simulations in SHOP. Longer simulations were not attempted because of excessive calculation times on the small test computer.

For the inflow, historical data was used. The spot price was based on a simulation with the EMPS power market simulator, using the "Low Emission" scenario which resulted from an earlier HydroCen activity (Schäffer & Graabak, 2019). This price series contains 30 weather years with a three-hourly time resolution. The simulator was run with the first 20 of these price years. For the reserve markets, observed prices for one year were taken from the open databases at Nordpool (Nord Pool, n.d.) and ENTSO-E (ENTSO-E, n.d.), and the same prices were repeated each year in the simulator. The reserve prices correspond to NO2 in 2022, therefore the HydroCen series for the spot price was rescaled to the spot yearly mean value of NO2 in 2022. The reserve prices were converted to three-hourly resolution to match the spot price resolution. This was done by taking the average price in each three-hour period. All price series are shown in Figure 15.

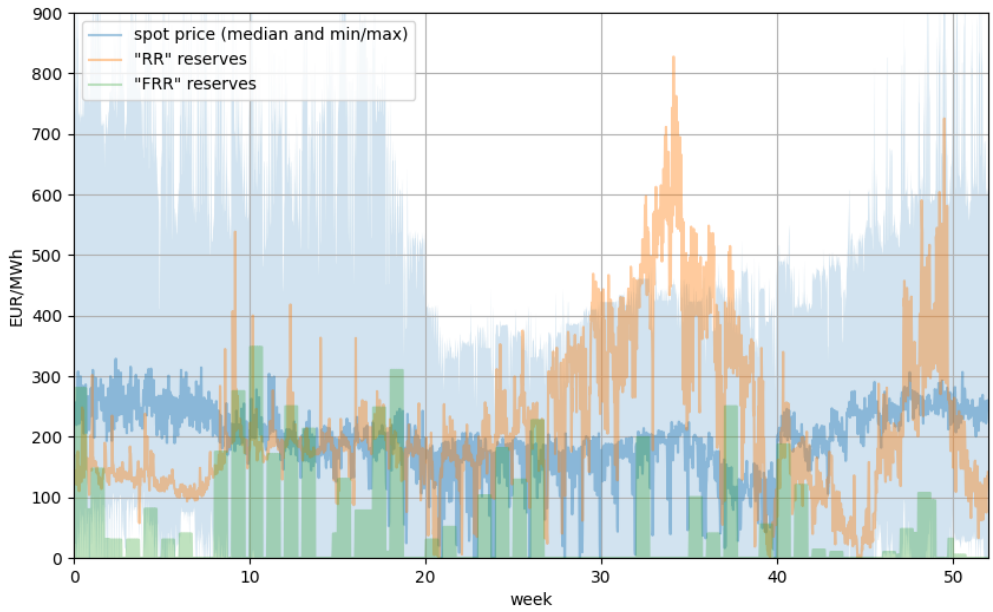

Figure 15. The price series used for the spot market and the reserve markets "RR" (no spinning condition) and "FRR" (spinning condition) in SHOP. (Does axis cover EUR/MWh and EUR/MW?)

Results

The energy and reserve capacities sold in the different markets are compared for all three simulations in Figure 16. On average, production decreases when reserve markets are present. In periods where reserve prices exceed spot prices one can also observe a decrease in maximum production, such as in the late summer. Recall that only up-regulation is included in this test case. Thus, reserve sales give an incentive to leave some production capacity unused. Contrarily, down-regulation would give an incentive towards higher production.

For non-spinning reserves, the average sales are relatively high throughout the year. Thus, even when prices are lower than the spot price, it is often profitable to allocate reserves and thereby generate extra income. This corresponds well to the results from the test case with low reserve prices, as discussed in Section 4.2.1. Again, it is possible that the optimization algorithm would favour less reserve sales if activation rates were included. When spinning reserves are included, these are utilized frequently as well. Due to numerical ambiguity, reserves are even allocated in periods where the price is zero.

Figure 16. The energy sold on the spot market (top), non-spinning reserve market (middle), and spinning reserve market (bottom). Each panel shows the averages as solid lines and the minimum to maximum range as a semi-transparent area. All results are from SHOP.

The spinning condition can in principle cause higher production when reserve prices are high enough to ensure that units are spinning even when the spot price is too low to produce. The spinning reserve price used here is mostly below the spot price, such that this effect is irrelevant for the averaged results. However, it becomes clearly visible in specific weeks. Figure 17 shows the production and allocation of reserves for week 11 in price year 10, for which the spot price is very low (almost zero), and the reserve price is high (maximum). The plot show that minimum production is sustained to enable sales of spinning reserves. Without a reserve market, on the other hand, production drops to zero during most of the week.

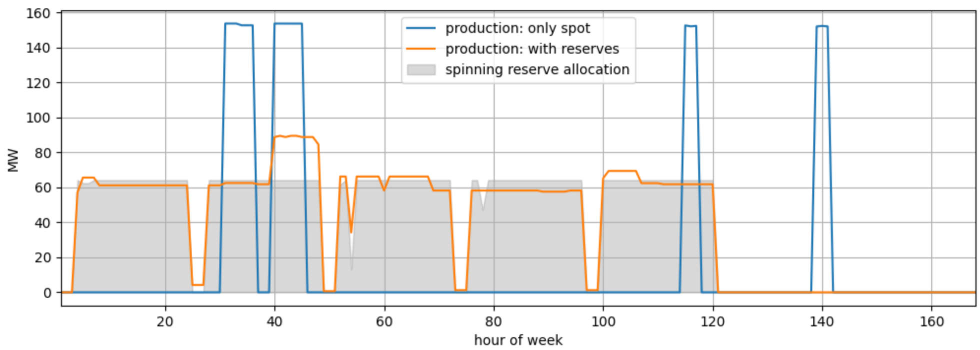

Figure 17. Production and spinning reserves for one specific week where spot prices are very low while spinning reserve prices are high.

The average total filling of the system increases slightly when reserve markets are considered. To find systematic changes in the reservoir management, we divide the RSK system into upstream and downstream reservoirs. In the western watercourse, all reservoirs from Valldalen and below are counted as downstream reservoirs, while in the eastern watercourse, the reservoirs from Sandvann and below are counted as downstream reservoirs. All other reservoirs are counted as upstream reservoirs. The plots in Figure 18 shows that the change in reservoir filling mostly is located in the upstream reservoirs, while the downstream reservoirs show nearly no change. Recall that the reserve markets only are modelled in the short-term model, which receives the same water values in all simulations. Without reserves, the reservoir filling curves correspond well with the long-term model. Hower, with up-regulation reserves a significant deviation between ProdRisk and SHOP appears in the simulated reservoir operation. This deviation indicates that the water values should be calculated including information about reserve capacity markets, more on this in Section 4.4. It should also be noted that the present simulations only included up-regulation. The gap between the simulated reservoir filling curves from the long-term model are smaller if symmetric up- and down-regulation is assumed, which is also discussed in Section 4.4.

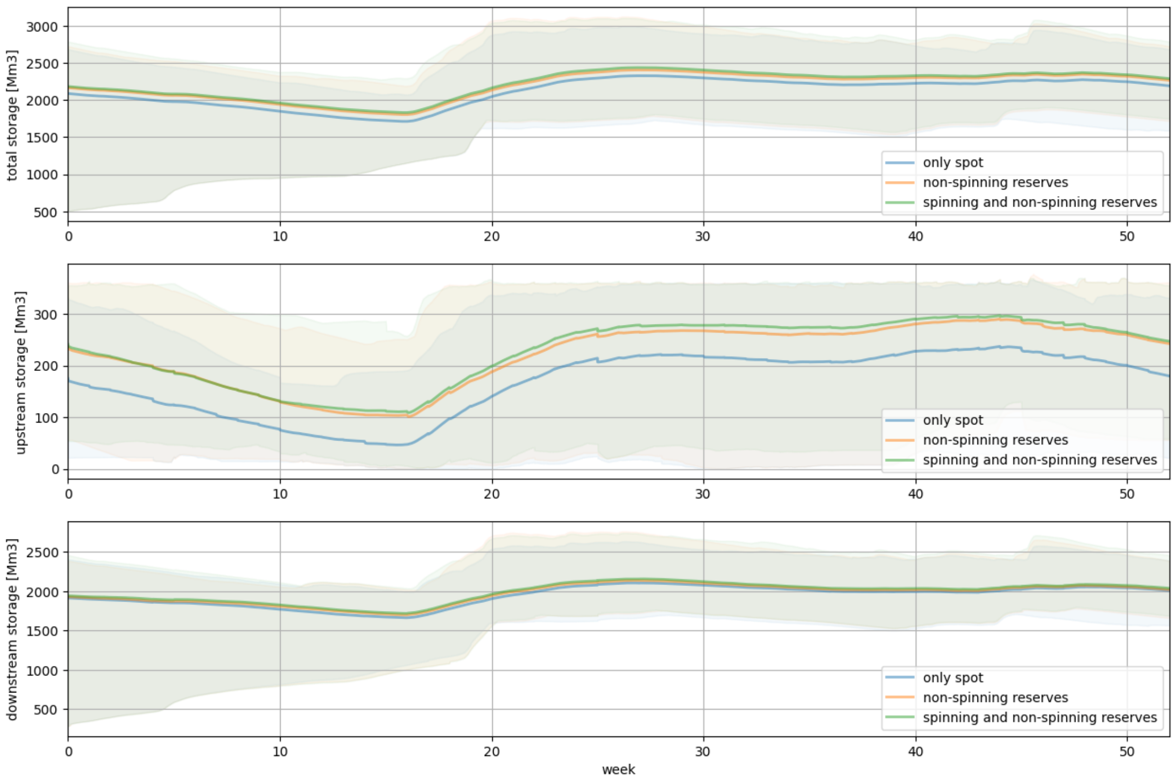

Figure 18. Filling of the total system (top), the upstream reservoirs (middle), and the downstream reservoirs (bottom); lines show the mean value and shaded areas the minimum/maximum range.

The accumulated results from all SHOP weeks in the simulator are summarized in Table 1. The total revenue from all markets increases by roughly 15% when both spinning and non-spinning reserves are included. At the same time, the total production decreases by roughly 9% mainly because more water is spilled, bypassed or discharged at lower efficiency. Given the assumption that 30% of the total capacity in the system could be allocated for reserve sales at any time (the assumed available volume of the reserve markets), these numbers might be larger than the real-life expectation. Simultaneously, the market prices favoured a high use of the available reserve capacity. The seemingly small impact of reserves with spinning condition, on the other hand, can be attributed to the fact that this condition rarely gave changes in the production pattern for the used scenarios. Overall, the simulator gives reasonable results for the long-term impact of different types of reserves in the RSK system under the given assumptions.

Table 1: Accumulated results for RSK with reserve markets relative to the case without reserves.

	Non-spinning reserves	*Spinning and non-spinning reserves*
Production	91.5%	90.9%
Spot revenue	89.5%	88.2%
Spillage + bypass	113.4%	113.8%
Total revenue	114.3%	115.1%
Upstream end value	126.6%	128.2%
Downstream end value	111.6%	117.1%

4.2.3 Calculation time

Depending on the original case, reserve markets can increase the complexity of each weekly problem significantly and thereby increase the computation time. Additional markets increase the number of variables and constraints in the optimization, but a spinning condition also requires a binary variable for unit commitment. Therefore, reserves with spinning condition resulted in a large increase in the simulation time for the test case. However, if mixed-integer programming is used in the model to represent other system properties (e.g., start cost), the relative impact of including reserves with spinning condition is smaller. This was the case for the RSK system. Specifically, the final simulation (i.e., the short-term SHOP simulations) for the test case over 50 scenarios on a PC with 8 cores took:

- 45 minutes without reserve markets
- 1:40h when the non-spinning reserve market ("RR_up") was included
- 6:50h with both non-spinning and spinning ("FRR_up") reserves

For the full RSK system (that already includes binary variables), the computation time of SHOP increases by approximately 25% per additional market. The run time of ProdRisk was unchanged because reserves were only present in SHOP. The discharge cost curve does also require mixed-integer programming. However, because it was used together with start cost and reserves with spinning condition that already have this requirement, there was no major impact on the computation time.

4.3 Operation below best-efficiency discharge: cost of wear

Several relevant technical features are normally not considered in the long-term operational models for hydropower, such as operational failure probability as a function of start-ups, efficiency degradation as a function of operation and impact of system operation on failure probabilities and component efficiencies. Some of these features can be represented as costs in the short-term operational models if the required data is available. Reserves for up-regulation which require spinning generators can yield an incentive to run units below their optimal efficiency point. Formally, this might be the correct economic optimum. However, one also wants to avoid high wear by driving generators out of their intended range of operation. This was tested in the simulator together with spinning reserves for two cases: the test case and the East RSK case. The results are discussed in Sections 4.3.2 and 4.3.3, respectively. Non-spinning reserves were not included for simplicity. The case studies are based on the same spot and reserve market prices as in Section 4.2. The assumed discharge cost curve is discussed further below.

4.3.1 Discharge cost curve in SHOP

The increase in the cost of wear that appears when generators are run below their best efficiency point are discussed in earlier HydroCen project (Eggen, 2021). This cost corresponds to the expected lifetime reduction of the unit from one hour operation at the given discharge below best efficiency point. The possibility to add a discharge-dependent extra cost was implemented in SHOP, where the cost curve can be defined as a piecewise linear function. In an interval around the best efficiency point, no extra cost appears. For lower discharge, the extra cost per hour increases, as illustrated in Figure 19. To ensure that the extra cost is not added when the generator is turned off requires the use of a binary variable for unit commitment which may increase calculation time considerably. In practice, the discharge cost curve should be used together with a minimal production limit and start-up cost.

In the following, the discharge cost curve is defined in the same way as in Eggen (2021), namely with three segments: The zero-cost interval and two segments with slopes 1 EUR/h/(m^3/s) and 8 EUR/h/(m^3/s). The discharge threshold values q_1, q_2 separating the segments varies slightly and will be stated for each test case.

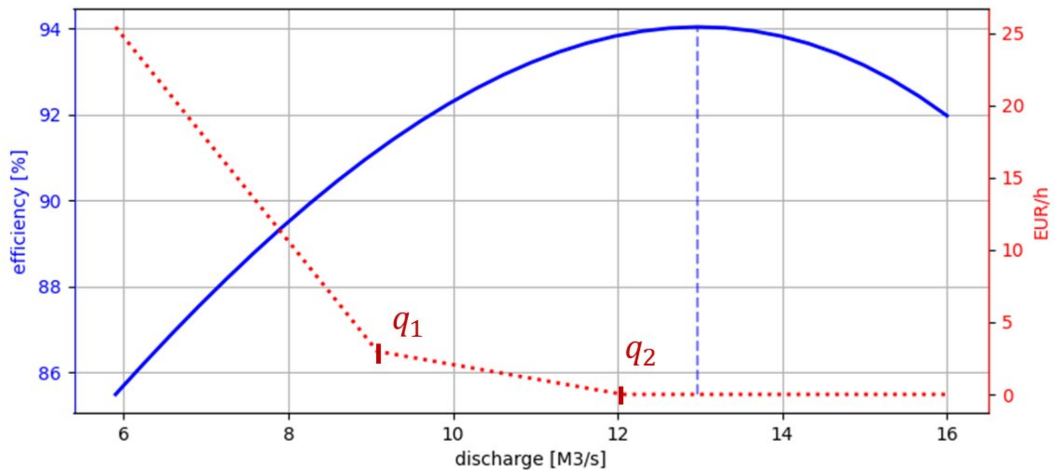

Figure 19. Example of a discharge cost curve (red) in SHOP, together with the efficiency curve (blue). The discharge threshold values separating the segments are marked as q_1, q_2.

4.3.2 Technical verification: test case

The test system is illustrated in Figure 4, and is the same as was used in Sections 3.3 and 4.2.1. As in Section 3.3.1, this two-reservoir system has no head correction, and all components have 100% efficiency. Thus, no best-efficiency point exists, but the system can be used for technical verification. Typically, it is optimal to use the plants either at maximum power or not at all. First, we consider operation without reserves. We compare the production pattern with and without an extra cost of wear at the downstream plant B, with $q_1 = 70\%\ Q_{max}$ and $q_2 = 90\%\ Q_{max}$. In addition, a small start-up cost of 5 EUR and $P_{min} = 20\%\ P_{max}$ are included to avoid any potential numerical issues with the discharge cost near zero. As shown in Figure 20, the impact of the discharge cost curve is negligible, since the optimal solution is not operating in the penalized discharge range anyway. The duration curve has two clear plateaus corresponding to running either one or both plants at P_{max}.

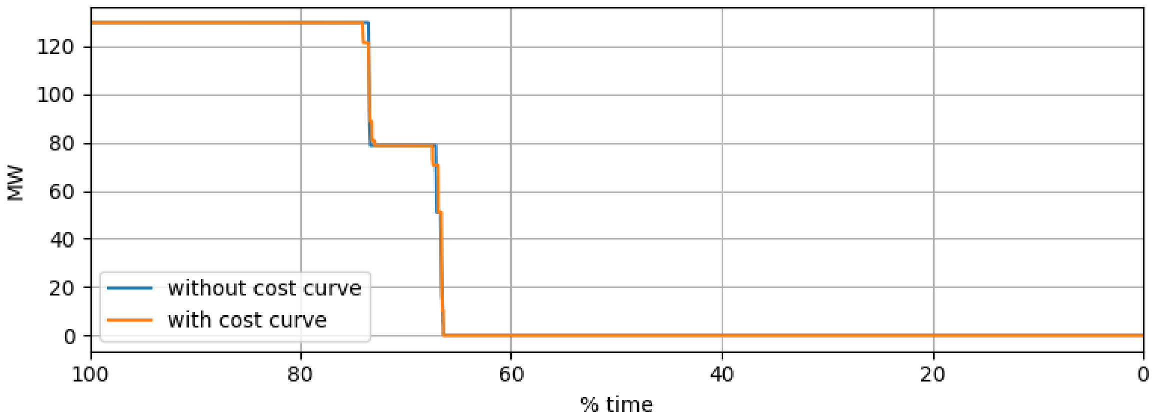

Figure 20. Duration curve for total production in the test case with and without cost curve, without reserves.

Next, we consider the same system including spinning reserves for up-regulation, which can be allocated on plant B. The market volume for reserves is set to 10% of the maximum production of plant B. The case without a discharge cost curve on plant B is compared to two different cost curves: one with q_1, q_2 as in the previous test ("low" curve), and one where q_2 is increased to $95\%\ Q_{max}$ ("high" curve). The resulting duration curves are shown in Figure 21. For the low curve, the onset of extra cost coincides with the maximum allocatable reserve. Hence, the impact of this cost curve is marginal for high plant utilization because reserve allocation is not sufficient to drive plant B into the penalized region (i.e., above 121.8 MW). On the other hand, the low curve has an impact in the low-power range. The spinning condition can lead to situations where the plant is active only to sell reserves, and therefore runs at P_{min} (15.7 MW). This is heavily penalized by the discharge cost curve, leading to a different usage of the lowest plateau in Figure 21.The high curve has roughly the same effect at low power, but also restricts the use of reserves close to P_{max}. The 95%-threshold of the cost curve becomes clearly visible as a new usage plateau (approximately 125 MW).

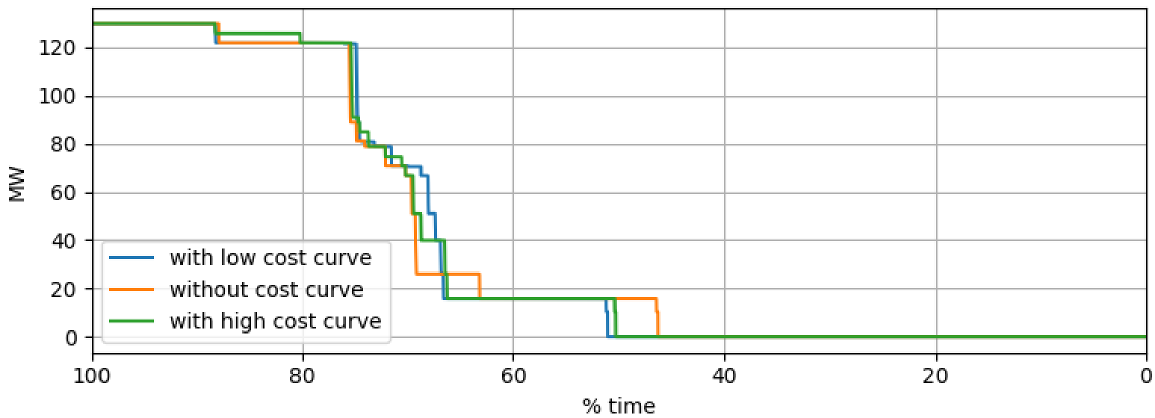

Figure 21. Duration curves for total production of both plants with different discharge cost curves on plant B, with spinning up-regulation reserves.

The total impact of the extra cost becomes clear in the accumulated SHOP results over the entire simulation period as given in Table 2. A stricter discharge cost leads to a minor increase in spot market sales, but a decrease in reserve sales. The total from both markets decreases slightly. The total reserve allocation (the annual average of sold MW times hours in which the reserve was allocated) is significantly reduced by the extra cost.

Table 2. Accumulated base case results with spinning reserves and different discharge cost curves. Differences are relative to the case without cost curve.

	Spot sales [MEUR]	Reserve sales [MEUR]	Tot. sales difference [%]	Total sold reserves [MWh]	Reserves difference [%]
No cost curve	86.565	3.237		24630	
Low cost curve	86.588	3.147	-0.07	22869	-7.04
High cost curve	86.628	3.006	-0.19	20422	-17.08

4.3.3 Test case: East Røldal-Suldal hydro system (East RSK)

After successful verification of the discharge cost for the simple test case, the impact of such costs was analysed for a model of the RSK system. In contrast to Section 4.2.2, only the eastern part of the RSK river system, illustrated in Figure 22, was considered in order to reduce computation times. All generators were connected to the spinning reserve market (up-regulation) and a discharge cost curve was added for each generator with $q_1 = 70\%\ Q_{best}$ and $q_2 = 93\%\ Q_{best}$. Note that both thresholds are now relative to the best efficiency point, instead of the maximum discharge. The best efficiency point is necessarily an approximation, given that the production curve is head-dependent, whereas the discharge cost curve does not have head dependence in SHOP.

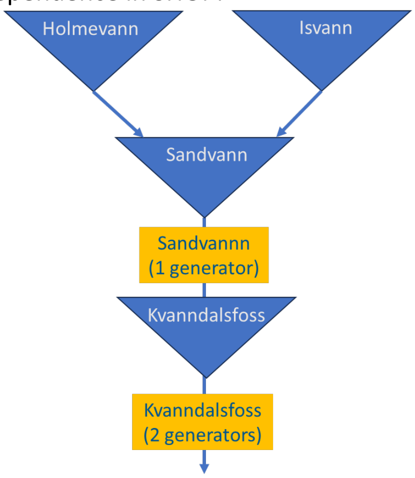

Figure 22. Illustration of the eastern part of the Røldal-Suldal hydro system (East RSK).

In Figure 23, discharge duration curves are compared for the cases (i) without reserve markets, (ii) with spinning reserves without discharge cost, and (iii) with both spinning reserves and discharge cost. The curves are plotted for the Sandvann and Kvanndalsfoss power plants. The cost curve introduces clearly visible new plateaus in the duration curve, e.g., corresponding to the threshold q_2 around $12\ m^3/s$ for Sandvann, because the model tries to avoid the discharge range with additional cost whenever possible. When the cost curves are not included, the duration curves do not exhibit as sharp plateaus due to the head dependence.

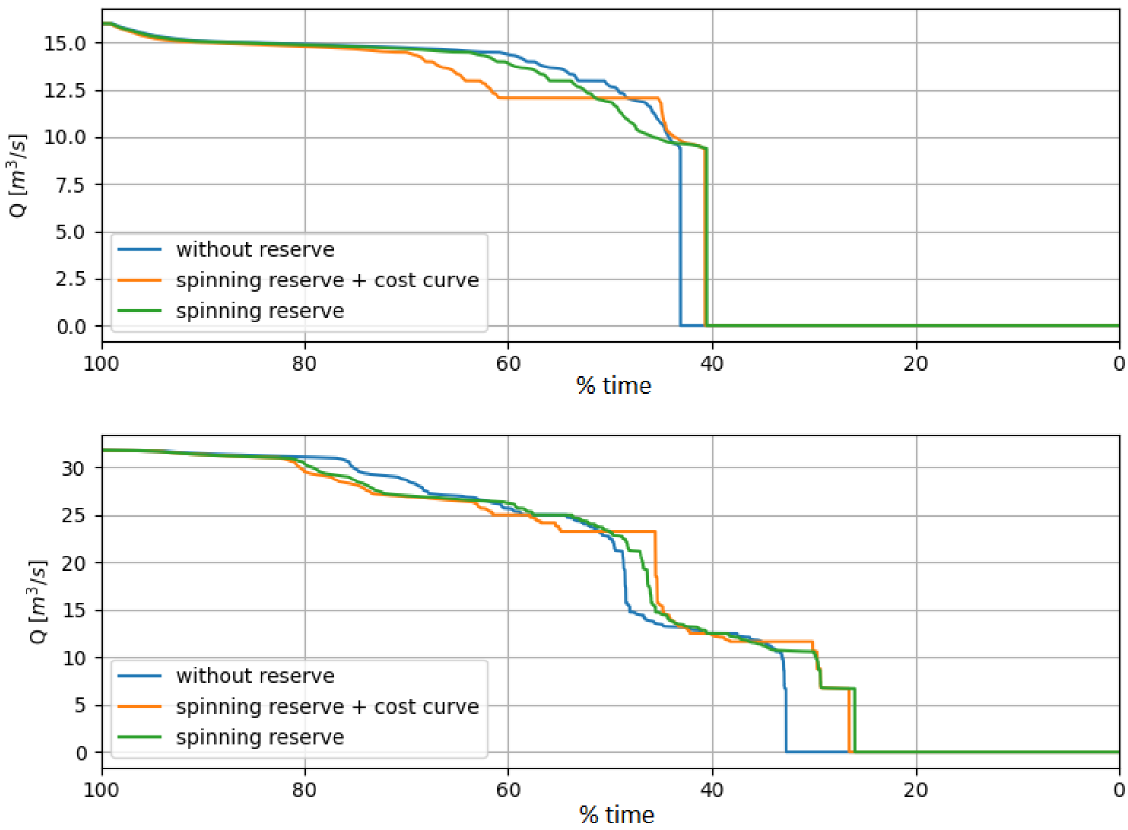

Figure 23. Discharge duration curves for Sandvann (upper panel) and Kvanndalsfoss (lower panel).

Simulations including spinning reserves with and without discharge cost curves were repeated multiple times while varying the price assumptions in two different ways:

1. Scaling the spinning reserve prices with a factor, while keeping the same spot prices. The intention is to study the dependency of sale of reserves on the average price level in the reserve market relative to the spot market.
2. Scaling the spot price deviation per price period (3 hours) relative to the daily average price with a factor (volatility scaling), while keeping the same reserve prices. This gives insight into the impact of short-term price fluctuations on reserve sales.

The final price series are manipulations of the prices used in Section 4.2.2. The results are presented in the following two subsections.

Simulations with scaled reserve price

The scaling factors $f = 0.5, 1, 2, 3, 4$ are used for the reserve price series. The results for reserve allocation and reserve revenue are shown in Figure 24 and Figure 25, respectively. When the discharge cost curve is not included in the short-term optimization, the reserve allocation strictly increases with increasing reserve prices. This is not true for extreme reserve prices ($f = 4$) when the extra cost is added as can be seen in Figure 24. At the same time, as shown in Figure 25, revenue does not seem to be affected by this, indicating that high prices are exploited even more radically.

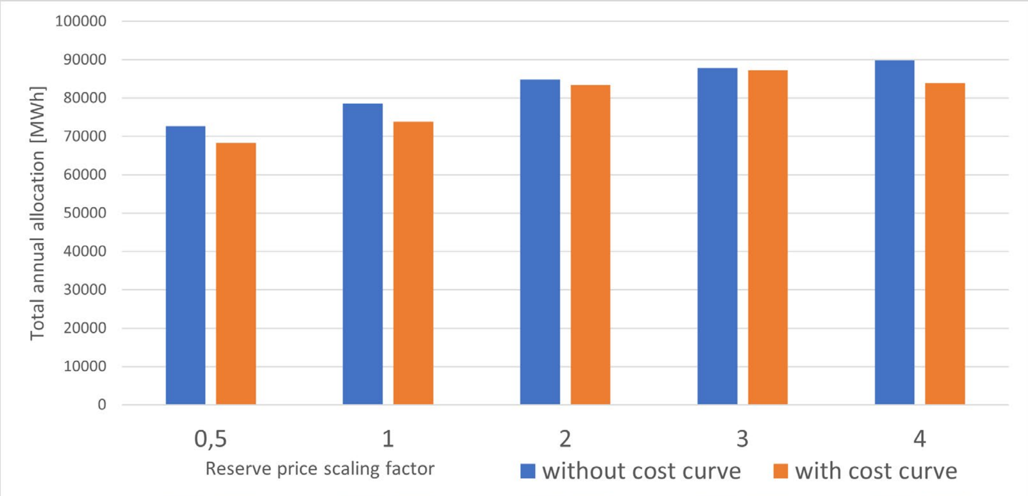

Figure 24. Average annual reserve allocation in MWh for different reserve price scaling factors.

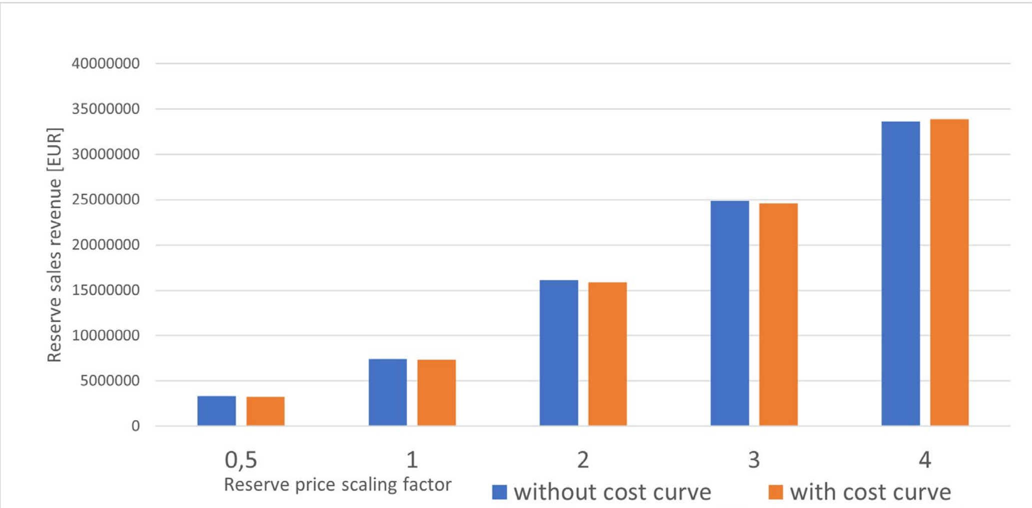

Figure 25. Average annual reserve market revenue in Euro for different reserve price scaling factors.

Based on the assumed discharge cost curve, the accrued cost of wear can be calculated from the discharge results to estimate the expected impact on the lifetime of the generators. The result is shown in Figure 26. In all cases, the cost curve functionality produces a usage pattern that significantly reduces wear. However, this effect becomes less important for high reserve prices. When reserve prices increase while the cost of wear remains the same, this cost becomes less relevant. Note also that the total cost of wear is very small compared to the overall objective value.

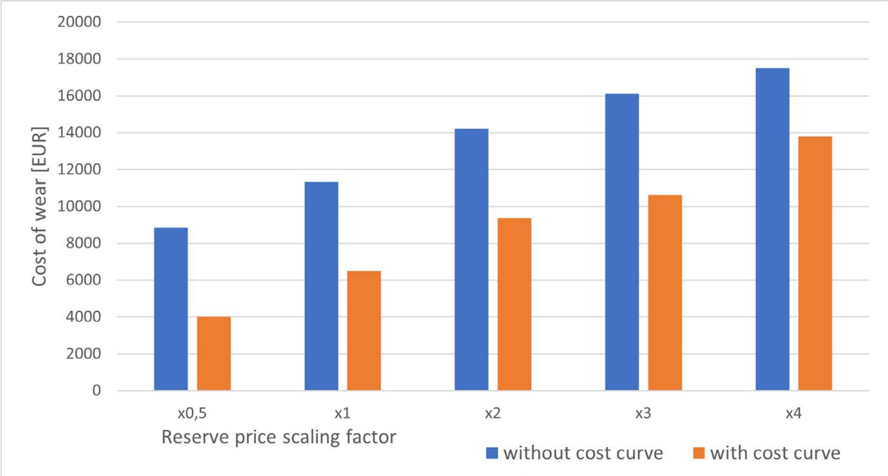

Figure 26. Average accumulated annual cost of wear for different reserve price scaling factors.

Spot price volatility scaling

The volatility was scaled with factors $f = 1,2,3,4$. First, the average price per day P_{day} is calculated from the original price series. Then, for each price period, the deviation $d = P_{period} - P_{day}$ is computed. The scaled price in this period is $P_{scaled} = P_{day} + f \cdot d$. This scaling preserves all daily averages but enhances the intra-day variation of prices (for factors > 1). Figure 27 illustrates the increase in price variability in the scaled price series.

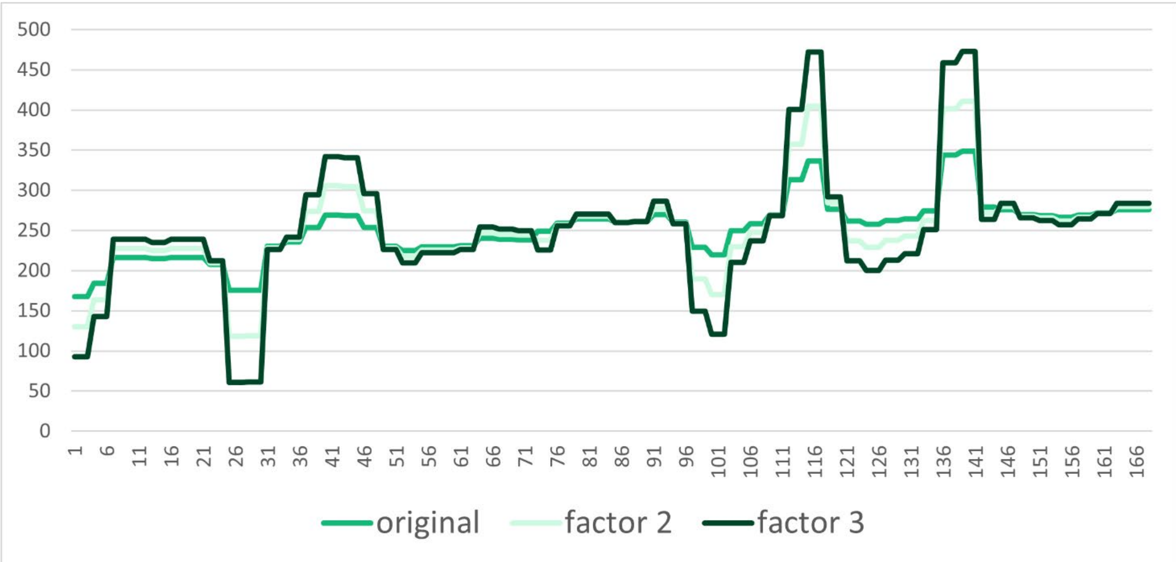

Figure 27. Price volatility scaling - prices (Euro/MWh) per hour during the first simulation week.

From Figure 28 and Figure 29, one can see that the reserve allocation decreases with increasing variations in spot prices. The difference in yearly reserve sales between simulations with and without a discharge cost curve almost disappears for very high spot price volatility. In that case, it is more beneficial to use the available flexibility to adjust the production pattern to maximize the income from the spot price variations, rather than binding up capacity in the reserve market. Both the spinning condition and the discharge cost curve reduce flexibility and therefore make it less profitable to sell reserves in a volatile spot market. In reality, one might expect a correlation of reserve prices and the volatility of the spot price. This was not considered in this study, but the results from the two price cases (i.e., reserve price scaling and volatility scaling) indicate that the two effects could balance each other.

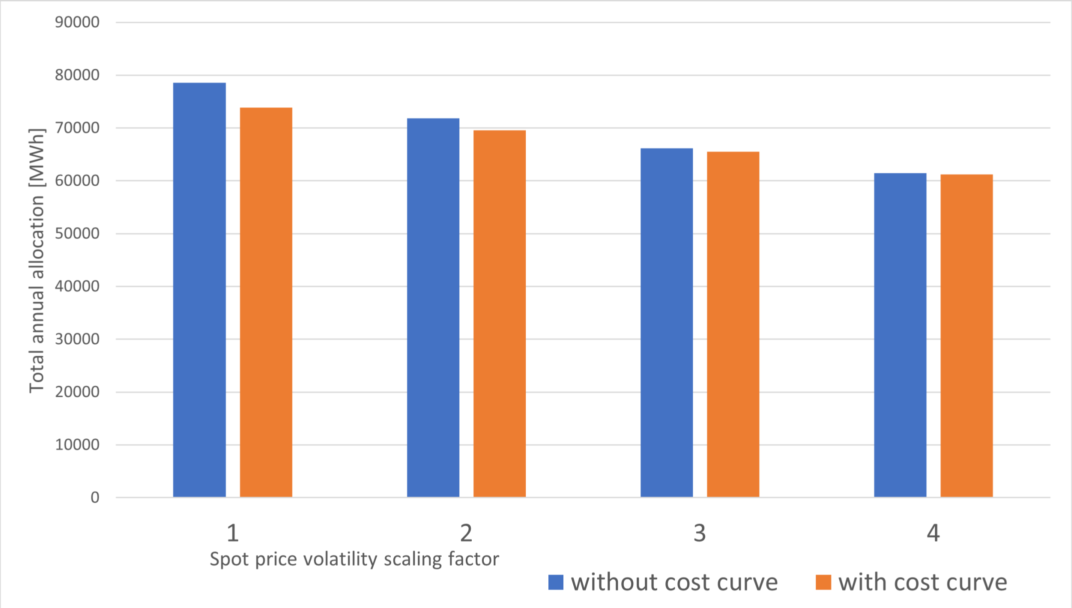

Figure 28. Average annual reserve allocation in MWh for different spot price volatility.

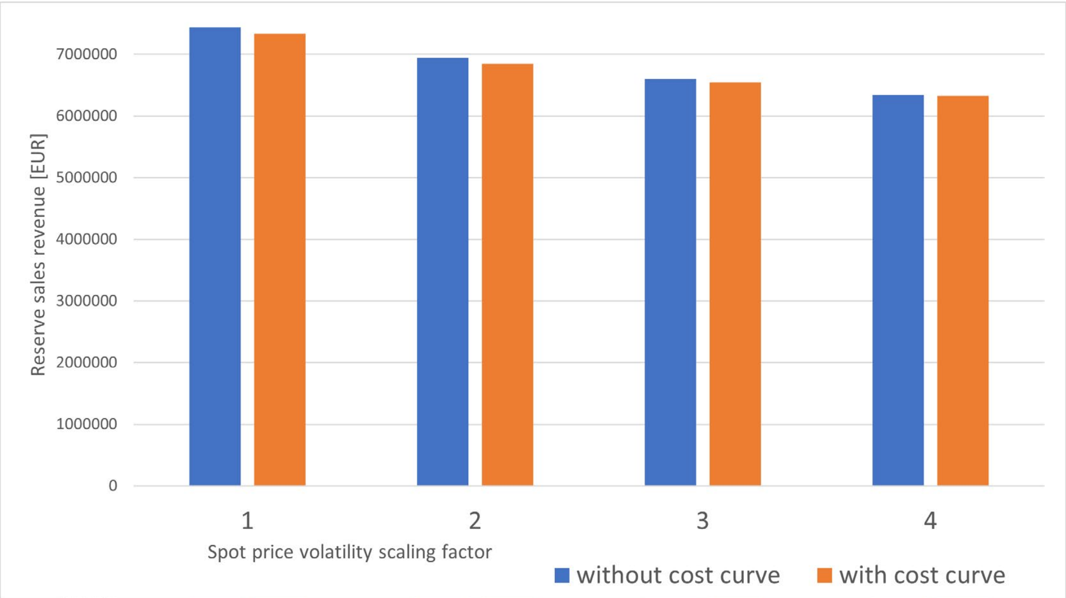

Figure 29. Average annual reserve market revenue in Euro for different spot price revenue.

The cost of wear is shown in Figure 30. As reserve usage decreases with higher price volatility, the total cost of wear is also reduced. The relative benefit of including the discharge cost curve in the optimization is roughly the same (about 50%) for all scaling factors. The cost of wear from start/stop is not included in these numbers.

Figure 30. Average accumulated annual cost of wear for different spot price volatility.

4.4 Reserves in both SHOP and ProdRisk

The simulations of the RSK system, presented in Section 4.2, showed a deviation in the reservoir filling between the short- and long-term model when reserve markets for up regulation were considered in the short-term model. This indicates that the strategy from the long-term model without reserves is not optimal for operation in the short term-model with reserves. This section investigates this further by including reserve markets in the long-term model ProdRisk, as well as in the short-term model.

Furthermore, reserves for both up and down regulation were considered. It is demonstrated that up and down regulation have opposite effects on the water values, which can balance each other to some extent. This is in line with what has been shown theoretically in Helseth et al. (2017):

1. Binding down regulation capacity contributes to higher water values.
2. Binding up-regulation capacity contributes to lower water values.

We demonstrate the importance of including reserves in the water value calculation by simulating for cases with only one type of reserves or both at the same time.

The reserve market functionality in ProdRisk was implemented outside of HydroCen and became first available in 2024. The optimization including reserves is based on the following assumptions and simplifications:

1. There is only one market for up regulation and one market for down regulation. Details of different types of reserves and contracts are disregarded.
2. Decisions on reserve sales and energy sales are made simultaneously with the same time resolution, i.e., the spot price periods are used for the reserve markets.
3. Reserve prices are deterministic to avoid unacceptable computation time, i.e., the same reserve price series is used for each spot-price scenario. Correlations between spot and reserve prices are not considered.
4. Reserve activation is not included.

To achieve as similar reserve modelling as possible in ProdRisk and SHOP, only capacity allocation of non-spinning reserves (i.e., the "RR" market type) was used in SHOP. Identical reserve prices and allocation limits were used in the short- and long-term models.

In the following, we first present results from simulations with the full simulator for the Eastern Røldal-Suldal hydro system to investigate the benefit of including reserves in the water values given to SHOP. Secondly, simulations with ProdRisk only are used to analyse the impact of reserves on the water values.

4.4.1 Test case: East Røldal-Suldal hydro system (East RSK)

Case description

As a test system, the eastern part of the RSK system was used. The system is the same as was used in Section 4.3.3 and consists of 4 reservoirs and 2 plants, as illustrated in Figure 22. In practice, the ProdRisk and SHOP models are clipped versions of the full system shown in Figure 14. Details that are only modelled in SHOP and not in ProdRisk are start-up cost on all generators (treated as binary variables in MIP), more precise representation of creek intakes, physically correct head optimization, and modelling of two separate units in the downstream plant "Suldal II", which is described by an aggregated production curve in ProdRisk. The limit for reserve allocation was set to 20% of the total maximum production. The allocation per plant and unit was unrestricted, such that the models had freedom to distribute reserves optimally. The same reserve capacity was used for up regulation and down regulation.

The price series for the spot price and the up-regulation reserve price are identical to the ones used in Section 4.2, with historical reserve prices for 2022 and spot prices from HydroCen scaled to the historical mean value from 2022. As for up regulation, the prices for down-regulation reserves are historical prices for 2022 taken from Nordpool for NO-2. The price series are shown in Figure 31. In general, the prices for up and down regulation reserves are quite similar. The coherence of the reserve and spot prices is not realistic, but the preparation of prices with correct correlations was outside the scope of this project. In addition, the limitation in ProdRisk that reserve prices must be deterministic does not allow for coupled spot and reserve prices per scenario. The used prices are nevertheless assumed to be suitable to study generic effects of reserve allocation on the optimal strategy.

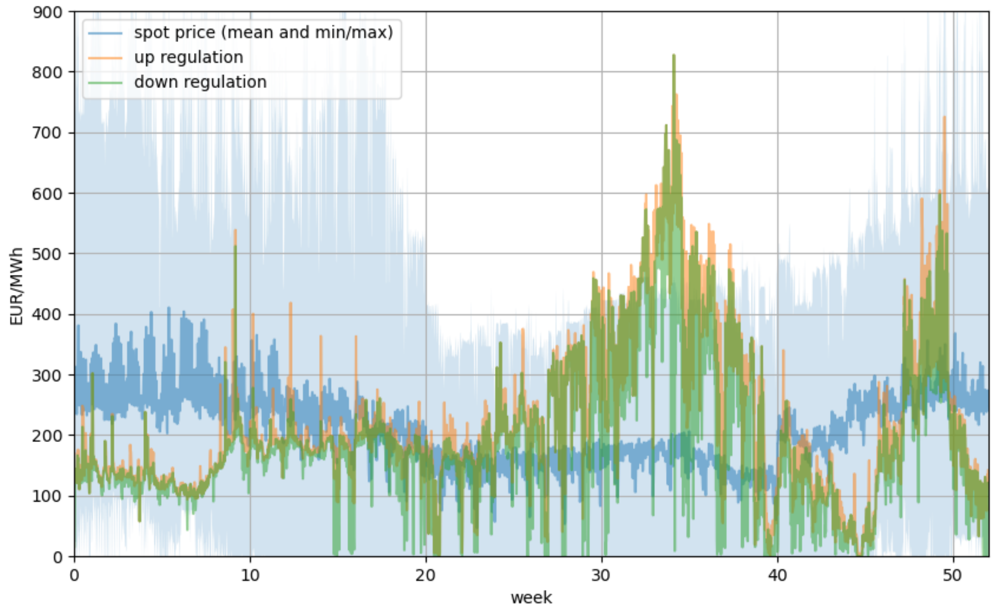

Figure 31. Price series: Spot price with average (dark blue) and minimum/maximum values (light blue), reserve prices for up regulation (orange) and reserve prices for down regulation (green).

The ProdRisk-SHOP simulator was run with different reserve types (up/down/both) in either SHOP only or both ProdRisk and SHOP, in addition to the base case without any reserves. All simulations are summarized in Table 3.

Table 3. Summary of the simulator runs with reserves.

No.	Reserves in ProdRisk	Reserves in SHOP
1 (base)	None	None
2	None	Up regulation
3	None	Down regulation
4	None	Up and down regulation
5	Up regulation	Up regulation
6	Down regulation	Down regulation
7	Up and down regulation	Up and down regulation

Reservoir operation

First, it was checked that the effect observed in Section 4.2 on upstream water storage can be reproduced with the eastern part of the RSK system if reserves are only included in SHOP. The largest upstream reservoir is Holmevann (96 Mm^3). The filling of Holmevann is shown in Figure 32. One can see that, as observed before, the water level increases compared to the base case when reserves for up regulation are added. For down-regulation reserves, the effect is opposite, resulting in less upstream storage. If both reserve markets are included at the same time, the average filling is almost not affected. This confirms that the impact of up and down regulation on water management is roughly cancelled out in a symmetric situation when reserves are not considered in the long-term strategy.

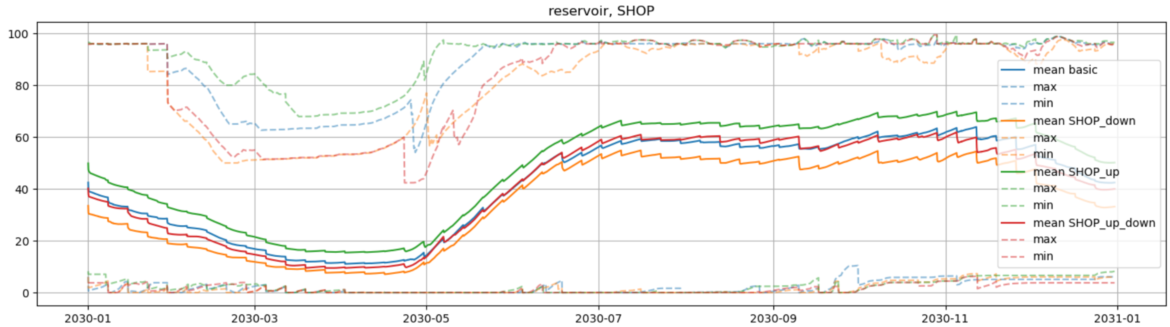

Figure 32. The filling of Holmevann in Mm3 for all simulations without reserves in ProdRisk: no reserves (blue), up regulation (green), down regulation (orange), and both up and down regulation (red).

When reserves for up regulation are included in the strategy calculation in addition to the short-term model, the reservoir management changes significantly. The results from the simulator are shown in Figure 33. The average filling in Holmevann becomes very similar to the case without reserves. This indicates that the increase in filling when reserves are considered in the short-term model is sub-optimal. Furthermore, the maximal filling is reduced when reserves are included in the strategy, narrowing the span of the operational scenarios. Contrarily, with reserves in SHOP only, the model suggests raising the maximal filling before the spring flood period. The reason for both effects (too high average and maximum with SHOP only) is that the short-term profit from reserve sales combined with the incorrect water value (i. e., not considering reserve allocation) provides a too strong incentive to hold back water in the short-term model.

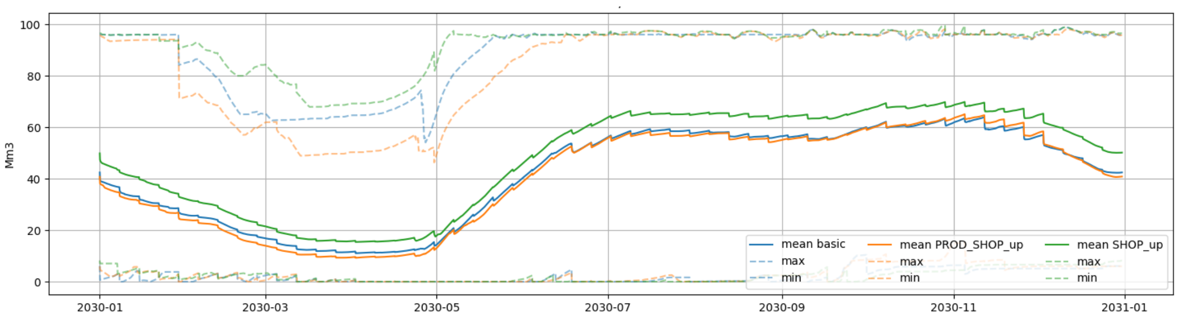

Figure 33. The filling of Holmevann for the simulations with reserves for up regulation in ProdRisk and SHOP (orange), only SHOP (green), or none (blue).

Similarly, with reserves for down regulation, the average filling of Holmevann is much closer to the base case when the reserves are included in the strategy, compared to the results with reserves in SHOP only. Simulator results for down regulation are shown in Figure 34. In contrast to the results for up regulation, a difference to the base case remains. Hence, it is optimal to reduce the stored volume, but the short-term model tends to overestimate this effect without correct water values.

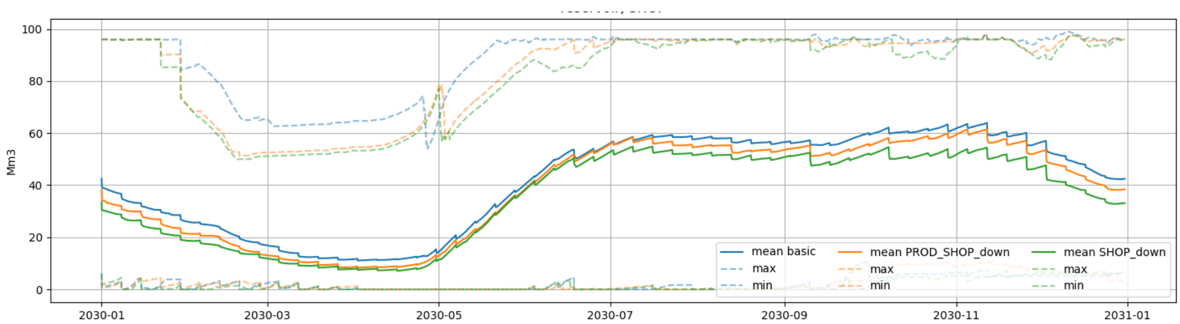

Figure 34. The filling of Holmevann for the simulations with reserves for down regulation in ProdRisk and SHOP (orange), only SHOP (green), or none (blue).

In the symmetric case, where the same reserve capacity can be allocated for both up and down regulation, see Figure 35, the outcome is different. Including the two reserve markets in SHOP only, they roughly compensate each other regarding water management. However, including the reserves in the long-term strategy leads to a reduction of the average filling. Apparently, the sensitivity of the long-term model and the short-term model on the regulation direction is different. This will be discussed later.

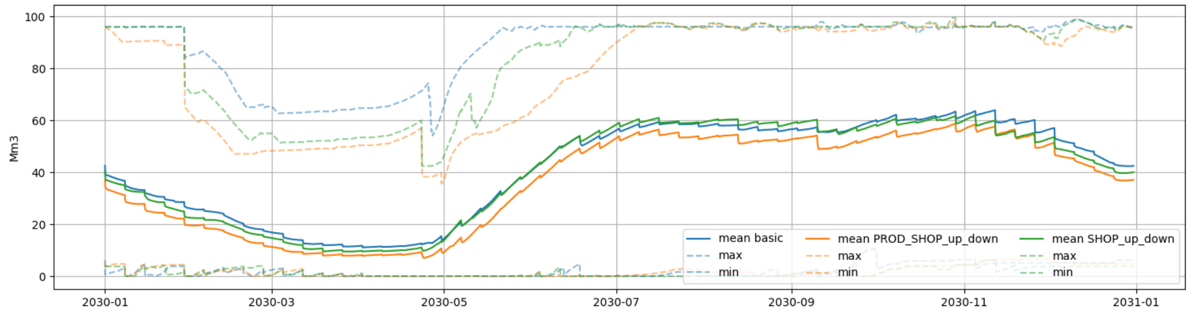

Figure 35. The filling of Holmevann for the simulations with reserves for both up and down regulation in ProdRisk and SHOP (orange), only SHOP (green), or none (blue).

Plant utilization

In Figure 36, duration curves for the total production in the system are shown for simulations with up-regulation reserves. One can clearly see that, in ProdRisk as well as in SHOP, the use time at maximum power is drastically reduced when reserves are included. This is as expected, because up regulation is only possible when the production limit is not fully exploited. Instead, there is a long plateau at the power corresponding to the maximum production minus the maximum reserve capacity. Hence, for a large fraction of time, selling reserves is more profitable than producing the same capacity. Given that activation of reserves is not included in the models, the reduced production at high power leads to surplus water and extended use time at lower prices. The lower half of the duration curve lies therefore higher in the cases with reserves. An important difference between the curves from ProdRisk and SHOP is the abrupt drop to zero at P_{min}, which is only present in the SHOP results but not in the ProdRisk results. This is a consequence of binary variables not being modelled in ProdRisk. Instead, ProdRisk uses a convex production curve, which does not represent unit commitment and minimum power exactly. Whether or not reserves are included in ProdRisk has only a marginal impact on the resulting duration curves in SHOP.

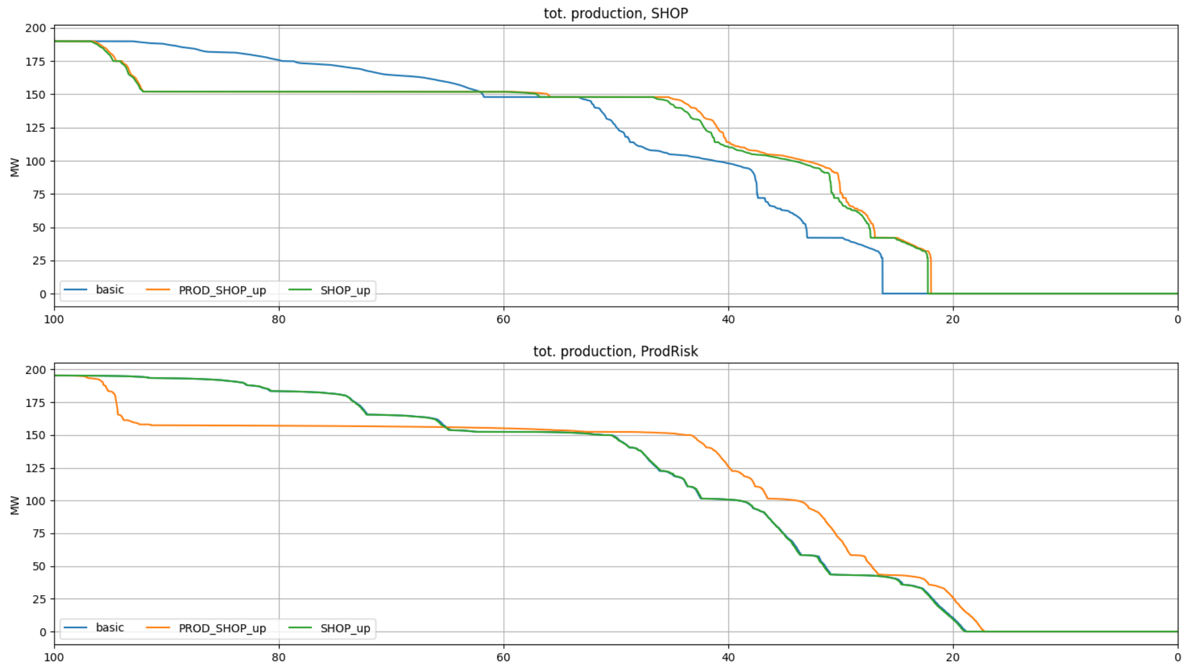

Figure 36. Duration curves for total production in the simulator. Results from SHOP (upper panel) and ProdRisk (lower panel), without reserves (blue) and with up-regulation reserves included in only SHOP (green) and both ProdRisk and SHOP (orange).

For down regulation, there is little effect on the high-power segment of the duration curves, see Figure 37. However, the use time at low power increases such that down-regulation reserves can be sold more often. The total use time in ProdRisk is higher than in SHOP, which can be attributed to the model differences related the modelling of minimum production, start-up costs, and production curves for individual generators in SHOP.

When reserves for both up and down regulation are included, the duration curves exhibit all features discussed above at the same time. Results with both reserve types are shown in Figure 38. In all cases, the total annual generation remains on average approximately the same with and without reserves. This is not surprising, given that the same amount of water is passing through the system.

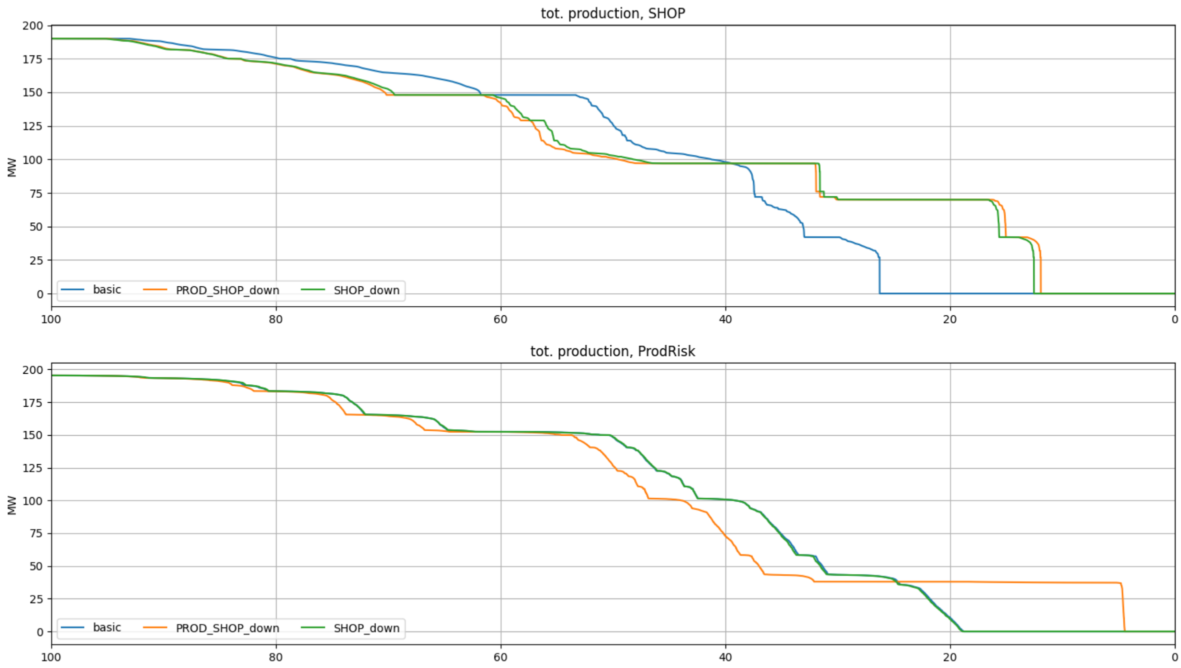

Figure 37. Duration curves for total production in the simulator. Results from SHOP (upper panel) and ProdRisk (lower panel), without reserves (blue) and with down-regulation reserves included in only SHOP (green) and both ProdRisk and SHOP (orange).

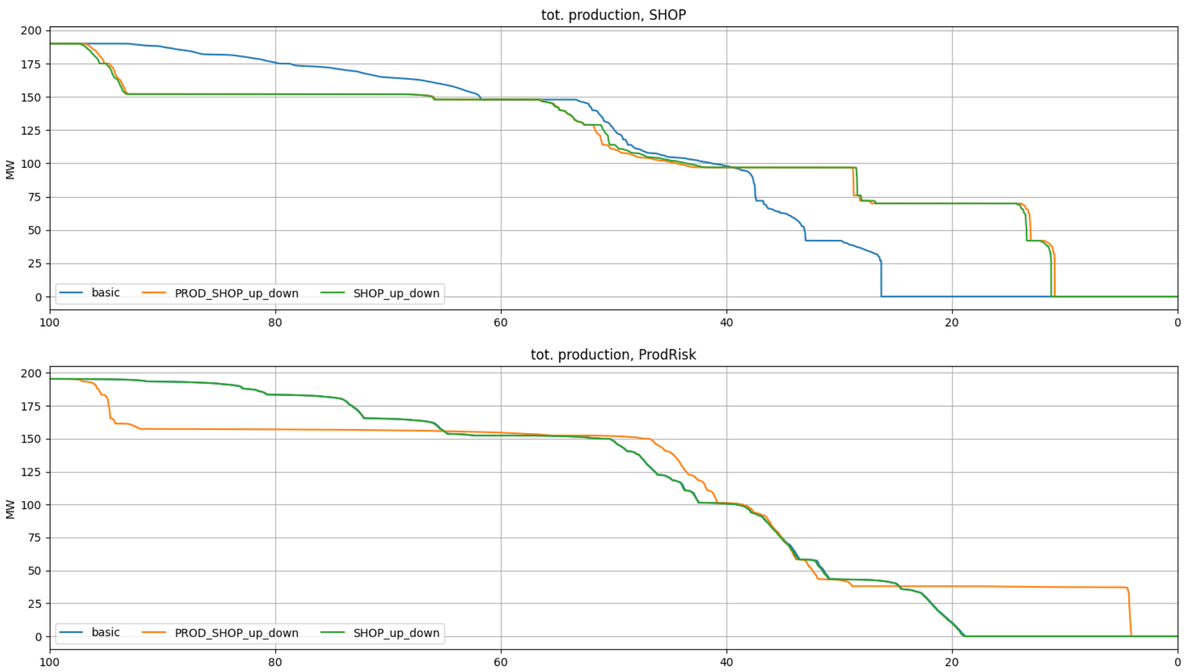

Figure 38. Duration curves for total production in the simulator. Results from SHOP (upper panel) and ProdRisk (lower panel), without reserves (blue) and with up- and down-regulation reserves included in only SHOP (green) and both ProdRisk and SHOP (orange).

In Figure 39, the allocation of reserves is shown. With the prices assumed in this case study, the reserve sales are most of the time close to the allowed maximum, for both up and down regulation. This is similar in all simulations and in both models.

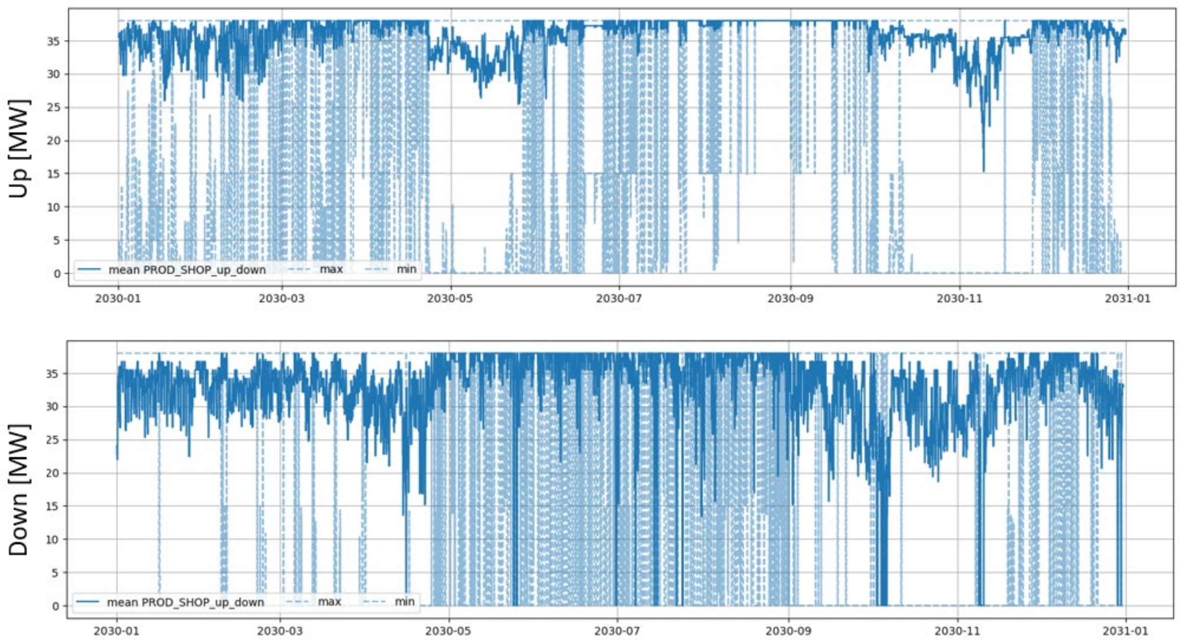

Figure 39. Average (solid) and minimum/maximum (dashed) allocation of reserves for up and down regulation as a function of time for the simulation where both reserve types are included in both models.

Revenue

When reserve markets are included, the spot sales revenue decreases slightly, while substantial additional revenue is generated through reserve sales (roughly 20% extra per reserve market). This is shown in Figure 40. It must be noted that the economic results crucially depend on the price assumptions as well as the reserve market limits, which were arbitrarily set to 20% of P_{max} in this case study. As discussed above, the reserve prices were high enough to exploit most of the available reserve capacity most of the time. The additional revenue from reserves is therefore nearly maximal in this study and might be lower in other cases.

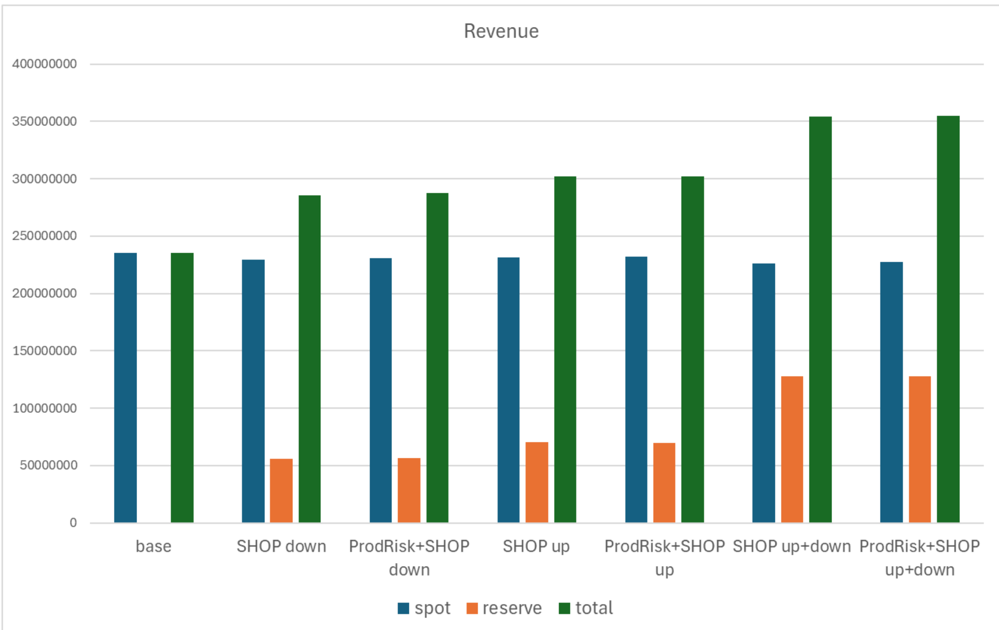

Figure 40. Average annual sales revenue in MEUR from spot (blue), reserve (orange), and all (green) markets for all simulations (cf. Table 1).

To extract the value of including reserves in the long-term strategy, the differences in revenue between the simulations with reserves in both models and the simulations with reserves only in SHOP are shown in Figure 41. The total income increases in all cases and is largest when only reserves for down regulation are present. The difference corresponds to ca. 1% of the total revenue in that case. Including reserves in the strategy yields an advantage in the long-term resource management. For the case shown here reserve markets predominantly affects the income from the spot market but this can be dependent on how the reserve market is modelled and the somewhat simplified deterministic reserve price modelling. For the case with only up regulation, the revenue from reserve sales even decreases slightly to allow for larger income on the spot market.

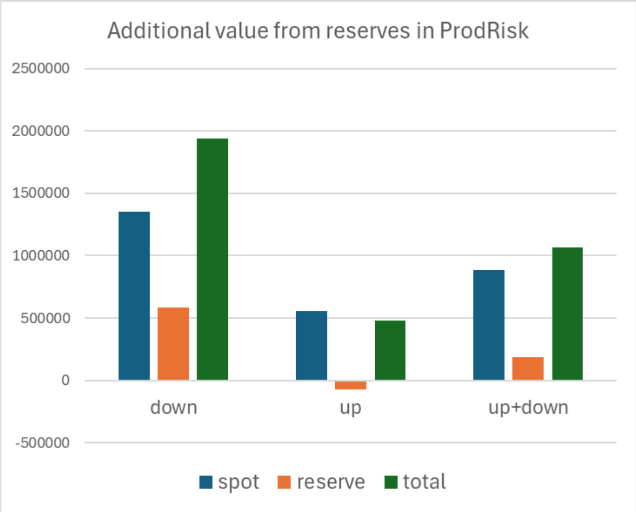

Figure 41. Difference in revenue in MEUR between simulations with reserves in ProdRisk and SHOP and simulations with reserves in SHOP only.

4.4.2 Water value analysis

Including reserves in ProdRisk makes it possible to see how the water values change when reserve market is included. To run ProdRisk multiple times within reasonable computation time, water values/cuts were calculated assuming a deterministic spot price and only one price scenario was used in the final simulation. A series of ProdRisk simulations per reserve type (up, down, up and down) was run with a maximum reserve capacity varying from 0% to 100% of the maximum power. The marginal water values in each week were calculated by applying the cuts computed by ProdRisk to the corresponding system states for all inflow scenarios. Subsequently, the average over all scenarios was taken to obtain the average marginal water value.

Figure 42 shows that the average marginal water values in all reservoirs systematically decrease when reserves for up regulation are included in the optimization. The marginal water value decreases because less water can be discharged when up-regulation reserves are sold, thereby increasing the utilization time and reducing the value (increase in profit) that can be generated from an additional unit of water. Contrarily, Figure 43 shows a systematic increase of water values when down-regulation reserves are considered. In that case, each additional unit of water helps to continuously sustain the discharge needed for down-regulation reserves. This confirms the earlier mentioned theoretical results from Helseth et al. (2017).

As an example, the same information is shown for week 40 in Figure 44 as a function of maximum reserve capacity. While one can see that the water values decrease or increase for up and down regulation, respectively, it is important to note that the relative water value between reservoirs is not significantly changed, apart from fluctuations for the small reservoirs. This explains why the reservoir operation with reserves in ProdRisk in Section 4.4.1 is almost the same as without reserves, although the absolute water values are very different.

The water values in the case with both up and down regulation follow the water values for up regulation for reserve capacities up to roughly 50% of P_{max}, while the impact of down regulation appears to be stronger for very large reserve capacities.

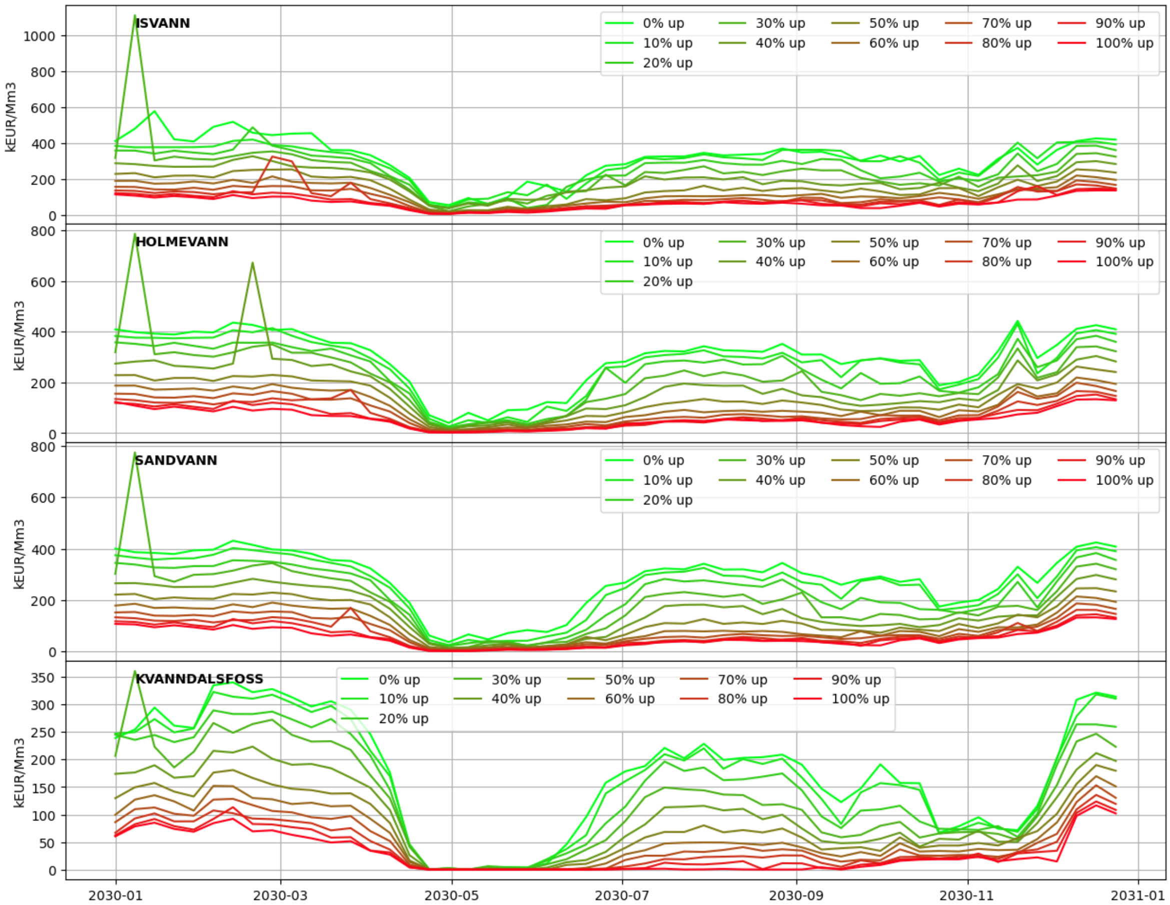

Figure 42. Average marginal water values as a function of time for all reservoirs in the east RSK system when a reserve market for up regulation is included with a maximum capacity varying from 0% (green) to 100% (red) of P_{max}.

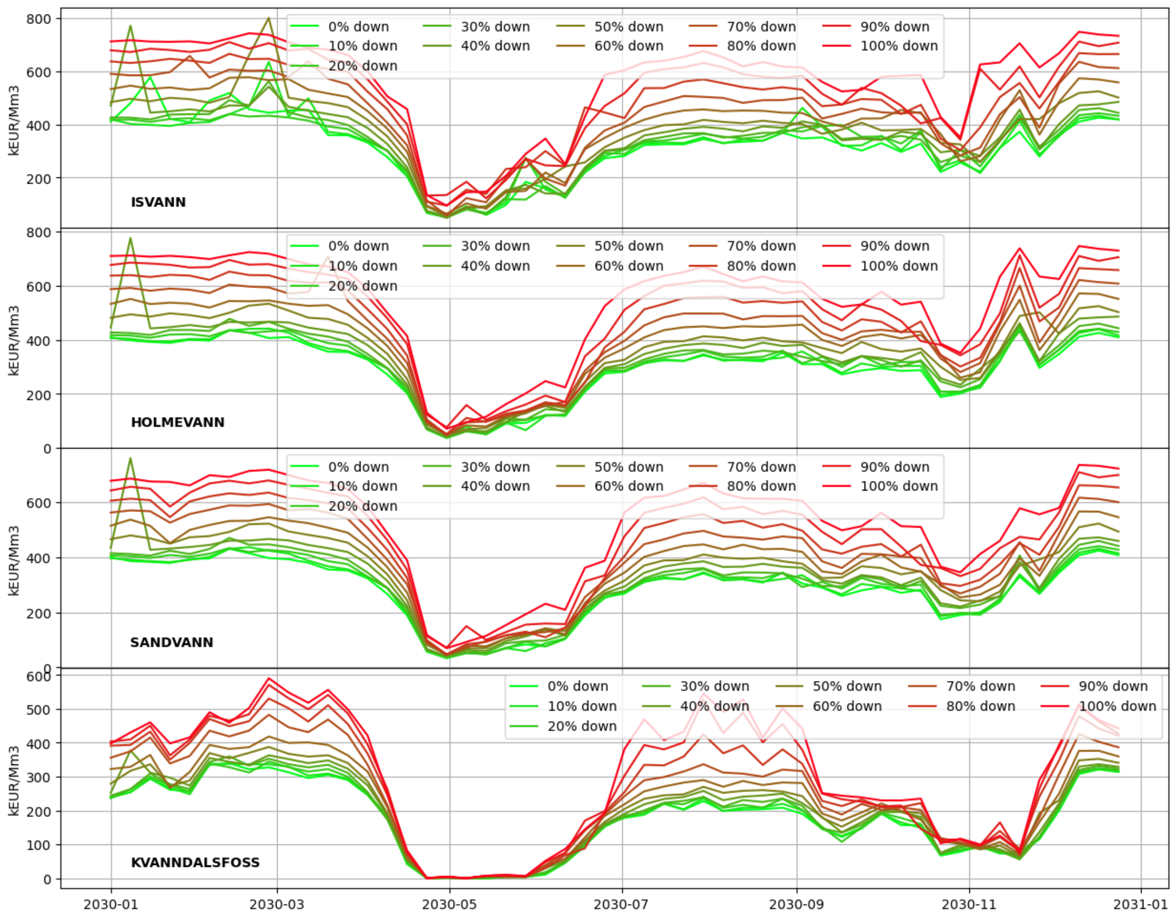

Figure 43. Average marginal water values as a function of time for all reservoirs in the eastern RSK system when a reserve market for down regulation is included with a maximum capacity varying from 0% (green) to 100% (red) of P_{max}.

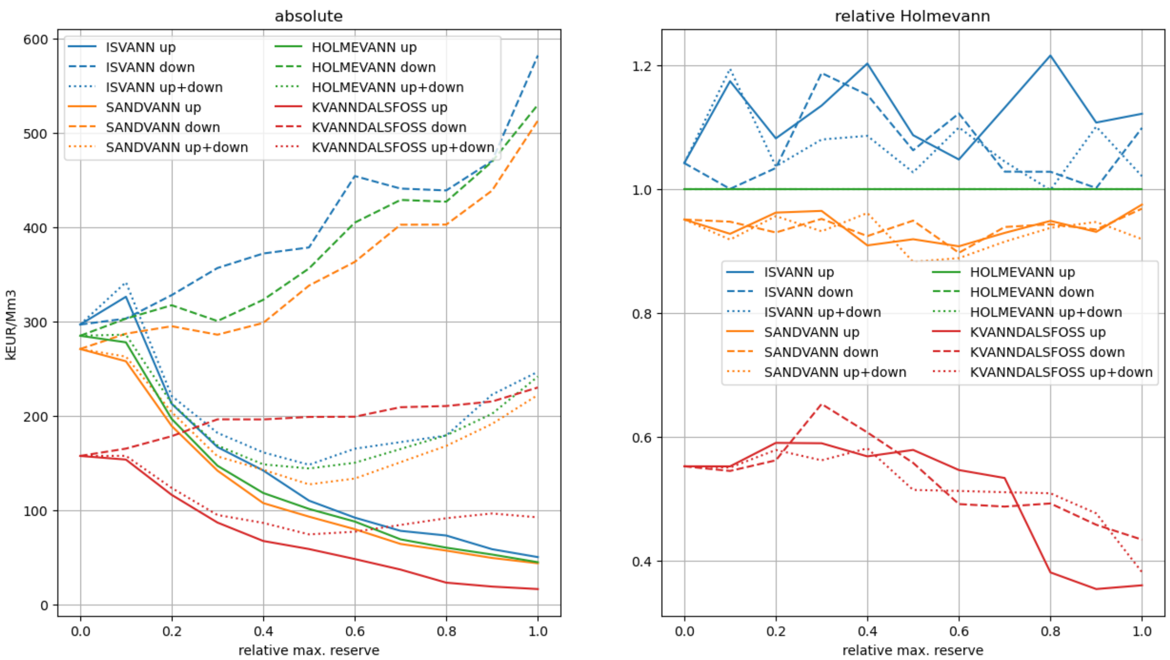

Figure 44. The average marginal water value in week 40 for the different reserve types and all reservoirs, as absolute value (left panel) and relative to the water value at Holmevann (right panel).

Figure 45 shows the water values at Holmevann in week 10 and week 40 without reserves, only up or only down regulation, and both reserve types. Here, the water value is shown as a function of the filling of Holmevann, while a fixed reference filling is assumed in the other three reservoirs. The average fillings over the simulated scenarios in the respective week were used as reference fillings. The reserve capacity was set to 20% of P_{max}. Again, one can see how up regulation reduces the water values, whereas down regulation increases the water values. The shape of the water value functions can be quite different for different weeks during the year, but on a qualitative level the effect is always the same. Given that the reserve capacity is well below 50% of P_{max}, the water values with both up and down regulation follow roughly the water values from the case with only up regulation – as expected based on Figure 44.

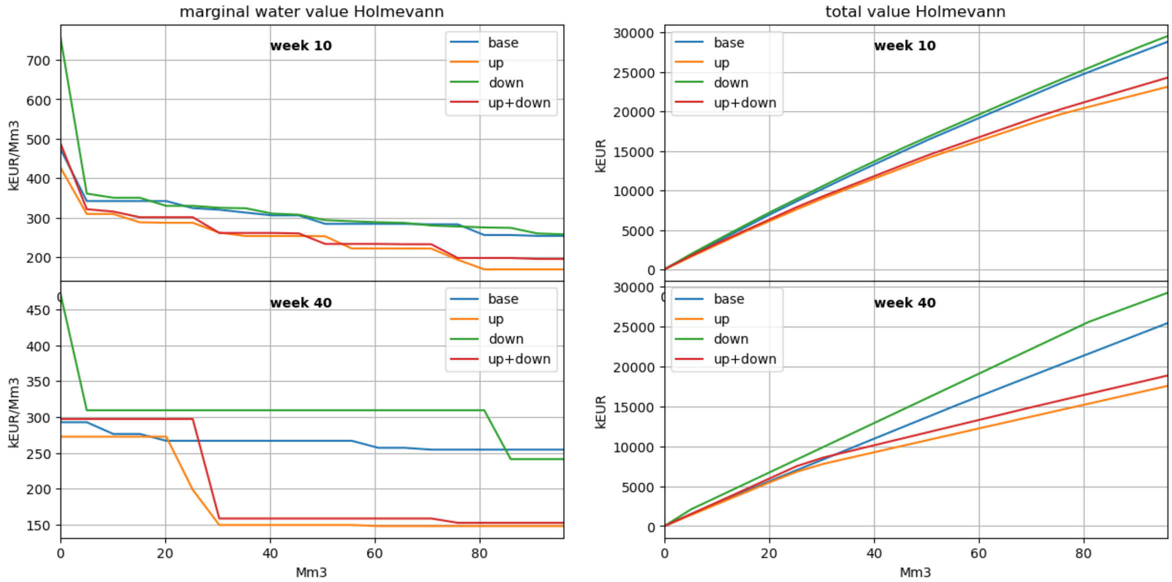

Figure 45. Marginal water value (left) and total value (right) at Holmevann in two different weeks as a function of filling ($V_{max} = 96\ Mm^3$) for fixed reference filling of the other reservoirs.

4.4.3 Calculation time in the simulator

An important aspect regarding the usefulness of including reserves in the simulator is the effect on calculation time. In Figure 46, the calculation times for all complete simulator runs listed in Table 3 are shown. In general, including reserves is computationally costly. With reserves in both models, the simulator run time increases by 38%, 64%, and 102% for up regulation, down regulation, and both together, respectively. It should be noted that complexity of the optimization could be reduced if the models only had to find the optimal reserve capacity but not the distribution on the plants or generators.

Considering the computation times for ProdRisk and SHOP separately, it turns out that up regulation seems to be more difficult than down regulation for ProdRisk, whereas SHOP needs less time for down regulation than up regulation. A possible explanation is that SHOP has a more advanced modelling of minimum production, start-up cost, and reduced efficiency below the best point, which make down regulation more difficult to handle. ProdRisk, on the other hand, is aware of the future risk of spillage, such that it is harder to include up regulation.

Comparing the simulations with reserves in both models versus simulations with reserves only in SHOP, it turns out that the computation time of SHOP is slightly reduced when reserves are included in the strategy. The present case study is, however, not sufficient to draw general conclusions. It is not obvious why each deterministic short-term problem is easier to solve by modified water-values, which only affect the end valuation per week.

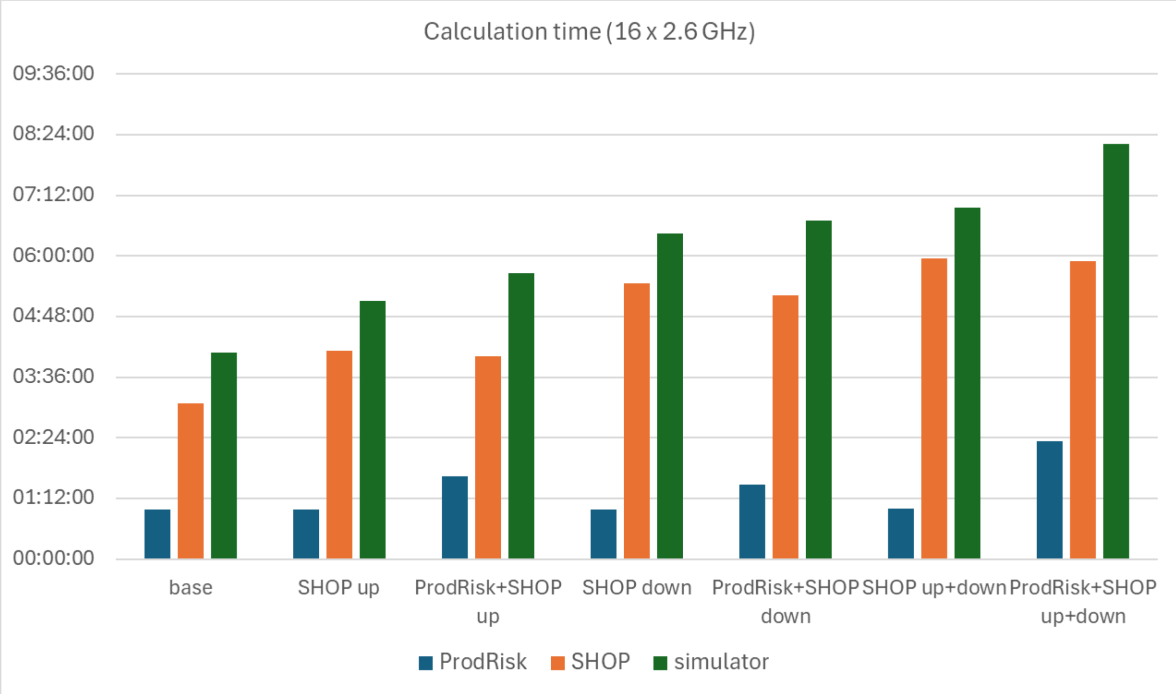

Figure 46. Calculation times for the simulator with reserve markets, tested on eastern RSK with 30 scenarios on 16 cores.

5 Conclusions and further work

This report has summarised the work in Project 3.3 of HydroCen. The project focus has been on decision support for upgrading and investment in hydro power. The project has included one PhD, which has focused on different aspects of the more general investment problem under uncertainty. The research conducted by SINTEF, which constitutes the largest part of the project, has focused on development of a new tool for calculation of production revenues for given production systems. These revenue calculations are important parts of the net present value calculations used in traditional investment analysis.

The new simulator can simulate operation of existing and future hydropower systems, that is closer to real physical operation than what is possible with existing simulation tools. In the first part of the project, we developed and tested the basic simulator framework that is build using two existing operational scheduling models ProdRisk and SHOP. The framework is intended for investment analyses but has also been found useful to test consistency between the two operational models. By checking the consistency in the simulator, errors and inaccuracies in the underlying data can be identified and corrected. Furthermore, the simulator may be used to estimate or adjust certain parameters in the long-term model, ProdRisk, based on the differences between the short- and long-term model in the simulator. This potential of such use could be investigated further.

In project 3.3 of HydroCen, we have developed and tested different improvements of the basic framework. First, we have shown that the simulator results can benefit from updated strategy calculation during the simulation sequence, especially when head dependencies are very important. However, updating the strategy increases computation time substantially. Second, the simulator has been expanded to include a capacity market. With assumed increasing importance of such markets, this simulator functionality will become more important in future. The results show a significant impact on the reservoir management of considering capacity markets in the strategy calculation.

The exiting ProdRisk model assumes a deterministic capacity price and future research should focus on improved modelling of the relation between spot and capacity prices. This includes both estimation of the relationship and implementation in the simulator. Furthermore, the value of ancillary services is assumed to become more important in the future with an increasing share of new renewable production. The value of such services is not covered by the simulator analysis even though this income can be a significant part of the investment analysis. How to calculate the value of such services for a future system is a challenge that likely requires substantial research in the years to come.

Finally, a snipping procedure has been developed, where the simulation is done for a smaller part of the physical water course. This is motivated by reduced computation time, which is an issue using the simulator. We developed the theory and showed that the method, depending on the system and size of the snipped system, reduces the computation time significantly without deteriorating the results. Still, the case study also showed that when snipping a system in the middle of a cascaded water course, the upper and lower modules should consist of reservoirs with some flexibility. Further testing is required to investigate the usefulness and limitations of the method, and to identify potential improvements. Further assessments could include the combination of the snipping functionality and the re-optimization framework to obtain improved accuracy at a lower computational cost.

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Appendix: Available resources: code and documentation of the simulator

The results presented in this report were obtained with a research prototype of the ProdRisk-SHOP simulator. The prototype includes experimental functionality for:

- a snipped system
- re-optimization and updated cuts
- data flow with reserve markets

The prototype can be made available to HydroCen partners upon request, contact stefan.rex@sintef.no.

The basic simulator framework, comprising one ProdRisk series simulation and weekly SHOP simulations, without experimental functionalities, was restructured and published open source. The code, including a basic example, is available as a git repository: https://gitlab.sintef.no/energy/prodrisk-shop-simulator. The simulator requires commercial license for ProdRisk and SHOP.

In addition, the simulator is explained and demonstrated in two videos on HydroCen's Knowledge hub for hydropower https://hydrocen.nina.no/english/.

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