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A case study on medium-term hydropower scheduling with sales of capacity

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Abstract

This paper conducts a case study on hydropower scheduling considering sales of capacity reserves and impacts of detailed modelling. In latter years a growing demand for reserve capacity has been needed to ensure stable operation in the power grid which has given the power producers incentives to commence methods for co-optimization of energy and capacity. In this paper we will assess the value of providing primary reserves and how decisive accurate modelling is for sale of capacity. The results are based on a model consisting of a Strategy and a Simulator part. The Strategy Model is based on a combined Stochastic Dynamic Programming (SDP)/Stochastic Dual Dynamic Programming (SDDP) model where variables and functional relationships are linear. Subsequently the obtained profit-to-go function is used in the Simulator Model; a Mixed Integer Program (MIP) based simulator allowing a more detailed system description. The case study represents a Norwegian water course comprising of two minor and a large regulating reservoir. The Simulator Model manages to incorporate a binary unit commitment and to represent the non-convex relationship between power and discharge, giving more viable results and identifying dependencies between the reservoirs. As a result it was found that the expected profit from sales of capacity was reduced by 40 % when comparing results from the Simulator with the Strategy Model. Correspondingly, sales of capacity gave a clear shift of power outputs between the models as unrealistic results were eliminated in the Simulator Model.

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Keywords: Hydropower scheduling, capacity reserves, Primary Frequency Reserve (PFR) market, Stochastic Dual Dynamic Programming (SDDP), simulator

1. Introduction

For many years the Nordic power market has been isolated from the European continental power grid. The large share of flexible hydropower has secured a stable grid operation and incentives for providing reserve capacity has been scarce. Recent years grid connection to both Denmark and Netherlands has tightened the coupling between the

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systems, belittling the boundary between the hydro and thermal power system. Recent licence to build two new cables to UK and Germany will enhance this effect even further, utilizing synergies between the systems where flexibility and back-up capacity will play an even greater role as the share of intermittent energy resources continue to increase. For a hydropower producer this transition towards the new energy system will require improved scheduling models that can incorporate additional markets.

There has been conducted a large amount on studies regarding the amount of optimal capacity and energy reserves in order to fulfil the system operators requirements to obtain stable grid operation. The authors of [1] investigates the topic with regard to optimal allocation of spinning and non-spinning reserves in a system with a high share of wind on a short-term basis. Co-optimization of both energy, spinning and non spinning reserves was performed through a detailed market representation in [2] where a demand curve for the operating reserves was constructed. The proposed work outlined in this paper will focus on the optimal amount of capacity reserves in regard of a hydropower producer, rather than an optimal overall system optimization, where energy and reserve prices are given as an exogenous parameter.

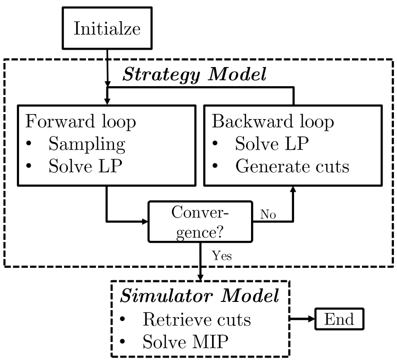
A SDDP model for long-term hydropower scheduling in a hydrothermal system considering sales of energy was proposed by the authors in [3]. Furthermore, a hybrid SDP/SDDP scheduling model was presented in [4] to include spot price uncertainty that has been further developed and in [5] to incorporate scheduling of both energy and Primary Frequency Reserves (PFR). The outlined method described a model that performed a simultaneous optimization, which is a simplification of the original market with sequential allocation. The common factor the above-mentioned papers shares is the requirement of a convex system description with linear state and decision variables.

The novel contribution from this work is to analyze and quantify the impacts detailed modelling imposes when including capacity sales. Long- and medium-term hydropower operational strategies are traditionally found using linear models, and drawbacks with the linear models should be estimated. A Simulator Model is used to evaluate the validity of a linear and convex Strategy Model. The model is performed on the hydro system Lysebotn in the south-western part of Norway. Firstly the weekly generation dispatch is analysed, followed by the simulated marginal cost for providing capacity and the amount of capacity reserves. Lastly, impacts on the duration curve over the period of analysis.

Section 2 contains a brief overview of the applied model and description of the analysed hydropower system. An extensive outline of graphical and quantitative simulation results are given in Section 3 followed by an conclusions in Section 4.

2. Methodology

A thorough outline of the mathematical description and model limitation can be found in [6]. The model has been slightly improved as a tighter bound on the minimum production level when supplying spinning reserve has been



Strategy Model (SDP/SDDP)	***Simulator Model (MIP)***
Objective: Profit maximization	
s.t.	s.t.
Reservoir balance	Reservoir balance
Energy balance	Energy balance
Spinning reserve	Spinning Reserve
Linear start-up cost	Binary start-up cost
Linear hydraulic coupling	Binary hydraulic coupling
Convex power-discharge function	Non-convex power-discharge function Minimim production level

Fig. 1: Overview of the Strategy and Simulator Model presented in this paper.

introduced in the Strategy Model. A narrative representation of the model and case system description is given in the following section.

2.1. Short Model Description

The Strategy consist of a hybrid SDP/SDDP model with incorporation of start-up cost and restrictions on available capacity reserves for sale. The Simulator Model is representing the same physical system and with the same time resolution as the Strategy Model, however with a MIP structure, enabling much higher details in regard to start-up cost, hydraulic connection, representation of the power-discharge function and minimum production level. The forward loop in the Strategy Model provides sampling of spot prices and inflow while the backward loop generates cuts, representing the future profit-to-go function, that is added to the one-stage dispatch problem. The one-stage dispatch problem represents the weekly scheduling problem as the uncertainty in inflow and power price is given with weekly resolution, the week is then divided into 21 time-blocks, all representing a time-block in the 6 different weekly PFR bidding intervals, c.f. [7]. To obtain an equal comparison as possible the exact same sampling of inflow and price scenarios performed by the Strategy Model is applied to the Simulator Model, such that the only difference in modelling is the one-stage dispatch problem. A flowchart of the fundamental model description and how the one-stage dispatch problem is built up can be seen in Figure 1.

The inflow model was based on a first-order autoregressive model, where the statistical properties were extracted from 70 years of weekly inflow data. Day-ahead prices came from a simulation with the fundamental market model Efi's Multi area Power market Simulator (EMPS) [8], while the PFR market price came from historical price data extracted from [9]. PFR market were represented by the historical prices from the years 2013 and 2014. In order to achieve a good comparison in prices as possible the day-ahead prices used came from a EMPS simulation in the start of 2013.

2.2. Case Study Description

A new power station, Lysebotn-2 c.f. Figure 2, is under construction in the hydro system replacing an old one. The input values to the model are hence based on expectations. A slight simplification is made by aggregating the reservoir

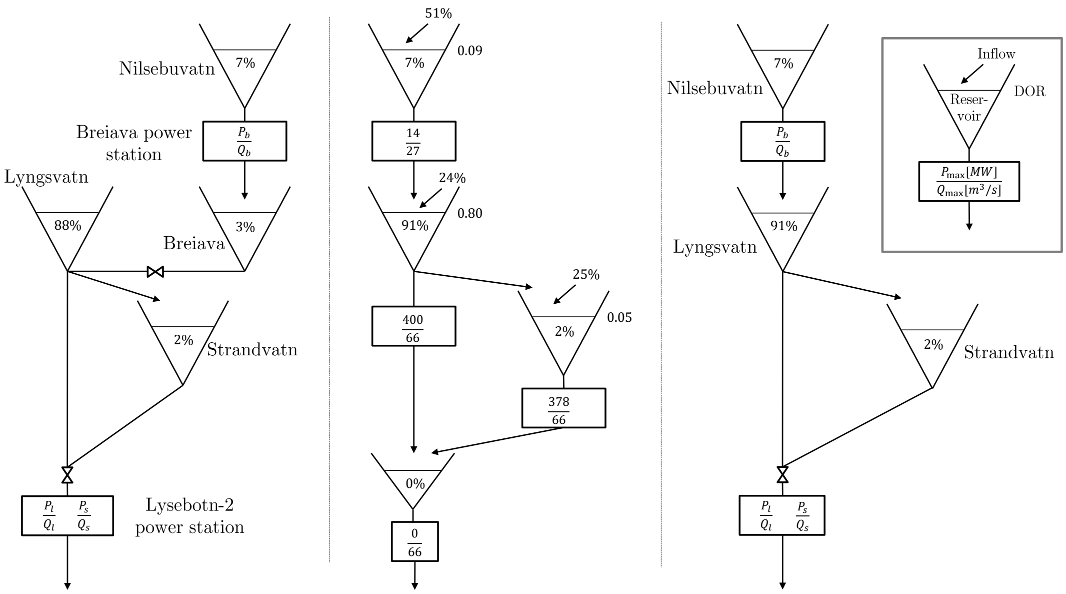


Fig. 2: Physical system (left), Strategy Model system (middle), Simulator Model system with figure explanations (right). Reservoir capacity and expected inflow is given as percentage of the total.

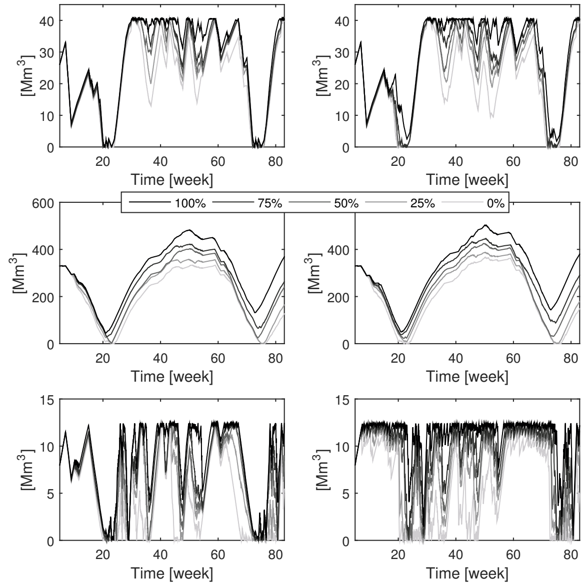


Fig. 3: (Left) Strategy Model. (Right) Simulator Model. Percentile plot of reservoir volume in all reservoirs. (Top) Nilsebutvatn, (middle) Lyngsvatn and (bottom) Strandvatn.

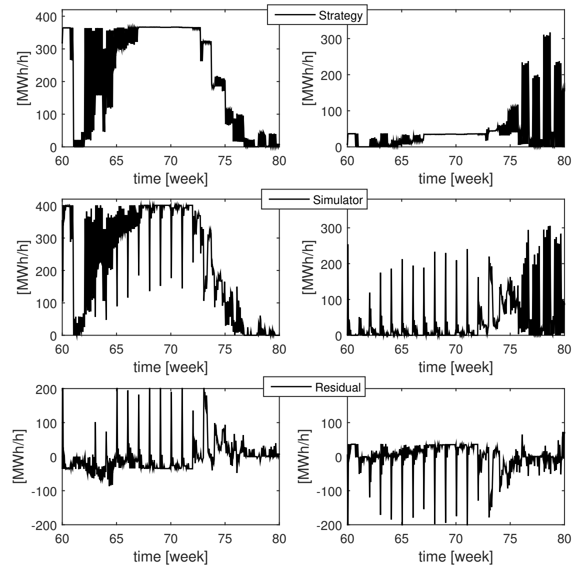


Fig. 4: Production from (left) Lyngsvatn and (right) Strandvatn around from week 60 to 80 for both Strategy Model (top), Simulator Model (middle) and the residual (bottom).

Lyngsvatn and Breiava, while for the Strategy Model a constraint on outflow for Lyngsvatn and Strandvatn is added as the power station, Lyngsvatn-2, can only operate from one reservoir at the time. In the Simulator Model, binary variables were added and hence a rigid unit commitment is obtained. In Figure 2 both expected inflow and reservoir values are given as percentage of the whole system. The Degree of Regulation (DOR) represents how the reservoir size is compared to its annual expected inflow. It can be seen that the upper and lower reservoir act as short-term storages, while Lyngsvatn acts as a regulating reservoir with long planning horizon.

Over the simulation period of two years 50 scenarios were sampled, in the backward iteration 8 inflow samples were applied and there were 7 different price nodes for the day-ahead price. For comparison there were done two simulations of the system; the single scenario where the model had only access to the day-ahead market and a dual scenario where the model had access to both day-ahead and the PFR market. The Strategy Model was not connected to a long-term model, resulting in some complications when calibration the end-of-horizon statement. The following results is therefore given for the first 78 weeks of the simulation, starting from week 5.

3. Results and Discussion

3.1. Dual Case Scenario

A percentile plot of the hydro reservoir handling for the dual scenario is given in Figure 3. It is clear that both Nilsebuvatn and Strandvatn has a much higher utilization of the reservoirs with rapid filling an emptying, whereas Lyngsvatn follows the characteristics of a regulating reservoir; storing water during low price periods and depletion during high price periods.

As seen from the illustration of percentile reservoir filling in Figure 3, the are hardly any noticeable differentiable patterns between the two models reservoir handling. However, there are two observable changes in regard to the production; firstly, due to the rigid production schedule from Lyngsvatn and Strandvatn a much more jagged reservoir filling pattern is observed in the Simulator Model for Strandvatn. Secondly, lower production in the Simulator Model

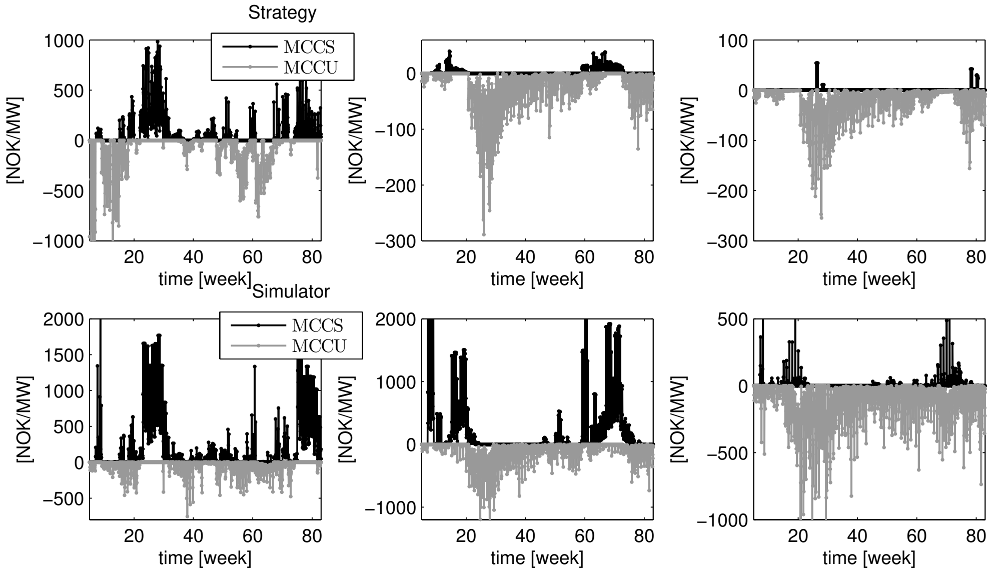


Fig. 5: Simulated marginal cost for capacity reserve for both Strategy Model (top) and Simulator Model (bottom). Nilsebuvatn (left), Lyngsvatn (middle) and Strandvatn (right).

results in an overall higher reservoir fillings as the gain from providing capacity reserves has been reduced due to the tightened system description.

A clear evidence for the above mentioned matter is illustrated in Figure 4, that shows the production from week 60 to 80. Since the Strategy Model could operate from both Lyngsvatn and Strandvatn it tended to operate at the best point of Lyngsvatn and with the rest of the available water capacity from Strandvatn. It could then sell energy from both reservoirs and still provide PFR. Similar the start-up cost is also held at a modest level. The production pattern for the Simulator Model differs significantly. As it is no longer possible to operate the power station from both reservoirs the model will now have to switch between them. In addition a constraint on minimum production level is added, ensuring proper utilization of the power aggregates. The Simulator Model therefore chooses to produce at higher power outputs for short time-periods. This will subsequently result in less capacity reserves available and increased start-up costs. This effect of increasing costs of providing capacity reserves can be seen in Figure 5, where the simulated marginal cost of providing capacity are significantly increased. Both Marginal Cost of Capacity Spinning (MCCS) and Marginal

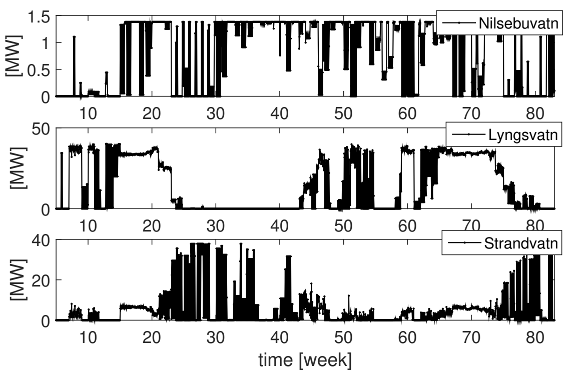


Fig. 6: Sales of capacity reserves for the Strategy Model.

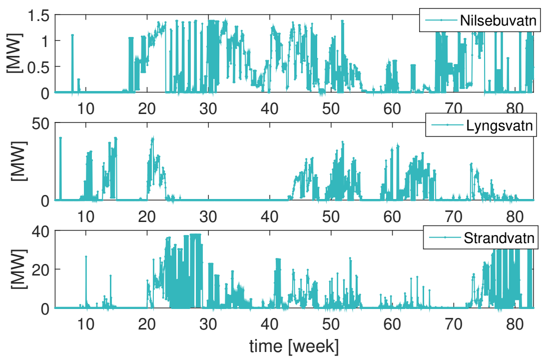


Fig. 7: Sales of capacity reserves for the Simulator Model.

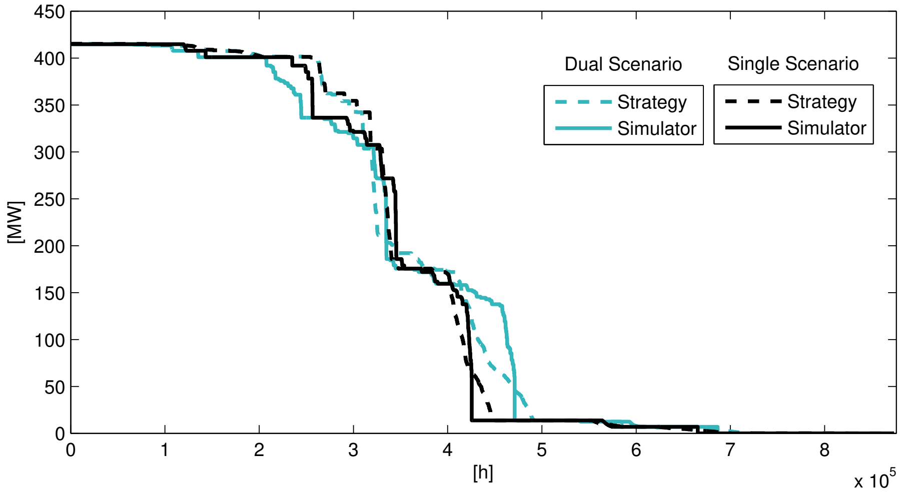


Fig. 8: Duration curve for all market scenarios and models. The duration curve displays values for all power stations in the power system.

Cost of Capacity Up (MCCU) respectively the simulated marginal cost of moving the power station set-point up and down. This comes as a result of the restriction that the power station has to supply symmetrical amounts of capacity. The positive values of MCCS and negative value of MCCU indicates the change in profit obtained if the set-point was increased by one unit. In Nilsebuvatn a considerable increase of profits would be obtained if additional capacity was available in the Strategy Model, which can be seen as a result of the high degree of inflow and minor installed capacity in the power station. As Strandvatn and Lyngsvatn were no longer able to deliver a sufficient amount of capacity, added capacity from Nilsebuvatn would have been highly favourable and hence and the magnified spike of MCCS in the Simulator Model.

The scheduling change in the Simulator Model between Lyngsvatn and Strandvatn from week 60 to 80 is distinctively represented by the high MCCS in both reservoirs. How this affected the actual sales of capacity reserves is shown in Figure 6 and 7, respectively from the Strategy and the Simulator Model. It is evident from Figure 6 that the period around week 20 and 70 served as high income periods from both the day-ahead and PFR market. Nevertheless, in the Simulator Model operation from Lyngsvatn and Strandvatn was not allowed, such that in order to avoid spillage production was set to maximum and almost no sale of capacity reserves were observed.

3.2. Case Scenario Comparisons

Figure 8 depicts the different duration curves of sum hydropower generation for the different models and scenarios, indicating the impact both a dual scenario and detailed modelling has on the hydropower scheduling. From the single to the dual scenario the Strategy Model shows a small shift from production around 350 MW, to a larger amount around 170 MW and down. A similar effect is seen for the Simulator Model, then however the shift in production comes from high power outputs around 400 MW to increased outputs around 150 MW, which has a favourable operating point in regard to efficiency. Both indicating the influence a capacity reserve market constitute, with higher amount of low power outputs.

For the dual scenario the low power outputs around 40 MW in the Strategy Model has almost completely dispersed in the Simulator Model to outputs around 150 MW. This follows from the previous discussed results from the production scheduling in Figure 4. The amount is however modest as the tightened constraint on the spinning reserve at minimum production level has performed well.

In Table 1 some of the important performance and economic factors are displayed. With a total amount of 3.00 TWh generated electricity over the two year period and profit of 1 213 MNOK the average day-ahead price obtained for the Strategy Model would be around 400 NOK/MWh.In the dual market scenario the model tended to store more

Table 1: Overview over significant results for scenario with and without sales of capacity. For comparison reasons the objective value is given by the lower objective value. Values in [MNOK] and [GWh].

	Single market		**Dual market**	
	Strategy	Simulator	Strategy	Simulator
Objective Value	1 418.90	1 410.74	1 447.64	1 436.01
Total Generation	3 002.78	2 960.31	3 060.01	3 014.06
Energy Profit	1 212.52	1 195.55	1 251.97	1 232.87
Capacity Profit	-	-	25.09	15.06
Terminal Value	207.75	217.09	190.22	200.83
Total Profit	1 420.27	1 412.64	1 467.28	1 448.76
CPU Time	7 h 37 min	33 min	10 h 37 min	39 min

Table 2: Percentage differentiation between the different models and different market scenarios.

Comparing	**Strategy $\mapsto$ Simulator**		**Single $\mapsto$ Dual**	
	Single	Dual	Strategy	Simulator
Objective Value	-0.58	-0.80	2.03	1.79
Total Generation	-1.41	-1.50	1.91	1.82
Energy Profit	-1.40	-1.53	3.25	3.12
Capacity Profit	-	-39.98	-	-
Terminal Value	4.50	5.58	-8.44	-7.49
Total Profit	-0.54	-1.26	3.31	2.56

terminal water, which is the value of the water left in the reservoirs after the simulation period, and thereby reducing the profits compared to the single market scenario. In order to compare both scenarios the terminal values of the water were calculated, and hence the model calculated overall total profit gain of 3.31% and 2.56% for respectively the Strategy and Simulator Model. Compared to the Strategy Model obtained the Simulator Model a reduced total expected profit of 0.54% and 1.26%, respectively for the single and dual scenario. It should be pointed out that the objective value includes a number of penalty function and the terminal value of water and is hence somewhat lower than the total profit.

It is clear that there is a profit potential for co-optimizing energy and sales, though limited and with added complexity. The detailed modelling also shows that the actual profit potential is significantly lower than the Strategy Model produces, with a total capacity profit reduction of 52%, c.f. Table 2.

As a result of added options by the PFR market the CPU time was somewhat increased. All simulations were carried out on a Intel Core i7-4600U processor with 2.7 GHz clock rate and 16 GB RAM. It would be reasonable to assume that an parallel processing implementation of the model would significantly reduce computation time [10].

4. Conclusion

The case study presented in this paper has assessed the differentiation in hydropower scheduling between a energy only and energy with sales of capacity scenario. The analysis was performed with the SDP/SDDP based Strategy Model and the Simulator Model, which is a more accurate model of the physical system. The study has achieved to give a quantitative valuation of including sales of capacity and the impact a detailed system description impose. It should be noted that the findings from the paper may be case specific, considering that coupling between reservoirs strongly influenced the results.

Firstly, a short description of the applied model and case study was revised. Following results on reservoir handling and production scheduling were outlined with a discussion on validity, the value of providing capacity was discussed where findings showed a strong link between two of the reservoirs and how this was encapsulated in the detailed modelling. It showed that the Strategy Model overestimated the amount of available capacity reserves. This was especially evident in periods where prices where beneficial but risk of spillage resulted in maximum production and sales of energy only. Lastly, a thorough comparison of the two case scenarios were carried out. It were deducted that the total profit from the dual scenario were 3.31% and 2.56% higher than the single scenario for respectively the Strategy and the Simulator Model. The profit from capacity sales alone were reduced by 40% in the Simulator Model, hence quantifying the impacts of detailed modelling.

The evidence from this case study indicates that The Simulator model proposed promising results in regard to validity of the scheduling and numerical values. The robustness and comprehension of the results could however be improved by drastically increase the number of sampled scenarios. This would however come at the expense of even longer CPU time, but could i.e. simulate with a modest sampling amount and in the last iteration increase it significantly.

It should be addressed that the profit-to-go function is not the true one for the Simulator Model. The importance of generating viable cuts should hence be emphasized . Other important considerations are the amount of volume allocated in the PFR market and the validity of using historical PFR prices, further work should therefore consider these limitations and investigate improvements.

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