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Scheduling when reservoirs are batteries for wind- and solar-power

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Abstract

In this paper we take the perspective of a competitive hydropower producer located in Southern Norway, and calculate the profitability of investing in a pumped storage facility in price-scenario for Europe in 2050. A methodology to analyze the combined supply of day-ahead energy and real-time balancing is described and applied. A sequential optimization for optimal supply in each market is applied, utilizing the same resource cost for hydropower. When supplying balancing energy in addition to the supply in the day-ahead market, total income increase by only 2.2 %. However, the additional income because of the investment increases by 21 %.

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1. Introduction

With the increasing shares of varying wind- and solar-power in Europe's power generation, the balancing of production towards consumption becomes more challenging. Reducing the cost of further integration of renewable energy is also an important motive for the ongoing liberalization and harmonization of markets of electric power and ancillary services in the EU. With the 3rd energy package, formal responsibilities were given to European regulators

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in ACER and system operators in ENTSO-E to develop EU legislation through network codes when the European Commission ask for this. The integration process then changed from being voluntary and intergovernmental to becoming legally binding for member states [1]. Whereas an integrated European day-ahead market for electric power already has been established, network codes are being developed also for intra-day markets and reserve markets (procurement and activation) [2]. Integration of markets supporting ancillary services is however challenging, and integration is foreseen to be implemented step by step.

In a well-functioning European power market, different technologies will compete to balance renewable generation. Examples of technologies include gas-power, demand flexibility, and various storage technologies such as batteries, power to gas, heat storage, and pumped storage. Existing conventional reservoir hydropower can also be utilized for balancing; with or without extra pumps. The storage capacity in existing Norwegian hydropower reservoirs is about 84 TWh, which is about 50 % of total capacity in Europe. The normal-year natural inflow to the existing system was 130 TWh in 2012, which coincides with and domestic gross consumption that year [3].

Several research projects in recent years have focused on how the Norwegian hydropower-dominated power system can be used for the balancing of European renewable generation. A technical potential to develop 20 GW extra hydropower capacity, of which 10 GW pumped storage, was identified in [4]. That study was followed-up in [5], which analyzes the impact of pumped storage on water level fluctuations in reservoirs. A methodology was developed to derive a likely operation of pumped storage, which was taken to come on top of current operation for three existing power plants.

In our study, we have applied an existing tool for hydropower scheduling to calculate the optimal operation in a river system. The profitability for an investment in a new pumped storage facility is calculated for historical prices in the Nord Pool system, and for 2050 scenario. A methodology to evaluate a strategy for the combined supply in the day-ahead market and the market for activation of reserves is described and applied.

Whereas our study focuses on the profitability for an investment in pumped storage for given price-scenario, [6] compares the costs of Norwegian pumped hydro for providing peaking power against OCGT and CCGT. Multi-market studies with detailed hydropower modelling have also been carried out before. For instance, [7] analyses the optimal supply of reserve energy in a short-term model, post to the settlement of obligations through the day-ahead market. A deterministic model for optimal operation of a pumped storage hydropower plants in day-ahead market, power reserve market and markets for activation of reserves is described in [8], with a case-study for Spain. An overview of different markets in the Nordic system, the decision-making process and corresponding models are provided in [9]. A review of optimal bidding in subsequent markets are provided in [10], with some further references to the gains of participating in intra-day markets and balancing markets.

This paper is organized as follows. In Section 2 we describe the applied tool for hydropower scheduling, and the proposed methodology to evaluate a strategy for supply in several markets. Price-scenarios for 2050 are discussed in Section 3, whereas the studied river system and the considered investment project are described in Section 4. Section 5 shows and explains results from the study. Focus is on profits for pumped storage investment, and changes in generation profile. Concluding remarks are in Section 6.

2. Methodology

2.1. ProdRisk model

ProdRisk is developed by SINTEF Energy Research, and used by many hydropower producers. It is a program for long- and mid-term hydropower optimization and simulation based on stochastic dual dynamic programming (SDDP) [11], which enables optimization with stochastic inflow to a large number of reservoirs. The solution approach combines system simulation (operation) with strategy computation. The strategy is represented by so-called cuts, which show the value of water as a function of reservoir levels. In brief, this separation is achieved by dividing the overall problem into smaller optimization problems, which are solved by using linear programming and coordinated by using on the principle of Benders decomposition [12]. In the following we use the phrase water values instead of cuts when referring to the value of water. The model needs time-series for power prices as part of the input, cf. Section 3.2. On this basis, stochastic prices can be included in strategy calculation either by integrating the principle of stochastic dynamic programming (SDP) in the SDDP scheme, or planning can be based on expected

values for future prices. We have applied the latter in this study. The time resolution can be down to 1 hour, with a horizon of e.g. one year. A more comprehensive description of the modeling framework is provided in [13].

2.2. Several markets

The standard version of ProdRisk takes a price-series for one market as an input. In the following, we describe how the model has been modified to analyze a strategy for the participation in the day-ahead market and a market for activation of replacement reserves (cf. definitions in [2]), which also have been called tertiary reserves (see e.g. [14]). The approach is based on the two simplifying premises: a) The supply for the day-ahead market in any given hour is calculated as if it was the only price for this hour, and b) the actual production in an hour can be optimized at prices for reserve energy, treating the day-ahead supply as a financial position taken. Step 1: The strategy (cuts, representing the future value of water), and the optimal operation is calculated. For this simulation we utilize prices for activation of reserves. Step 2: For the strategy and reservoir level developments calculated in Step 1, the optimal supply for day-ahead market prices are calculated for each week. Step 3: The supply of reserve energy is calculated as the difference between the amounts calculated in Step 1 and Step 2. If the actual production calculated in Step 1 is above the amount supplied in the day-ahead market from Step 2, the difference is upward regulation provided, and vice versa for downward regulation. In (1), x^{da} and x^{res} is the quantity produced at day-ahead market prices and replacement reserve prices respectively, whereas Δx is the corresponding supply of reserve energy (up or down).

$$\Delta x = x^{res} - x^{da} \quad (1)$$

Total revenue for a single hour is given by (2). Symbols R , p^{da} and p^{rr} are revenue for a given hour, price in day-ahead market, and price for reserves respectively.

$$R = p^{da} x^{da} + p^{rr} \Delta x \quad (2)$$

The advantage with this methodology is that it can be implemented in existing scheduling tools such as ProdRisk. Moreover, the evaluated multi-market strategy is simple and fairly reasonable: The day-ahead market is treated as the main energy market, whereas production is adjusted up or down in real time if this gives additional profits. Still, the strategy is not fully optimal since the supply in the day-ahead market does not account for possible prices that can be realized for activation of reserves. On the other hand, [10] conclude that there are few results reported that indicate a gain of coordinated bidding.

3. Price scenario

3.1. HydroBalance scenarios

The project CEDREN HydroBalance considers the feasibility of considerable expansion of flexibility and pump-storage in the Norwegian power system [15]. The answer to the question: "What strategy should Norway apply, expand or not?" will have different outcome depending on the expected future development. The HydroBalance project draws a sample space with the purpose of investigating the robustness of the strategy choice. The scenarios differ from each other regarding mainly three aspects:

- Grid expansion between Norway with the power markets of Central Europe and the UK
- Additional generation capacity for Norwegian hydropower, including pumped storage
- To which extent there is cross-border trade only day-ahead, or also e.g. for reserve products.

Prices have been calculated for the two scenarios Big Storage and Niche Storage. Both scenarios include a considerable increase in generation capacity for Norwegian hydropower and corresponding transmission capacity. In the Big Storage scenario, European power markets are fully integrated, whereas only day-ahead markets are integrated in Niche Storage. Also in other aspects the Big Storage scenario is somewhat more favorable than Niche Storage with respect to the conditions for Norwegian hydropower in providing balancing for Europe. See [16] for a description of the methodology leading to HydroBalance scenarios, and a specification of four different scenarios.

The quantification of Big Storage and Niche Storage for the European power system in the year 2050 is mainly based on the EU trends study [17]. The most important adjustment of the scenario concerns the Norwegian system, and installed capacity for renewable generation in other European countries. The EU trends study assumes a rather

moderate expansion of wind and solar power and reaches greenhouse gas emissions targets by nuclear power generation and carbon capture technology. Since these expectations do not seem to fit the current development, RES capacity is increased and nuclear capacity is decreased in the quantification of scenarios. The underlying assumption for the parametrization is that Germany reaches its target of an 80% share of RES generation related to the load in the year 2050 and that the other countries increase their RES capacity regarding the EU trends values to the same extent.

Fuel prices are also taken from the EU trends study and experience a strong increase, e.g. up to 36 €/MWh for natural gas and 75 €/t for greenhouse gas emission certificates. The applied expansion of transmission capacities bases on the ENTSO-E Ten Year Network Development Plan [18]. From and to Scandinavia, transmission capacities are adjusted to sufficiently allow a full utilization of hydropower capacity. Table 1 summarizes differences in main assumptions between Big Storage and Niche Storage.

Table 1. Differences in main assumptions between Big Storage and Niche Storage

	Big Storage	Niche Storage
Conventional generation	<ul style="list-style-type: none"> • 60 GW of hydropower in Norway • Secured peak load in Europe 	<ul style="list-style-type: none"> • 50 GW of hydropower in Norway • Secured peak load for each country
Alternative flexibilities	<ul style="list-style-type: none"> • Little Demand Side Management (DSM) and inflexible Combined Heat and Power plants (CHP) • No power to gas storages • Passive operation of distributed storages 	<ul style="list-style-type: none"> • Increased DSM and flexible CHP • 20 GW of power to gas in Europe • Market-orientated operation of distributed storages
Transmission capacities	<ul style="list-style-type: none"> • ENTSO-E values + 50 % • 30 GW of cables in the North Sea 	<ul style="list-style-type: none"> • ENTSO-E values • 25 GW of cables in the North Sea
Integration of markets	<ul style="list-style-type: none"> • Cross-border reserve markets 	<ul style="list-style-type: none"> • National reserve markets

3.2. Price simulation

The price simulation consists of a two-staged approach. In the first step, European fundamental market simulations are carried out for both scenarios. These simulations perform a cost-minimization in an hourly resolution under consideration of load coverage, RES feed-in and reserve demand as well as technical constraints [19]. Due to complexity reasons, only aggregated reserve power demand is modeled. Main results are the hourly power plant dispatch, power exchanges and day-ahead spot market prices for climate years 2007-2011. The second stage of the price simulation is a more detailed cost-minimization simulation for the German market area for climate year 2008. Power imports and exports at the German borders are adapted according to the European simulation results. This simulation has a 1/4-hourly time resolution and considers different reserve qualities and reserve power activations [20], including the German market for tertiary reserves / replacement reserves, and day-ahead market.

3.3. Transforming output from price-simulation to ProdRisk input

From the price-simulation described in Section 3.2, there are price-series for Norwegian day-ahead prices in 2050 for Niche Storage and Big Storage for climate years 2007-2011. We add a third scenario which is the historical prices in the Nordic system for those years [21]. Reserve prices are calculated only for Germany. However, in the Big Storage scenario there is a full integration of European electricity markets. Markets are also coupled by 30 GW cables in the North Sea. We therefore take the simulated reserve prices for Germany as a proxy also for Norwegian reserve prices in this scenario.

Even though prices for several reserve qualities are calculated for Germany, we utilize only prices for activation of replacement reserves (also called tertiary reserves). In general, the harmonization of markets for reserve energy, i.e. activation of reserves, is less controversial than harmonization of markets for reserve power, i.e. procurement of reserves. Notably, all available capacity can be activated during operation, and not only procured reserves.

There are simulated prices and quantities for upward and downward regulation for each 15 minutes. This is transformed into one hourly price series for ProdRisk by taking the average of price of either upward or downward regulation, depending on the main direction. Due to the transformation of the prices, in a few cases the price for

upward regulation is lower than the day-ahead market price. To avoid adjustments in the opposite direction of the need in the system for hydropower, the price for balancing energy are for such cases replaced with the day-ahead price in the input-series to ProdRisk, and vice versa for downward regulation. Fig. 1a shows the Norwegian day-ahead prices in two scenarios as well as historical values for climate years 2007-2011. Simulated prices for activation of replacement reserves in the main direction for climate year 2008 are also shown. The highest reserve prices are almost 500 €/MWh in a few hours. Fig. 1b shows the variability for prices within a single week. Day-ahead prices for the future scenario are significantly higher than today's values due to rising fuel prices, and fluctuation is higher. It is also clear that the within-week variability for reserves fluctuates more than day-ahead market prices. Due to the assumed flexibility within the European power system, most of the RES generation can be integrated into the markets and thus day-ahead prices only rarely reach zero.

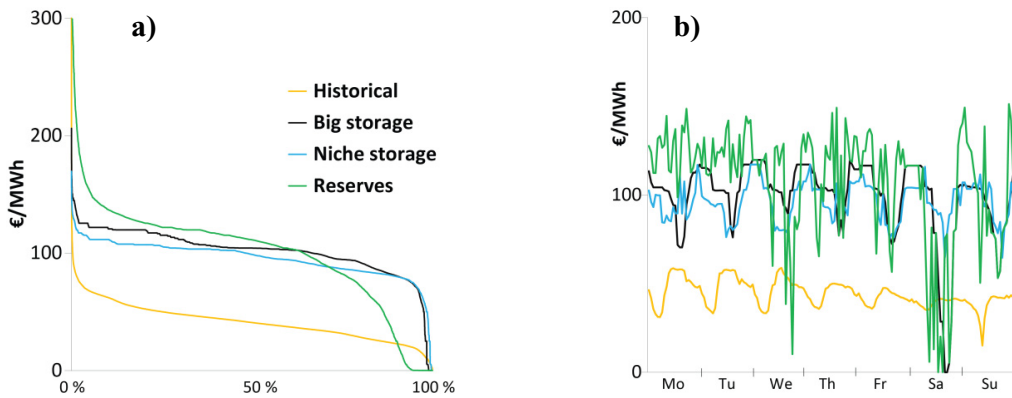


Fig. 1. (a) Duration curves for prices, and (b) price variability within a given week

4. Otra river system

The Otra river system is located in southern Norway (Fig. 2a) with a total watershed of 3560 km². The upper part (Fig. 2b) is well regulated with the power plants Holen and Brokke. The lower part consists of 6 run-of-river plants. The total reservoir-capacity in the river is 2167 Mm³ (3.75 TWh). The biggest reservoirs are Vatnedalen, Botsvatn and Urevatn with a capacity of respectively 1150 Mm³, 296 Mm³ and 238 Mm³. Average annual inflow is around 5 TWh, whereas total generation capacity is 1122 MW.

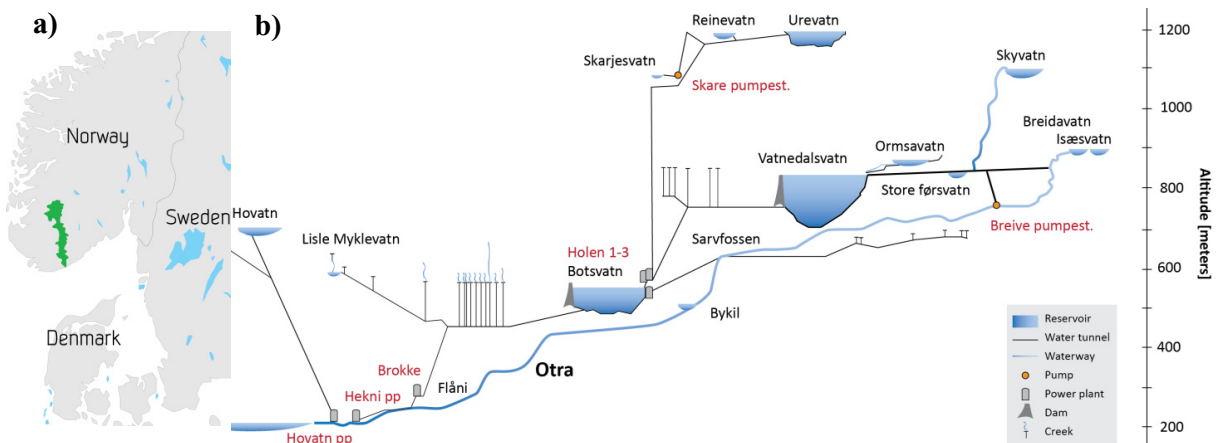


Fig. 2. Sketch of Otra. (a) Location in Southern Norway (in green), and (b) upper part of river system

In Otra river system there are many places where pumped storage plant (PSP) can be developed. Holen 3 is an existing power plant between Urevatn and Bossvatn with 165 MW turbine capacity, cf. Fig. 2. We have considered a project which gives 1000 MW increase in capacity and 1000 MW pump in Holen 3 described in [4] and [5].

It will take about 15 days to emptying or filling these reservoirs with full production/pumping. In our study we assume 85 % efficiency in pump and turbine, which gives 72.25 % as the total efficiency in the PSP cycle. This is in the middle of the range estimated for PSP [22]. The investment cost for Holen 3 has been estimated to 416 M € [23], or 416 €/kW, which is above the interval 250-400 €/kW reported for Norway in [24]. With a 5 % discount rate and 40 year life expectancy, the annualized cost is 24 M € / year.

5. Simulation results

5.1. Motivation for the set of cases simulated

A set of cases is simulated to show the impact changes in prices from historical values to several future scenarios, and the impact of participation in the market for activation of replacement reserves. In section 5.2 we describe results for different price scenario when the producer supplies electricity only to the day-ahead market. In section 5.3 we evaluate a multi-market strategy.

5.2. Supply for the day-ahead market

In this section we report results when the producer supply only for the day-ahead market. Each case includes a simulation with and without the new 1000 MW pumped storage facility at Holen 3. The simulated operations for all cases are illustrated in Fig. 3. Panel a) shows that the extra capacity and the pump are utilized more in future scenario than at historical prices, in particular when the producer participates in the market for replacement reserves. Panel b) shows an interesting change in the operation of the system. Historically, production has been high during the day and low at the night, cf. the orange curve. With the simulated prices for 2050, average production is lowest at daytime when solar radiation is high. The pumped storage is utilized more frequent in 2050-scenario because of short-term fluctuation in prices. When the pump is operated at full capacity, the producer becomes a net consumer.

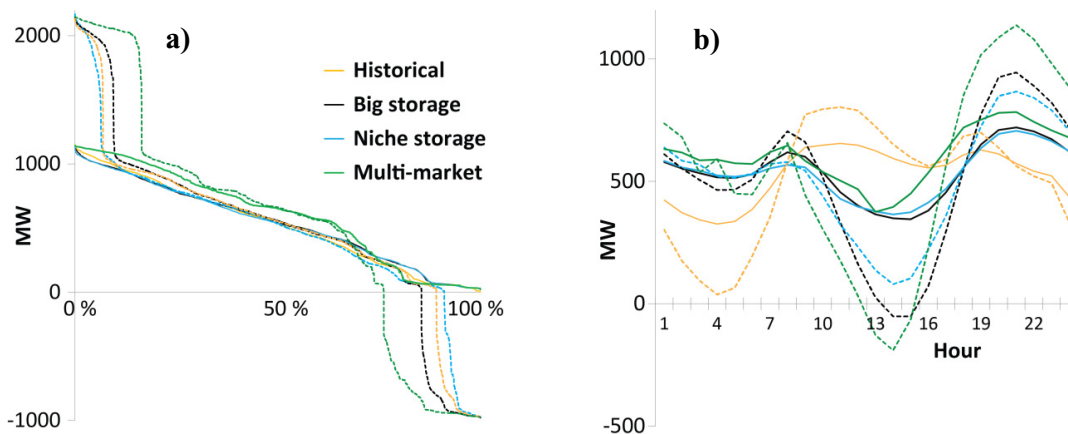


Fig. 3. (a) Duration curve of net production, and (b) Average daily production from the Otra river system. Dotted curves show operation after an investment in pumped storage.

Table 2 shows the average yearly income for the existing system before the new investment, and the average extra income as a consequence of the investment. In this section we focus on the left part of the table that shows the

profitability when electricity is supplied only for the day-ahead market. At historical prices, labelled Historical, in the table, the extra operating profits from the investment (9 M € per year) is less than the annualized investment cost (24 M € per year), leading to a negative profit for the investment project. In price scenario for the future, price levels and volatility is higher. As a consequence, the average yearly income from the existing system and extra operating profits from the investment is more than doubled. However, the investment is profitable at 5 % interest rate only for the Big Storage scenario.

Table 2. Profitability for Otra hydropower system with the different scenarios. Numbers are in M € per year.

	Day-ahead only scenario (Climate years 2007-2011)			German prices (Climate year 2008)	
	Historical	Niche Storage	Big Storage	DA only	Multi-market
Average yearly income	205	474	517	654	669
Additional operating profits from the investment	9	23	30	133	161
Investment cost *)	-24	-24	-24	-24	-24
Investment profits *)	-15	-2	5	109	137
Break even interest rate	-0,5 %	4,5 %	6,6 %	31,1 %	38,8%

*) With 5 % annual interest rate

5.3. Multi-market strategy

Participation in the market for replacement reserves is considered only for the Big Storage scenario, which is a scenario for full integration of European power markets. The corresponding strategy is discussed in Section 2, and simulation results for this case are labelled multi-market in Fig. 3 and Table 2. However, the results from this simulation cannot be directly compared with the scenarios for supply in the day-ahead market described in Section 5.2 because:

- Only one climate year is included for reserve prices, cf. Section 3.2. The expected future price as calculated by the model will then be the actual realization of prices, leading to perfect foresight in strategy calculation.
- In the European simulation, German day-ahead prices are not higher than Norwegian prices. However, day-ahead prices for Germany are somewhat higher and more volatile in the detailed study for Germany because additional markets are accounted for.
- The inflow to the considered river system was higher in climate year 2008 than on average for 2007-2011.

To create a reference value for the extra profits obtained when participating in the market for activation of replacement reserves, we therefore simulate the profits when supplying only for the day-ahead market for climate year 2008 and with German prices. In Table 2, the two columns at the right are for climate year 2008. The far right column show results when applying the multi-market strategy.

Average yearly income for the existing system increases by 15 M € per year if the producer supply replacement reserve energy. This is a moderate increase in relative terms (2.2 %). However, the supply of reserve energy has a larger impact on the profitability for the investment. The extra income generated by the investment increases by 28 M € per year (21.0 %). The main reason for this difference (2.2 % vs. 21%) is the following: total income is more affected average prices since a given annual inflow energy is at disposal, whereas the benefit of the pumped storage plant is mostly given by price volatility.

6. Concluding remarks

The traditional profile where hydropower generation is high during day and low at night can be changed in the future because of solar power. With pumped storage, hydropower producers can also become net consumers parts of the day. Simulated prices for 2050 are higher and more volatile than historical prices, and simulated prices for activation of reserve energy more volatile than day-ahead market prices. Whereas higher prices gives higher profits for the existing system, higher volatility leads to increased profits for an investment in pumped storage.

When supplying only for the day-ahead market, the investment is not profitable at historical prices, whereas the project is about in break-even for 2050 scenarios. However, substantial extra profits can be obtained from supply of

reserve energy. Our study therefore indicate that active participation in European market for balancing energy can be decisive for the profitability of pumped storage projects in Norway. Participation in markets for procurement of reserves could increase profits further, but this has not been analyzed.

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