Opportunity-cost-pricing of reserves for a simple hydropower system

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***Abstract*—This work investigates the cost of delivering different types of balancing reserves from a simple hydropower reservoir system. In addition to delivering energy, the fast ramping characteristics of hydropower units makes them suitable for delivery of various balancing products that are needed in order to maintain system security. The price at which these products are offered is determined by the opportunity costs in the day-ahead energy market. In a small case study, these opportunity costs are assessed by analyzing the changes from the optimal day-ahead production schedule for various types and volumes of reserve delivery commitments. We find that the requirement of delivering spinning reserves may significantly restrict the production schedule. This type of balancing service is thus found to be costly in our analysis. The special restriction of symmetric up and down regulation for primary reserves also makes this type of service more expensive as the solution space is even more restrained.**

I. Introduction

The European power market is in transition towards a low-carbon future. Binding targets exist for renewable power generation towards 2020 and ambitions reach even further. As a consequence, the need for balancing intermittent renewable energy is growing. New cables that are planned from Norway to the European continent may facilitate the utilization of Norwegian hydropower to supply a share of the needed balancing services. Hydropower is well suited for delivering balancing reserves due to low start-up costs and fast ramping capabilities.

The power system is planned to be in balance for the next operating day, but the system is continuously exposed to factors that may disturb this balance, such as deviations from forecasted generation from wind or solar, short-term changes in consumption or breakdowns of production facilities and lines. To be able to handle these unforeseen events, it is essential that there are sufficient balancing reserves in the system to restore and maintain the system frequency. In this work, we analyze the price of delivering such products from a simple hydropower reservoir system.

Generation companies offering balancing services can add the profits from selling reserves to the income from the day-ahead energy market. The question for the generation company is thus how much capacity to offer to the energy market and how much to offer to the balancing markets. The allocation decision will have an impact on the production schedule that is feasible in the day-ahead market and also on the income generated. It is therefore important to set the right price for the capacity offered as reserve. Any income lost in the day-ahead market due to changes in the optimal schedule must be recovered in the balancing markets in order for it to be a viable strategy for the generation company to offer such products.

This paper will take the view of a price-taking hydropower generation company that must allocate its capacity among the energy-only day-ahead market and markets for various types of balancing. The balancing products that are assessed here correspond to the current definitions set by the Norwegian system operator, Statnett, [1]. For calculations, we use the mathematical optimization model that is used by most large Nordic hydropower producers in their daily operations to find the optimal production schedule [2]. A small test case is used to illustrate our findings.

II. Methodology

The methodology for calculating the opportunity cost for offering capacity to the balancing markets is based on the framework described in [3]. It is also similar to [4] and [5] where also the formulation of a mathematical model akin to ours is presented.

We use the operational short-term production scheduling model as described in [2] and [3], where the objective is to maximize profits from power sold to the day-ahead market, subject to all physical and environmental constraints relevant for hydropower systems such as reservoir balances, start-up costs, head-dependencies and ramping restrictions. The model has a one-week horizon with hourly time resolution. The system state at the start of the week, forecasted values for inflows to the reservoirs and day-ahead prices as well as the resource costs of water in the form of water values are input to the model. In the optimization, the water values are compared to the forecasted day-head prices to find an optimal production schedule that maximizes the utilization of the available resources. Some of the physical elements of the hydropower system require nonlinear or state-dependent modelling, so in order to keep the formulation general and tractable even for large cascaded reservoir systems, successive linear programming (SLP) [2] is used. This means that non-linear relationships such as the discharge-to-power output of each turbine is described by a piecewise linear approximation and that state-dependencies are resolved by iterations that gradually refine the solution. The reader is referred to [2] and [3] for details, but we note that the SLP framework makes it possible to optimize the production schedules with a high level of detail in the physical description of the reservoir system. This means more accurate opportunity costs estimates.

To calculate the opportunity costs and hence the price at which to offer balancing services, Step 1 is to find the optimal production schedule and the profits when the generation company only participates in the day-ahead market. This will be the base case. Step 2 is then to add restrictions to the model stating that certain volumes of specific types of balancing products have to be to be delivered. This means that capacity must be withheld from the energy market to be able to cover the reserve obligations. With this restriction, a new optimal production schedule is found with resulting profits. As restrictions are added to the model, the new objective may be lower than the base case objective function value. The difference in objective function value calculated in Step 1 and Step 2 will thus be the cost of reserving capacity, and the generation company will seek to recover at least this cost from the balancing markets.

The above calculations are repeated for various kinds of balancing products as well as different volumes for each kind. We are interested in how the prices of each product relates to the changes from the optimal base case production schedule. In particular, we look at primary, secondary and tertiary reserves as defined by Statnett [1] and will sometimes use the common abbreviations from the Norwegian system in the rest of the paper. Both primary (Frequency Containment Reserves, FCR) and secondary (Automatic Frequency Restoration Reserves, FRR-A) reserves must be reserved from generators that are running, as they must be able to respond very quickly. The activation is done automatically, in contrast to tertiary reserves (Manual Frequency Restoration Reserves, FRR-M) which are activated manually and do not have to be spinning.

For each type of reserve, we look at different volumes to be delivered. It might require only a small change in the optimal schedule (and thus a small cost) to deliver 1 MW of balancing capacity, while large changes are necessary to deliver larger volumes. This is particularly important for primary reserves, as they are required to be symmetric for up and down regulation, meaning that the same volume has to be available for up and down ramping at each instant. This is a challenge when for instance the unit is running at maximum (minimum) capacity with no possibility for up (down) regulation, but large possibilities for down (up) regulation. Fig. 1 shows the capacity limits for different types of reserves for the units used in the case study of the next section.

III. Results and Discussion

We analyze delivery of balancing services from a one-reservoir system with two identical generator units, each with a capacity between 30 and 45 MW. Best-point efficiency is achieved around 40 MW. The data for the case study is partly fabricated, but the physical description corresponds to a real reservoir system located in Norway. Prices are taken as the historical realized prices for the week in question, while water values and scenarios for inflow are generated by the authors. The results we obtain will hence not give results that are realistic in the sense that they can be compared with the actual prices in the balancing markets for the given week. However, the results do illustrate how the cost of delivering balancing services depends on the changes in the optimal day-ahead energy-only production schedule.

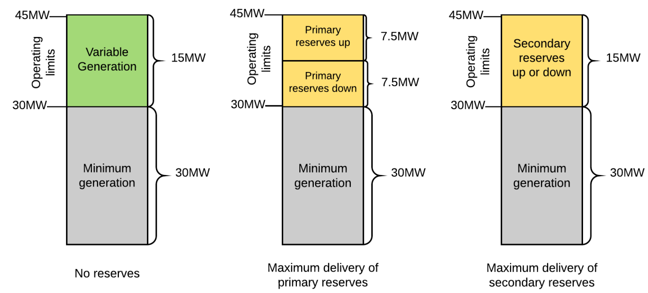


Fig. 1: Capacity limits for primary and secondary reserves for a unit with operating range between 30 and 45 MW.

TABLE I: Initial conditions for the normal, dry and wet situation.

	Normal	Dry	Wet
Initial Reservoir level (%)	70	50	100
Inflow (% of maximum discharge)	27	18	107

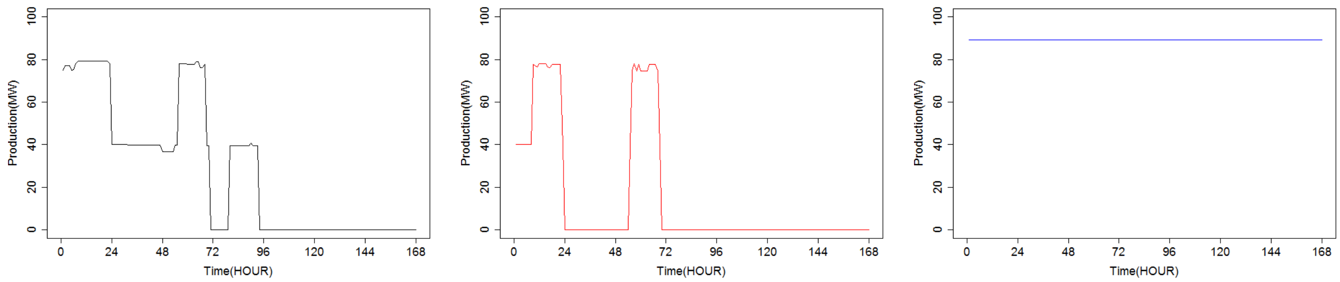
Three different scenarios for the situation in the reservoir system are analyzed, corresponding to normal, dry and wet conditions. These scenarios are determined by the initial reservoir level and the volume of inflow, as seen from Table I. The wet situation may seem extreme, but the high values are chosen to illustrate operation of a run-of-river system with no reservoir storage which nessesitates production of all incoming water.

A. *The optimal energy-only production schedule*

The optimization will find the balance between water produced within the week and water left in the reservoirs for production at a later time. Basically, it is profitable to generate when the price is higher than the water value. For the week under study, prices are higher than average on Day 1 and 3. The optimal base case production plan for the normal, dry and wet scenario can be seen in Fig. 2. In the wet scenario, there is maximum production in all hours to minimize the inevitable spill. For the normal and dry situation, it is worth noting that the optimal production level is around best-point operation, which is less than maximum capacity. This means that some capacity is avilable for up-regulation during these hours.

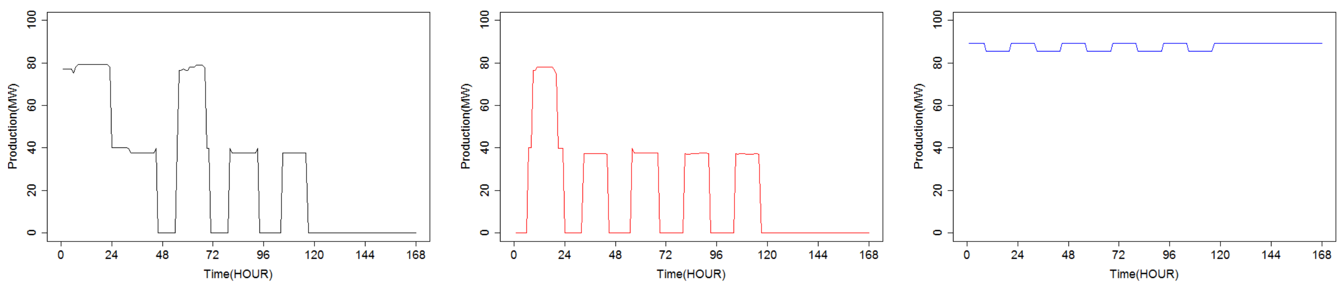
B. *The primary reserves market, FCR*

We consider the weekly market for primary reserve, where capacity can be allocated as reserves for weekdays or the



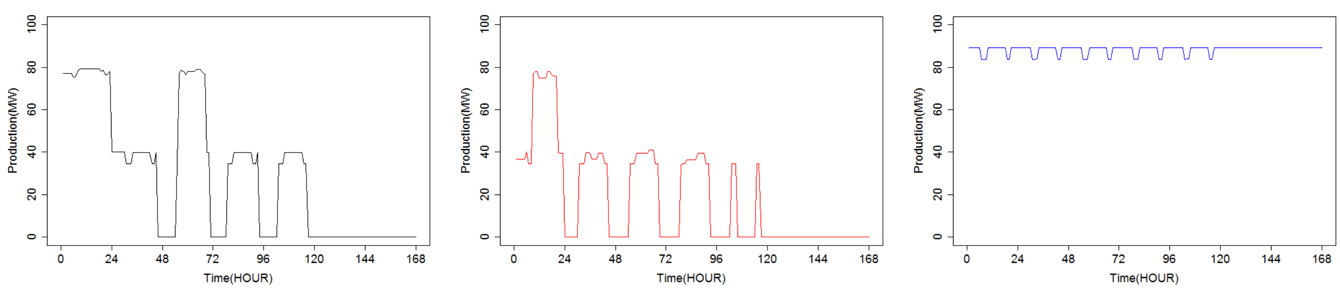
(a) Normal (b) Dry (c) Wet

Fig. 2: The optimal one-week production schedules with no reserve obligations for the reservoir system analyzed in the case study for the normal, dry and wet situation.



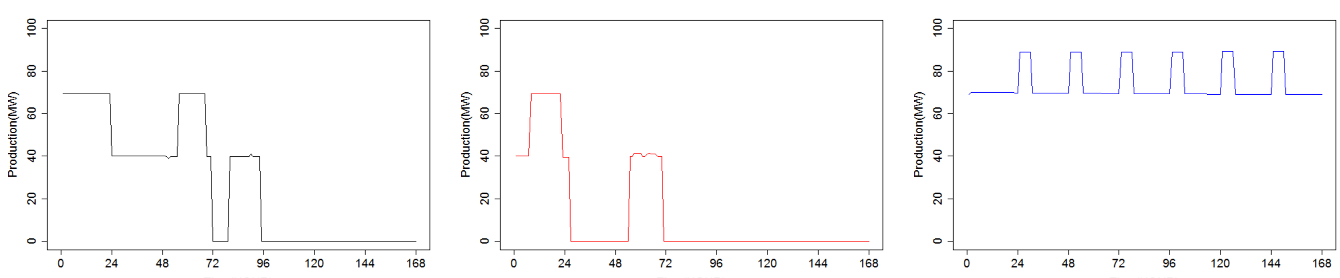
(a) Normal (b) Dry (c) Wet

Fig. 3: The optimal production schedules when 7 MW of primary reserve should be delivered between 08.00-20.00 Monday-Friday.



(a) Normal (b) Dry (c) Wet

Fig. 4: The optimal production schedules when 10 MW of upwards secondary reserve should be delivered between 06.00-09.00 and 18.00-20.00 Monday-Friday.



(a) Normal (b) Dry (c) Wet

Fig. 5: The optimal production schedules when 20 MW of upwards tertiary reserve should be delivered between 06.00-00.00 every day.

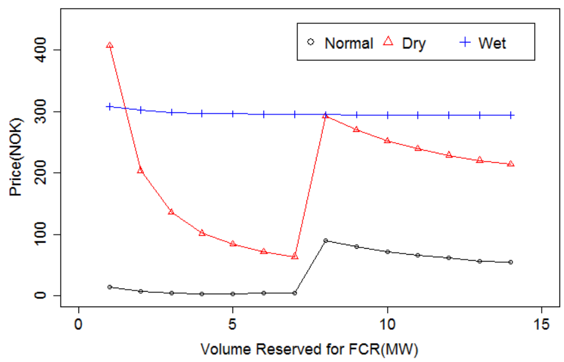


Fig. 6: Cost per MW of delivering primary reserve, FCR.

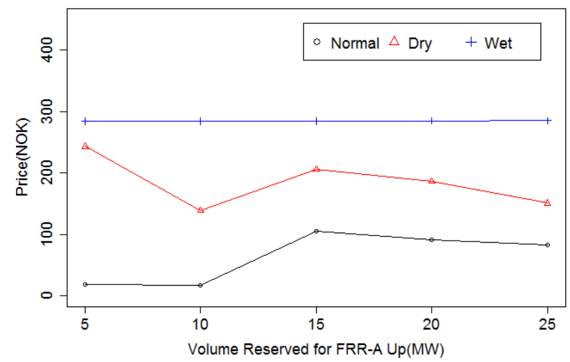


Fig. 7: The cost per MW of delivering upwards secondary reserve, FRR-A Up.

weekend, for hours during the night, day or evening. We consider delivery of FCR for Monday-Friday between 08.00 and 20.00. Because capacity has to be available for symmetric up and down regulation, maximum capacity reserved for FCR is 15 MW for the system. Fig. 3 shows the re-optimized production schedule when 7 MW should be delivered.

When participating in the FCR market, the generators have to be spinning for the relevant hours. This leads to a requirement of running the generators in hours that may not be optimal from the base-case production plan. Keeping a generator running for several hours with a low spot price compared to the water value result in losses. However, if the extra generator is started, it will be less costly to deliver the maximum reserve capacity from the generator, as the start-up cost then could be divided by a larger amount of capacity. Therefore, the cost of delivering primary reserves per MW is decreasing until a new generator has to be started. This trend can be seen in Fig. 6, where the cost per MW of delivering different volumes of FCR is plotted. For the wet scenario, both generators are always running and do not have to be started in order to deliver the committments. However, as both of the generators are operating at maximum, no excess capacity is available for up regulation and the production has to be lowered in the hours where FCR is contracted, which leads to a cost.

C. The secondary reserves market, FRR-A

Secondary reserves are sold in a weekly market where the time intervals may vary from week to week. For the given week, the defined time interval for the FRR-A market is Monday - Friday 06.00 to 09.00 and 18.00 to 20.00. Since the direction of the regulation is either up or down, maximum capacity reserved for secondary reserves is 30 MW. The market rules state that the minimum amount of reserved capacity should be 5 MW, and the amount has to be divisible by 5.

As for the primary reserves, FRR-A has to be available from spinning units. If the units are running at best-point in the original production schedule, some capacity is available as reserves, and the cost of delivering the available volume is

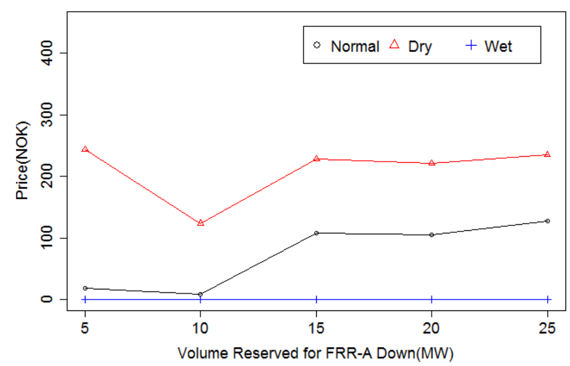


Fig. 8: The cost per MW of delivering downwards secondary reserve, FRR-A Down.

low. However, the generators are sometime started only to be spinning for the given hours during the morning and evening, as seen for the dry and wet scenario in Fig. 4.

The cost per MW of delivering upwards and downwards FRR-A is plotted in Figs. 7 and 8, respectively. In the wet scenario, delivery of up regulation is expensive, as a decreased production yields more spill. Downwards regulation, on the other hand, is offered at almost zero cost.

D. The tertiary reserves market, FRR-M

For tertiary reserves, the time interval for the weekly market is 06.00 to 00.00 every day. We only look at upwards reserves. A re-optimized schedule is shown in Fig. 5. In total, 60 MW can be reserved as FRR-M from the system.

Because tertiary reserves do not have to be spinning, the generating units can be started if activation is needed. Arguably, the tertiary reserve requirement is only a restriction on maximum production. For the normal and dry scenario, the produced power in the original production schedule never exceeds 80 MW and about 10 MW is thus available for up regulation at a low price. If more capacity is reserved, the restriction on maximum production becomes binding, lowering

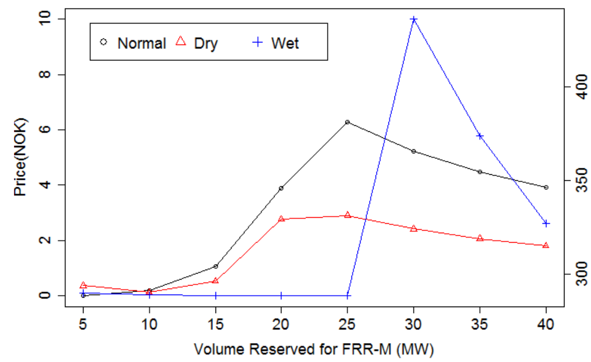


Fig. 9: The cost per MW of delivering tertiary reserve, FRR-M. The normal and dry scenario have y-values on the left-hand side, while the wet scenario, with much higher prices, use the y-values on the right-hand side.

the peak production when the spot price is at its highest. In order to deliver more than 25 MW of reserve, one of the generators has to be stopped, but this cost can be distributed over increasing volumes for larger reserve commitments. Furthermore, the cost of delivering reserves is generally higher for the normal scenario than for the dry scenario, as seen in Fig. 9. This is because the generation is lower in the dry scenario, and more capacity is already available for up regulation.

For the wet scenario, both the generators are operating at maximum capacity in order to minimize spillage. When capacity is reserved for up regulation, production has to be decreased, resulting in more water being spilled. The opportunity cost of decreased production is the average spot price over the delivery hours for tertiary reserves. This is the case up to the point where one of the generators has to be stopped, after which the start-up cost must also be added.

The main difference between capacity reserved in the FRR-M market and capacity reserved in the previous markets is that the reserves now does not have to be spinning. This affects the opportunity cost, since the generators do not have to be producing energy in hours with a lower spot price than what is optimal in order to deliver capacity. The main cost of delivering capacity in the FRR-M market is the cost of having a restriction on maximum capacity. This restriction also applies for the other types of reserves, but the cost of the spinning restriction is much higher. Hence, the costs of delivering capacity in the FRR-M market are generally lower than delivering capacity in the other types of reserves.

IV. Conclusion

A method for evaluating the cost of delivering different kinds of balancing products for a hydropower system is presented and used to analyze the cost for a small test system. The method is applicable for larger systems as well. The cost of delivering balancing reserve is determined by the opportunity cost of withholding capacity from the day-ahead market where energy is traded. We find that for an individual producer, this opportunity cost is closely related to the restrictions imposed on the optimal day-head energy schedule by offering other products. If large changes are necessary to be able to deliver the requirements, and if these changes are costly, the balancing product will also be costly and should be offered at a high price in order for the generation company to be able to recover its losses from the day-ahead market in the balancing markets.

We find that the requirement of delivering spinning reserves may significantly alter the production schedule. This type of balancing service is thus found to be costly in our analysis. The special restriction of symmetric up and down regulation for primary reserves also makes this type of service more expensive as the solution space is even more restrained. On the other hand, our results also illustrate that in normal operation around best-point production, all types of reserves (primary, secondary and tertiary) can be delivered quite cheaply from hydropower units, as the calculated price is comparable to the day-ahead energy price.

Although the analysis is presented only for a small test case, the cost trends in delivering the different types of reserves in the weekly markets are mirrored well. If the reserve requirements could be distributed over a larger portfolio of hydropower units, we expect the costs to be lower as there would be more flexibility available in the system to allocate the commitments to the least-cost units. In conclusion, the results of this analysis are relevant when planning the power production in both the day-ahead market as well as in the balancing markets. With a growing demand for balancing, the benefits of participating in the latter markets may have a great potential for hydropower producers.

Acknowledgment

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