Water Behind Capacity

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Abstract

A future power system based on intermittent renewables will depend on system services being supplied by conventional energy sources. As interconnections grow stronger, Nordic hydropower may deliver balancing reserves to the rest of the European power system. However, even if instant capacity is available from hydropower units, available energy is not always guaranteed as the consequences of real-time activation are often not analyzed for the entire multi-reservoir system. Water behind capacity is a term that describes the specific challenge of hydropower producers to comply with all technical, hydrological and environmental constraints in the river chain in the case of activation. In this work we analyze the effect of activation using a combined optimization-simulation approach. We illustrate by simple case study examples that the amount of reserves that can actually be delivered is limited, even though more capacity can easily be reserved from the hydropower units.

Key words: Hydropower, Renewable Energy, Reserve, System services, YPP

1 Introduction

With the 20-20-20 energy and climate targets set by the EU, more intermittent renewable energy is expected to enter the European power system in the near future. A power system based on intermittent renewables will depend on system services being supplied by conventional energy sources. In addition, climate change may contribute to more extreme weather conditions, increasing the frequency of transmission and generation outages. Hence, power supply may become less reliable and the need for regulating reserve is growing. European energy producers are faced with a growing market for ancillary services in parallel to highly liquid energy markets.

A well suited, renewable source for balancing reserves is hydropower. As interconnections grow stronger, Nordic hydropower may deliver regulation reserves to the rest of the European power system. Hydropower stands out for its fast response and flexible operation. Water is stored in reservoirs and can be produced to energy whenever needed. Units can quickly respond to requests of activation, as output can be changed from the minimum to maximum level in just a few seconds.

However, even if instant *capacity* is available from hydropower units, available *energy* is not always guaranteed as the consequences of activation are often not analyzed for the entire multi-reservoir system. *Water behind capacity* is a term that describes a specic challenge for hydropower producers who provide reserves. Hydropower is an *energy-constrained* technology and will not be able to deliver capacity unless there is enough water to back up any activation called upon in real time. Even if enough water is available, there may be other technical, hydrological or environmental constraints in the river chain that limit the amount of reserves that can be delivered. Topology-related restrictions may vary greatly between hydropower systems. In some systems, there may be minimum pressure constraints that must be met for both the scheduled production and any eventual activated reserve. In other systems, there can be minimum or maximum flow constraints, reservoir limits or maximum ramping rates. Water behind capacity is used as a collective term for all infeasibilities that may arise from activating reserves in real-time.

The volumes offered as reserve by many hydro producers today are small enough to be handled without having to utilize all available flexibility in the river chain. Given the expansion and integration of reserve deliveries across Europe, volumes are likely to increase. To ensure that all restrictions are met in real time, the consequences of prolonged activation have to be analyzed for all parts of the hydropower system, not just as added/subtracted MWs on the generating units. The activation will have to be converted to flow through penstocks and tunnels, pressure difference in gauges, creek intakes and junctions and change in pressure height in reservoirs. Environmental constraints such as ramping or minimum and maximum flow will also gain importance with increasing reserve delivery.

In this paper, we analyze the consequences of activation for a two-reservoir hydropower system by using a combined optimization-simulation approach to determine the operation of the system for various amounts of activation. Our results illustrate that the costs and volumes of reserves that can be delivered are strongly related to the amount of water available in the reservoirs.

In Section 2, we give some background on literature that cover scheduling of hydropower in markets for energy and capacity. In Section 3, we present how we use optimization and simulation to analyze the consequences of activation. Section 4 shows results a case study. Some conclusions are given in Section 5.

2 Background

Water behind capacity has so far been given little attention in the literature on hydropower scheduling. A first approach is presented in (Chazarra et al. 2016), which presents a stochastic optimization model that finds an optimal schedule that simultaneously maximizes the expected profit in both the energy and regulation reserve market. The main contribution is that the obtained solution protects a multi-reservoir system against the risk of water unavailability due to uncertainty in real-time use of reserves. We aim to use a combined optimization-simulation approach to study the same issue.

Our modelling is based on (Belsnes and Fosso 2004), which is the basis of the software that is used for short-term scheduling in the Nordic hydropower industry. Other approaches to short-term scheduling can be found in (Borghetti et al. 2008; García-González and Alonso-Castro 2001; Pérez-Díaz, Wilhelmi, and Sánchez-Fernández 2010; Conejo et al. 2002; Diaz et al. 2011; Catalao et al. 2009). These methods take prices and inflows as deterministic and do not consider co-optimization of sales of energy and capacity. The focus is on the level of detail in the representation of the hydropower system rather than the market. The models in (DeLadurantaye, Gendreau, and Potvin 2007; Fleten and Krisoffersen 2007) consider sales of energy when electricity prices are stochastic, while (Tsai et al. 2009; Deng, Shen, and Sun 2006) co-optimize sales in the day-ahead energy market and markets for reserves. For detailed system descriptions and/or large multi-reservoir systems, finding the optimal production schedules for combined sales of energy and capacity leads to very complex problems. Trade-offs must thus be done between the level of detail in the representation of the physical system, the market, or both, and calculation time. Sacrificing too much detail will make the model unable to verify that constraints are not exceeded when reserves are activated, and too long calculation times will not give the producers the answers they need in time.

In this work, we do not aim to extend the model in (Belsnes and Fosso 2004) to optimize combined sales of energy and capacity for a detailed description of the hydropower river chain. Rather, we use the existing modelling framework to analyze the consequences of *not* considering activation when offering reserve capacity. To do this we use a simulation model that calculates the operation of hydropower river chains given a fixed production schedule. The simulation works with the same detailed description as used in the optimization, but calculates the water flows in all parts of the system in time steps of 20s. In contrast, the time steps in the optimization is 1 hour.

As stated earlier, Nordic hydropower may potentially contribute with a large share of the system regulation for the European power system. For the case study in this paper, however, we use the definitions of reserves as currently set by the Norwegian TSO, and we focus on regulation reserves in the rest of this paper. Regulation reserves are activated if the fast-response spinning reserves are depleted, and may be kept online for a longer period of time, sometimes even a few hours. The necessary change in power output could thus be present for a long enough time to signicantly change the water flow from the original schedule. Hence, delivering large amounts reserve from hydro systems with limited flexibility could lead to water unavailability in periods when the power system needs more regulation. In the case study in Section 4, we consider the Norwegian regulating reserves option market (RKOM), where capacity is committed to regulation reserve for the next week. This market helps supply the TSO with sufficient capacity in the regulation reserve market and is at the time being mostly active for up regulation during the high load winter season.

If, during the week, more capacity has been reserved than can be delivered, actions has to be taken in order to hold the reserve commitments. The production schedule in the energy market is not fixed for the week – it can be changed daily. Therefore, if there is a chance of water unavailability due to activation early in the week, less energy chould be scheduled to the energy market for the rest of the week in order to save water for any eventual activation. However, such changes may be suboptimal for producers as it may force them to generate less energy when prices are high. Hence, too high commitments in the RKOM market may result in a lower total income. For these reasons, it is of much interest for hydropower producers to verify the amounts of reserves that can actually be delivered when making offers in the RKOM market at the start of the week.

3 Method

We look at the consequences of reserve activation for a multi-reservoir hydropower system by carrying out a 3-step analysis that combines optimization and simulation. First, we assume a distribution of the number of hours with activation for the coming week using historical data. Second, we find the maximum amount of reserve that can be activated without breaking any constraints in the river chain. Finally, we find the cost of delivering reserves. Each of these steps are described in detail in following three subsections. The analysis has been carried out from the point of view of a price-taking hydropower producer.

3.1 Finding the expected number of hours with activation

The first step is to find the expected number of hours when activation will be needed from the given hydro system. Historical data for the Nordic power system is used to find the mean and standard deviation of the number of hours when the total power system is in unbalance and needs regulation. A normal distribution is then assumed to find the probability of a given number of hours with unbalance during a week. The amount of unbalance is not normally distributed in reality, but this distribution is used for simplicity. Forecasting the amount of activation needed is difficult, as events that cause unbalances are per definition unpredictable events.

Furthermore, it is unlikely that a certain hydro system is activated every time the power system is in unbalance. This is because there usually is more reserved capacity than what is needed, and capacity is activated in merit order by the TSO. Different rates, n, of how often capacity from the given hydro system is activated when the power system is in unbalance are used. The rate of activation is dependent on the price of the offered reserves, which is determined by the hydropower producers based on assessments of the cost of delivery. The rate of activation also depends on transmission capacity, as capacity is not activated if there is a bottleneck in the grid between the hydro system and the area where reserves are needed. True rates of activation can be estimated based on historical data on how often specic plants are activated, which are private information for the hydropower companies. We therefore use illustrative rates of activation set at 25 and 50%. These values are probably too high to be realistic, but limitations regarding water behind capacity are illustrated more clearly using higher rates. In addition, both the total amount of reserves and the share of reserves from hydropower is expected to increase. The analysis would be carried out in the same way using the true rates of activation. For each rate of activation, the producer will set a risk level, r, for the maximum number of hours when regulation is needed. Operations should be planned so that all levels of activation within the risk level can be delivered. The distributions for n=50% and n=25% are presented in Fig. 1, with the two risk levels of 1 % and 5% marked as vertical lines.

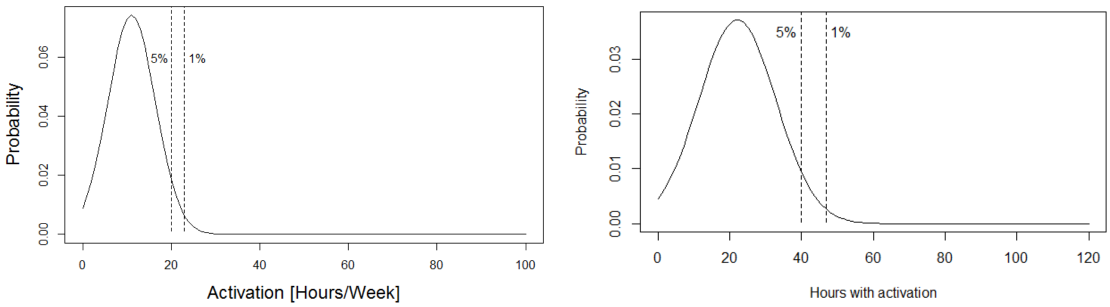


Figure 1: Distributions for number of hours in a week when reserved capacity is called upon from the given hydropower system, for $n = 25\%$ (left) and $n = 50\%$ (right). For instance, looking at the graph to the right, there is a 5% chance that activation will be required for more than 40 hours if the river chain is activated half of the time the power system needs regulation.

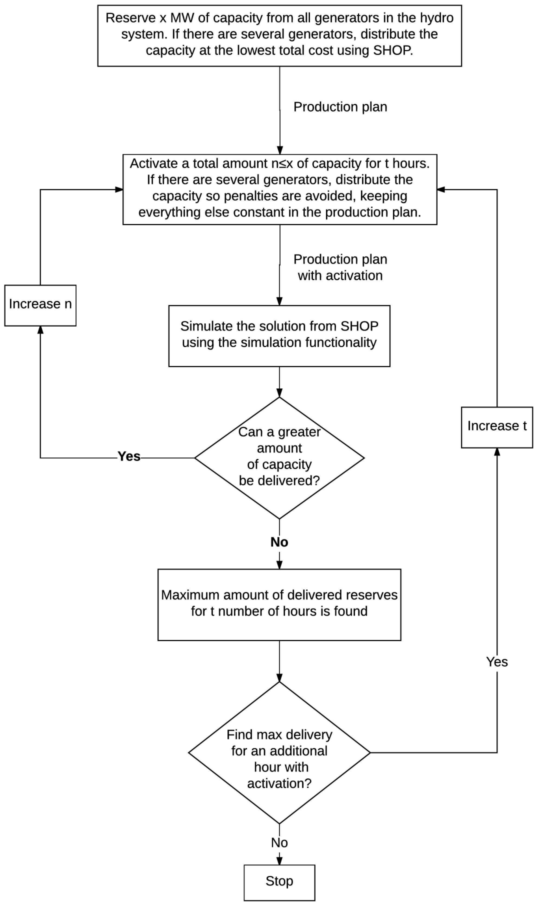
3.2 Finding the maximum amount of reserves that can be delivered

The next step is to find the maximum volume of reserves that can be delivered for a given number of hours with activation. The procedure is illustrated in Fig. 2a. In the optimization model (Belsnes and Fosso 2004), it is possible to allocate a pre-specified volume to reserves, and then optimize the remaining volume to be sold in the energy market. The first step in finding the maximum amount of reserve that can be delivered, is to dedicate a certain volume to capacity by withholding in from the energy scheduling. Capacity is reserved from the different generating units at lowest total costs or at a fixed rate set by the operator. This results in an original production schedule that does not consider activation.

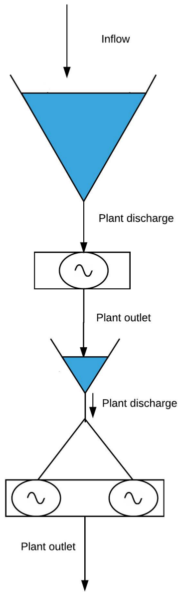
We then start by activating a small amount of capacity by adding a load to the original production schedule in the hours selected for activation. A new optimization is then performed, where the activated capacity is optimally distributed over the generating units that have reserved capacity. This results in a production schedule with activation, which is verified in the simulator. As stated earlier, the simulation checks that all restrictions are adhered to even with a much finer time resolution. If no restrictions are violated, it may be possible to deliver larger volumes of reserves, so we go back to the first step and increase the amount of capacity withheld from the energy market. When the capacity is increased up to the point where water availability or any other constraints are violated, the previous amount of capacity which did not violate any constraints is the maximum amount that can be delivered for the given number of hours.

The process above is repeated for increasing number of hours with activation in order to obtain a relation between the maximum volume that can be delivered and the number of hours with activation. As we are investigating the effect of water behind capacity, the above process is repeated for different amounts of water held back from the energy scheduling. That is, in addition to reserving capacity, we also set limits on how much water must remain in the reservoir in order to back up any eventual activation. As will be shown in the case study in Section 4, holding back water enables the producer to deliver larger volumes of reserve, but also limit the possibilities in the energy market which leads to higher cost on reserve.

In the case study, only one pattern of hours with activation is analyzed. In reality,



(a) Flowchart



(b) Topology

Figure 2: (a) Flow chart of the method to find the maximum amount of reserves that can be delivered for given periods of time. SHOP is the name of the specialized optimization software used for hydropower production scheduling. (b) Sketch of the topology of the river chain analyzed in the case study.

it is not possible to predict when an unbalance will occur, and any combination of hours is possible. For each combination, the amount of reserves that can be delivered may be different, as the same volume of activation may lead to water unavailability at one point in time and not in others. It could be possible to find the worst possible pattern of activation and then verify the amount of delivery for this pattern, but this has not been done in this work. Also, the production schedule for the energy market is not updated daily, which takes away any opportunity to recover from infeasibilities due to water unavailability observed during the week.

3.3 Finding the cost of delivering reserves

Given the maximum amount of capacity that can be delivered for a given number of hours, the costs of delivering various amounts of capacity up to this level has been found. This is also repeated for different levels of water held back.

The cost of offering reserves corresponds to the cost of lost opportunities in the energy market, as there is a trade-off between selling the water in the energy market and withholding it as reserve. To calculate this cost, the optimization model is run without allocating any capacity to reserves. This creates a base case for the total profits that can be obtained from the energy market only. To assess the loss in profits, the optimization model is run with increasing amounts of capacity withheld for reserves. This corresponds to the first step in the flow chart in Fig. 2a. The difference in profit from the base case will be the opportunity cost that the producer would like to make up for by offering reserves. To nd the cost of delivering reserves per hour per MW, the total opportunity cost is divided by the number of hours the capacity is reserved for, as well as the amount of capacity which can be delivered.

4 Case study

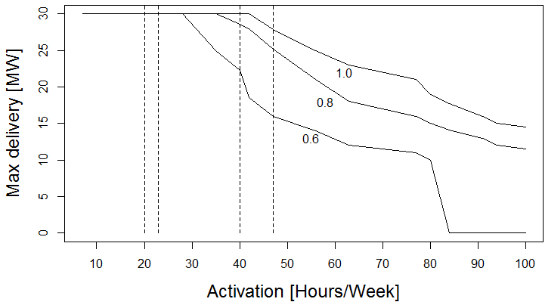
The case study is based on part of a real multi-reservoir hydropower system, with only small modications made in order to obtain clear results. The topology is pictured in Fig. 2b. Data for the reservoir topology, specifications of the generating units as well as prices and inflow are provided by the company that owns and operates the system. The planning period is one week, and we use data for the winter season where energy prices are generally high and inflow is low. The case study only consider water unavailability, but other types of restrictions such as ramping and minimum pressure height might be just as important for other topologies.

The main motive for studying this system is to investigate the possibility of water unavailability in constrained, cascaded systems. The system consists of two reservoirs and two plants in series. The upstream reservoir is an aggregation of several reservoirs and thus have a very large storage capacity. The upstream plant has a single 40 MW generating unit. The downstream reservoir is very small, and can be filled with about a day's maximum production from the upstream plant. It can also be emptied with about 14 hours of maximum production from the downstream plant, which has two generating units of about 75 MW each. The small reservoir is the cause of limited reserve delivery, as activation upstream may lead to spillage and activation downstream may lead to water unavailability. To illustrate, we look at activation from only the downstream, only the upstream and then both plants in the following three subsections.

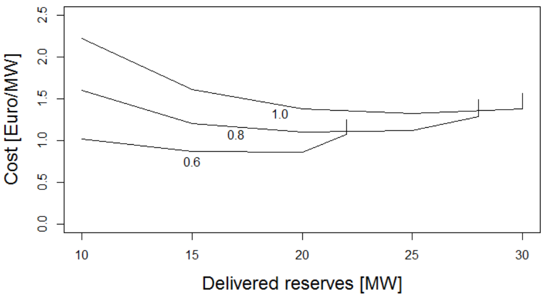
4.1 Activation downstream

As the downstream reservoir is so small, not only capacity but also water has to be withheld from the energy market in order to be able to activate the reserved capacity from the downstream plant. Thus, when going through the three steps presented in Section 3, the water level in the downstream reservoir is required to never to fall below 0.6, 0.8 and 1.0 MM3. The results for maximum reserve delivery are presented in Fig. 3a. By holding back water, it is possible to deliver any combination of volume and duration of reserves that are below the curves. All obligations can be delivered for the lowest activation rate of 25%, but for the higher rate of 50%, the company fails to meet the requirement at the highest risk level. Beyond these levels, large amounts of water needs to be held back in order to cover high volume commitments for an extended period of time.

The cost per MW of delivering reserves when the rate of activation is 50% is presented in Fig. 3b. The flexibility in the energy market is reduced as more water is withheld. Consequently, the profits in the energy market are reduced, and the total opportunity costs of delivering reserves increase. This cost is however divided



(a) Amounts of reserve



(b) Costs of reserve

Figure 3: (a) Results for the maximum amount of reserve that can be delivered from the downstream plant by holding back water from the energy scheduling. If for instance 0.6 MM3 of water is held back, all reserve commitments below the curve can be delivered. As more water is held back, more reserves can be delivered. The number of hours corresponding to risk levels at 1% and 5% when the rate of activation is 25% and 50% are drawn as dotted vertical lines. (b) The costs of delivering reserves from the downstream plant for different amounts of water held back.

by the amount of delivered reserves in order to find the cost per MW. Therefore, the cost per MW is decreasing when more reserves are delivered for the same amount of water held back. This is the case up to the point where more reserved capacity does not contribute to a higher amount of delivered reserves due to water unavailability. At this point, reserving more capacity leads to higher total opportunity costs, but as the amount of delivered reserves remains the same, the cost per MW increases. This results in the vertical sections in the graphs in Fig. 3b.

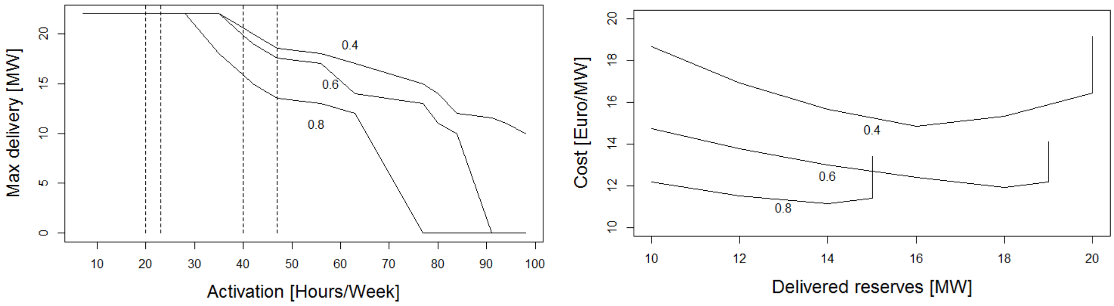
4.2 Activation upstream

When reserving and activating reserves from the upstream plant, the amount of water which is stored in the small, downstream reservoir has to be limited in order to avoid spillage if the reserves are activated. This is because the extra water used for activation is accumulated in the downstream reservoir. Since the energy production schedule at the downstream plant is already set when activating reserves upstream, it is not possible to use the extra water. Even though it is possible to deliver reserves that cause spillage, this is unwanted as loss of water equals loss of revenue. Therefore, it is required that the water level downstream never exceeds 0.8, 0.6 and 0.4 MM3 in the energy scheduling, resulting in limited flexibility. These results for the maximum amount of reserves that can be delivered are presented in Fig. 4a.

The cost of delivering reserves when the rate of activation is 50%, is plotted in Fig. 4b. When delivering reserves from upstream, the downstream reservoir is kept low in order to be able to deliver more reserves. Consequently, the total opportunity costs are increasing as less water is stored in the reservoir.

4.3 Activation from total system

Based on the costs of delivering reserves from the two plants separately, it is clear that the costs are larger when the reserves are allocated to the upstream rather than the downstream plant. When capacity is free to be allocated to both plants



(a) Amounts of reserve

(b) Costs of reserve

Figure 4: (a) Results for the maximum amount of reserve that can be delivered from the upstream plant by using more water in the energy scheduling. If for instance 0.8 MM3 is the maximum allowed reservoir level in the energy scheduling, all reserve commitments below the curve can be delivered. Using more water for energy makes room in the reservoir for activating larger volumes of reserve. (b) The costs of delivering reserves from the upstream plant. The costs are much higher here than when reserves are allocated to the downstream plant, see Fig. 3b .

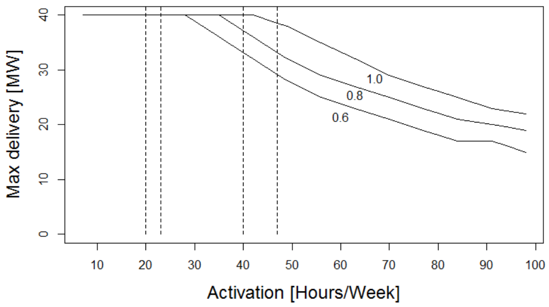
in a cost-minimizing manner, most of the capacity will therefore be reserved from the downstream plant. The downstream plant also has a larger generation capacity. Thus, even when both plants can deliver capacity, there is still a chance of water unavailability in the small reservoir due to activation downstream. Therefore, different amounts of water have been withheld in the downstream reservoir similarly to the case when reserves are delivered from the downstream plant only. The results for maximum reserve delivery are presented in Fig. 5a.

The results show that a much larger amount of reserves can be delivered from the hydro system when both plants deliver reserves compared to delivering reserves from downstream only for the same volume of water withheld. This is due to the fact than when both plants contribute to reserves, the extra water required for activation can be taken from upstream/downstream balancing out the risk of water unavailability/spillage at the small downstream reservoir which is present when reserves are only delivered from one of the plants. Since the generating capacity is larger and reserves are cheaper at the lower plant, a certain minimum reservoir level is still required.

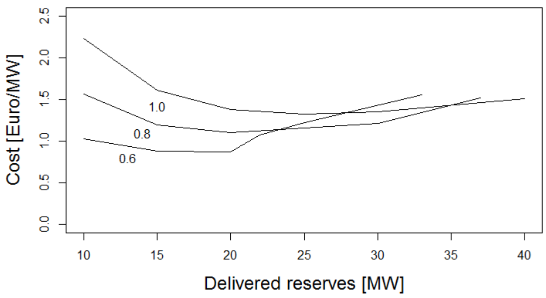
The costs of delivering reserves from the total system when the rate of activation of 50% are given in Fig. 5b. As reserves are delivered at lowest cost from the downstream plant for low amounts of reserves, the cost per MW of delivering reserves from both plants is very similar to the costs of delivering reserves from downstream only. All reserves are delivered from the downstream plant until its maximum amount of delivery is reached. For larger volumes, delivery has to be made from upstream as well. This leads to an increasing costs per MW.

5 Conclusions

In a future power system where power production is based on intermittent renewable energy sources, the need for regulating reserves will increase. Hydropower is well suited to deliver such services due to fast ramping capabilities. However, as hydropower is an energy constrained technology, the amount of reserved capacity that



(a) Amounts of reserve



(b) Costs of reserve

Figure 5: (a) Results for the maximum amount of reserve that can be delivered from the system by holding back water from the energy scheduling. If for instance 0.6 MM3 of water is held back, all reserve commitments below the curve can be delivered. As more water is held back, more reserves can be delivered, and deliveries from the total system is larger than from each plant separately. (b) The costs of delivering reserves from the total system .

can be delivered in real-time depends on the amount of water and the flexibility of the hydropower system. Water behind capacity describes the specific challenge for hydropower producers to be able to deliver reserve commitments in real time without violating any technical, physical and environmental constraints in the hydropower system. The introduction of new ancillary service markets and the important role of hydropower in these markets creates new challenges of how to participate in these markets in hydrological and economical sound manner.

We have illustrated by simple examples that the amount of reserves which can actually be delivered are limited, even though the system easily can withhold more capacity. This is due to water unavailability if the reserved capacity is activated for a prolonged period of time. Hence, the water level in the reservoirs from which the capacity is reserved should be constrained in the energy production schedule in order to be able to deliver reserves. However, the costs of delivering reserves are increased when the water levels are constrained. Therefore, it is not protable to constrain these levels more than necessary in order to be able to deliver a given amount of reserves. It will thus be a trade-off between the profits obtained in the energy and reserves market.

Other constraints than water availability might be more relevant in the real world, and this will depend on local technical, hydrological or environmental constraints. When scheduling for the energy market, the river chain's flexibility is often maximally utilized. Any eventual activation might have severe consequences in tightly constrained systems. The challenge when selling both energy and reserves is to find the balance between the profits obtained in the energy market and the need for a flexible schedule in the case of activation.

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