BIDDING IN THE SECONDARY RESERVE MARKET FROM A HYDROPOWER PERSPECTIVE

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Abstract – The paper addresses one of the challenges of short-term hydropower scheduling in a liberalized power system; bidding in the real time market for secondary reserve.

All over the world, deregulation of the power industry is implemented. Different schemes may be used from case to case but basically the fundamental challenge remains the same. Generation must equal consumption in order to maintain frequency and quality of the delivered electric energy. If generation and consumption is different, the need for regulation arises and typically this is done in a balancing market also called the real time market.

The paper proposes a method for decision aid to bidding in the real time market for owners of hydropower capacity in areas with deregulated electricity markets. Based on the economic dispatch of the units together with expected future operation cost, an estimate of the cost associated with regulation can be calculated. The actual cost of regulating is the lower limit on bids when participating in the real time market. The paper shows how this cost information may be organized to form a bidding table in the real time market, and discusses the practical implications of the approach.

Keywords: Real time market, short-term generation scheduling, unit commitment, deregulation, regulation costs, ancillary services.

1 INTRODUCTION

This chapter gives an introduction to the challenge addressed in the paper. The chapter tries to establish a bigger picture in order to set the task of real time bidding for hydropower generators into context. First the general task of planning and utilize hydropower is addressed from a Scandinavian point of view. Then the physical markets are described and in the end of the chapter the interaction between the market and the short-term generation scheduling is established.

1.1 Generation planning

In systems where some of the reservoirs have significant storage capacity, the use of the hydro power resources short-term will be coupled with the long-term strategic decisions. Hydropower generators also operate in systems with substantial thermal power generation or in systems interconnected to neighbouring thermal dominated systems. As a result the scheduling problem therefore has to be solved as a mixed hydro-thermal planning problem. Thus, the planning problem is a very complex process.

It is not feasible to have the short-term decisions within the same model as the long-term decisions, because modelling of uncertainty is important in the long-term perspective, and details are important in the short-term perspective. Commonly the problem is decomposed into a long term, medium term and a short-term problem, each being solved by dedicated models and solution techniques, as shown in Fig. 1. In this planning hierarchy the long/mid-term models provide boundary conditions for the short-term models.

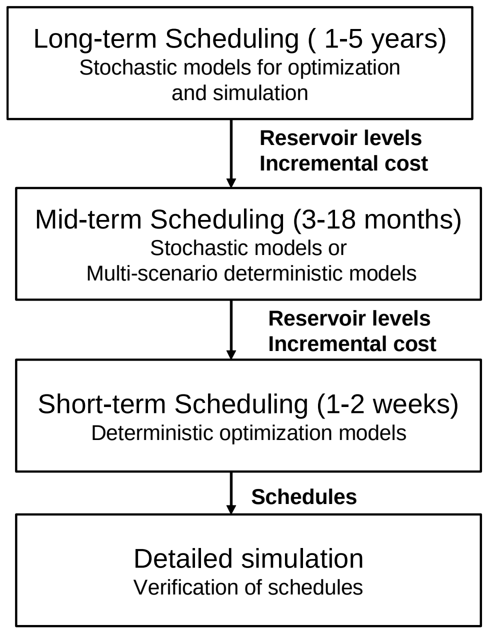

Figure 1: Scheduling problem decomposition

The long-term scheduling models are typically stochastic models for calculating an optimal strategy for hydro system operation. For the power producers, a long-term model may either be used for scheduling own resources in a market environment, or to do price forecasting. In the latter case, the complete system must be modelled.

The long-term models have to use aggregated reservoir models and do not provide boundary conditions for the short-term models with sufficient accuracy.

The medium term model may be seen as a link between the long and the short term scheduling models, a means of transforming results from the long term scheduling process to a form suitable for giving correct impulses to the short term scheduling process. The medium term model has a planning horizon of typically one year, and the same time increment (one week) and system model as the long term model. However, the medium-term models should have an approximate similar topology description in the optimization procedure as the short-term model in order to be able to supply suitable boundary conditions.

Short term scheduling is solved as a deterministic problem, with a sufficient time increment to support a more detailed system model than in the previous models. Coupling to the medium term model is based on an incremental water value description for the individual reservoirs [1]. Short term scheduling is the building block in the interaction with the market, and is used in the economic dispatch that gives the starting point for estimating cost for use in the real time market.

On all levels, the power producers will try to maximize their profit while taking into account the risk. Risk is handled through the contract markets while the interaction between the hydropower system and the market takes place in through the physical markets for energy and balancing power.

1.2 Market description

This section gives a brief introduction to the rules of the Nordpool market. Additional information including detailed market rules can be found in [2].

1.2.1 Spot market

The largest volume in the physical markets is cleared in the spot market. The market is cleared in the traditional crossing point of supply and demand. Each market participant is free to do bilateral trading as well. The clearing price together with the individual generation bid assign a certain volume of load to each generator in the system. The volumes assigned to the participants in the spot market are considered an obligation and deviation is settled according to the price in the real time market.

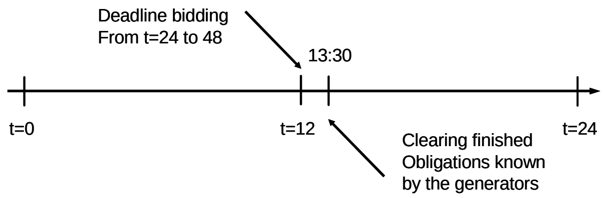

Figure 2: Spot market clearing

The spot market is cleared in advance for the following 24 hours starting at midnight, and is open for bids until 12:00 a.m. After 12:00 the clearing of supply and demand is performed, and around 13:30 the participants are informed about their obligations. It is possible to object to the result before 14:00 and then the objection must be answered upon before 14:30, this process may be repeated several times. Now each participant can decide to place a bid in the real time market.

1.2.2 Real time market

The real time market is a tool for the system operator to balance generation and consumption. As consumption for the day ahead is partly based on prognosis, deviation between expected and experienced generation and consumption is inevitably. Unexpected events happens both on the supply- and demand-side contributing to the mismatch. Bids to the real time market may be changed close to the operational time and may involve both the supply- and demand-side of the market. The bids are sorted after price as first criteria and then by arrival time.

There are two ways to participate in the real time market, actively or passively. If a market participant, by coincidence or by will, generates more power than his obligation in an hour of deficit, he will get paid the real time market price for the extra volume. In this case he is a passive participant. If a participant is active, he contributes with bids to this market, and regulates accordingly when the bids are activated.

1.2.3 Market and generation/Market interaction

The market rules impact on the planning and scheduling process in the generation companies. Daily deadlines must be kept, and different tasks are assigned to the short-term scheduling: preparing the bid, scheduling tomorrow when the obligation is known, continuously monitoring the system and for adjusting the real time bids. When finishing the scheduling for the day ahead the real time activity is largest. The different usage of the short-term model is shown in Fig. 3 below.

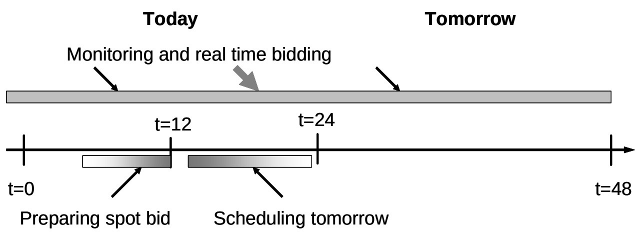

Figure 3: Short-term scheduling and markets

The first 24 hours are scheduled according to the obligation settled the previous day. During this period, the system must be monitored with respect to changing unforeseen conditions or activation of bids in the real time market that may impact on the optimal schedule of the units in the system. New revised bids may be posted to the real time market. Planning the bid for the day ahead spot market will normally take place close to the deadline in order to use the latest information. As a result at least 12 hours of the existing plan must be accounted for in the bid planning because it impacts on the system state at the beginning of the next bidding period. A brief introduction to bidding in the spot market can be found in [3]. Later, after the obligation for the next day is known, the generation scheduling must be performed using the obligation as a firm load minimizing the operation cost for complying with the load obligation.

The next step is to consider bids to the real time market. Partitioning in the real time market can increase income as prices are higher than in the spot market. The real time market can also be used to improve the generation schedule for the obligation from the spot market.

Besides the variation in the methods for doing this type of analysis, all approaches must take into account the current obligation and hence the generation schedule planned for the next period. The basic conditions for the real time bidding are the existing scheduling plan together with expectations of the value of the stored water in the reservoirs. A consequence analysis using short-term scheduling models will be very labour-intensive. Instead it is possible to utilize the result obtained when planning the next day generation schedules. These schedules can be seen as a starting point for evaluating the cost of regulation. How to obtain the schedules is described in the next chapter.

2 SCHEDULING MODEL

Providing the utilities with optimal scheduling plans for each generator in the system is a difficult task. Hydropower systems may have quite complex topologies with many cascaded reservoirs/power plants in the same river system. The reservoirs may have very different storage capacity with significant water travel time that makes the decisions coupled between several time steps. In other words, the decisions in one time interval have strong impact on what is possible to do in later time steps.

At the same time, it is critical that the calculated optimal generator schedules are feasible with respect to the constraints and details in the system. Ideally the generator schedules should be of such a quality that they could be transferred directly into an automatic generation control system (AGC) for implementation. Therefore modelling enough details is one of the big challenges for an optimization model that operates in an operative environment.

The goal of short-term scheduling is to minimize the cost for covering a load obligation or maximizing income if a market is present. This optimization must be performed while implementing the strategy from the long-term planning. The result is optimal generation schedules for the generation assets in the system. The challenge is in either case to find the exact balance between efficiency of the hydropower plants and the resource cost including the optimal unit commitment sequence. This is basically a nonlinear problem with state dependency introduced by the relation between the reservoir levels and the decision variables. An example is the efficiency of the plant; which depends on the net plant head, which depends on reservoir volume, which again depends on the value of the decision variables the model is searching for.

Solving this problem exact for practical sized models is difficult. Here a solution based on successive linear programming is proposed. This makes it possible to efficiently solve problems for large cascaded hydropower systems.

2.1 Successive linear programming

The solving strategy is iterative and each new iteration are based on the results from the previous iteration. This approach allows the handling of state dependency as well as nonlinear modelling of the hydropower system.

Linear programming is suited for solving the time coupled short-term hydropower scheduling problem, where the reservoir balances are the basic constraints. Normally one assumes that the reservoir level is unchanged by the decisions on gate and plant operation, assuming constant head.

This assumption is not adequate for practical use in more complex systems. Here decision variables, such as discharge through the hydropower plants, are so dependent on net plant head that ignoring the impact from the discharge decision on the reservoir levels may give infeasible generation schedules. This is where successive linear programming enters.

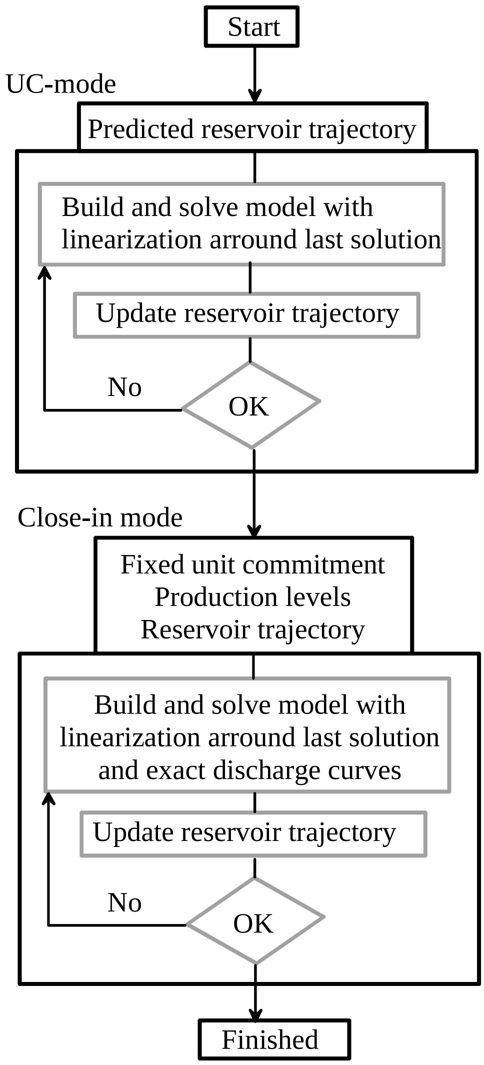

Figure 4: Simplified solution flow diagram for the applied successive linear programming approach.

Recalculation of reservoir trajectories makes it possible to account for this state dependency in plant modelling. The principle is illustrated in Fig. 4.

In addition to account for change in reservoir level dependent on the decision variables, it is important to consider the impact from the unit combination in hydropower plants with multiple units. So in addition to using the results from prior iterations, two different iteration modes are used.

In the first mode, the main objective is to find an optimal UC-decision for each individual unit in the system. In this mode head optimization can be included and one can choose to use an aggregated plant description or a unit-by-unit description including modelling of unit start-up cost [4].

Having an UC-plan for all units, the exact relation between discharge and generation can be calculated for each hydropower plant. Now, one can model the nonlinear operating point of the plant including internal losses in the waterways of each plant, minimum generation point and so fourth. This leads to the Close-in mode shown in Fig. 4.

Boundary conditions can be specific reservoir targets or incremental cost of water set for each individual reservoir [1]. A practical implementation of [1] can be found in [5]. A third option is to use dependent water values calculated through stochastic dual dynamic programming as in [6] and [7], or a multi scenario deterministic approach as in [8]. Using the latter approaches, the advantage is that the incremental cost of water is depending not only on the level in the current reservoir but also on the reservoir content of the other reservoirs in the system. Dependent water values are the preferred theoretical solution.

Applying this model in the interaction with the market makes it possible to be consistent regarding the signals from the long term strategy and consistent in the process of bidding in the markets and performing follow-up on changes in the hydropower system.

3 MATHEMATICAL FRAMEWORK

Bidding in the real time market is more complicated than in the spot market. In addition to being decoupled in time, likewise the spot market, the obligation received from the real time market clearing may vary in length from a fraction of an hour to several hours. From an optimization perspective the dimension of the problem becomes impractically large if all combinations (regulation level × expected length of regulation) are going to be evaluated, so one needs to look at more approximate solutions. One approach is to use a cost recovering principle.

3.1 Cost recovering

Provided that the value chain described in the introduction is established, it is meaningful to calculate the cost for deviation from this optimal solution. This is the costs that reflect the expected cost of regulation. Under perfect market conditions this would also be the cost per MWh offered in the bid to the real time market. Strategic considerations may come on top of the calculated marginal regulation costs.

3.1.1 Basic assumptions

A number of assumptions are needed in order to make the calculation of cost possible without solving each full scale optimization problem. These assumptions apply to:

- Reservoir balances
- Water values
- Start-up costs
- Integral constraints
- Sum constraints

The method is not obeying the reservoir constraints which are the main constraint connecting the reservoirs both within one time increment as well as over a period of time. In flexible systems this can be considered an adequate assumption but in constrained system this assumption will not apply. In the latter case the system or the part of the system that are constrained should be excluded from taking part in the regulation. From a practical point of view generators without flexibility in the system will not participate in the real time market. In systems with some flexible and some constrained parts the user may choose which plants and units that are allowed to participate in the regulation.

Water values are considered constant for the plants when the regulation cost is calculated.

Start-up cost must be handled in an approximate manner. The duration of the activation of a bid in the real time market may vary strongly and with it the marginal value of the start-up cost. Besides the importance of the ability to adjust the marginal start-up cost by varying the expected length of an activation of a bid this poses a real challenge when bidding in the real time market.

A typical constraint in a hydropower system is of integral type. Such constraints are difficult to handle because a change in one interval must result in a counter action in another interval.

A similar challenge arises if there is an important sum constraint in the system. An example is the constraint of maintaining an adequate level of spinning reserve

3.1.2 Calculation

The cost of regulation per MW is composed of a contribution from the efficiency change on the new and current generation level eventually together with start-up costs.

$$R_{MW} = \frac{R}{|\Delta P|} + \frac{S}{|\Delta P| \cdot t_s} \tag{1}$$

Where:

R_{MW} : Regulation cost per MW for the change ΔP

R : Regulation cost from efficiency change

S : Start-up costs

t_s : Number of intervals the start cost is distributed over

The basic idea is founded on confidence in the balanced interaction between the optimal schedule obtained by the short-term model and the marginal cost of water in the system (future expectation of what at least should be achievable). Put in other words you should at least maintain the resulting income from the current obligation seen in relation to the expected future income. Income from the current generation is:

$$I_0 = CP_0 - \frac{vv \cdot P_0}{\eta_0} \tag{2}$$

Where:

I_0	: Income from current generation
P_0	: Current generation
η_0	: Plant efficiency at p_0
C	: Price in the spot market
vv	: Marginal cost of water

The generation level is now changed from P_0 to P_1. The change in generation will trigger a change in the overall plant efficiency. Income in the new situation will be:

$$I_1 = CP_1 - \frac{vv \cdot P_1}{\eta_1} + R \tag{3}$$

Where:

I_1	: Income at regulated generation level
P_1	: Regulated generation level
η_1	: Plant efficiency at p_1
R	: Regulation cost

The requirement then is that (2) = (3) and the regulation cost is isolated:

$$R = C \cdot (P_0 - P_1) + vv \cdot \left(\frac{P_1}{\eta_1} - \frac{P_0}{\eta_0}\right) \tag{4}$$

The result for a single plant as cost/MW, can then be calculated from (1) and (4). If $P_1 > P_0$ the result is:

$$R_{MW}^{up} = -C + \frac{vv}{|\Delta P|} \cdot \left(\frac{P_1}{\eta_1} - \frac{P_0}{\eta_0}\right) + \frac{S}{|\Delta P|} \tag{5}$$

and if $P_1 < P_0$:

$$R_{MW}^{down} = C + \frac{vv}{|\Delta P|} \cdot \left(\frac{P_1}{\eta_1} - \frac{P_0}{\eta_0}\right) + \frac{S}{|\Delta P|} \tag{6}$$

A generator will normally have several plants in one or more water courses. In that case the calculation of R_{MW}^{up} and R_{MW}^{down} has to be performed for each plant and the wanted regulation level is in that case the minimum of (5) or (6) respectively. This problem is solved by an incremental stepwise loading until the wanted ΔP is reached. The number of steps needed depends on the step length.

$$MinR_{MW}^{down} = \sum_{i=1}^{n} \min(R_{MW\ i,1}^{down}, R_{MW\ i,2}^{down}, ..., R_{MW\ i,j}^{down})$$

Where:

i	: Index for stepnumber
n	: n = ΔP / *step length*
j	: Index for plants

Without start-up cost the cost function will be convex and incremental loading is possible. If the start-up cost is included within one interval, incremental loading works in most cases. If the start-up costs are distributed over several intervals a dynamic programming approach must replace the incremental loading approach.

Consider a plant with one unit. Then the following situations illustrate the possibilities and variation for regulation costs:

- $\Delta P>0$, $\eta_0>\eta$. Cost includes costs for ΔP and efficiency change on the rest of the volume. Typically +20% increase relative to spot market price are needed for $p_1 = p_{max}$.
- $\Delta P>0$, $\eta>\eta_0$. Happens when p_0 is lower than p_{best} (point of best efficiency) in the initial solution. Regulation is favoured and improves the existing solution. Regulation costs may be negative.
- $P_0=0$. In this case the cost will be calculated based on the p_{best} and corrected according to the current price in the interval.
- $\Delta P<0$, $\eta_0>\eta$. Down regulation results in lesser overall efficiency and results in positive costs.
- $\Delta P<0$, $\eta_0<\eta$. Down regulation from maximum improves efficiency until best efficiency is reached this type of regulation has low cost.
- $p_1=0$. The plant is stopped as part of the down regulation. It is assumed that it must be started on a later stage (not always true) and the costs for starting the unit again is added to the regulation cost.

4 EXAMPLE

4.1 Topology

The system used in the example consists of nine reservoirs, seven plants with thirteen units and two gates. The total available generation capacity for this system is 858 MW.

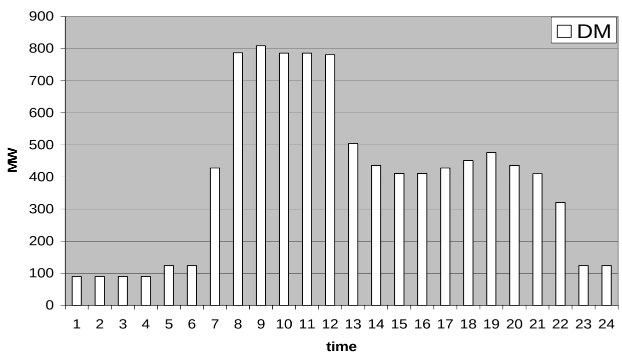

Figure 5: Obligation in the spot market

The generation in the spot market is shown in Fig. 5. In this example we are only looking at the first time interval.

4.2 Loading the generation units

Fig. 6 and 7 show the loading of the units for volume scenario 1 to 4 (0 to +75 MW) and 15 to 20 (+453 MW) in Table 1. The white columns in Fig. 6 are the generation on the daily market. The obligation from the spot market is 90 MW, see Fig. 5, and therefore the system has a reserve of 768 MW for up regulation and 90 MW for down regulation in the first time interval. All available capacity must be reported to the real time market. Only three units are running in the first time interval.

For volume scenario 1 the cheapest up regulation of 15 MW is on unit 9. This up regulation (V1) is shown with a dotted pattern in the figure.

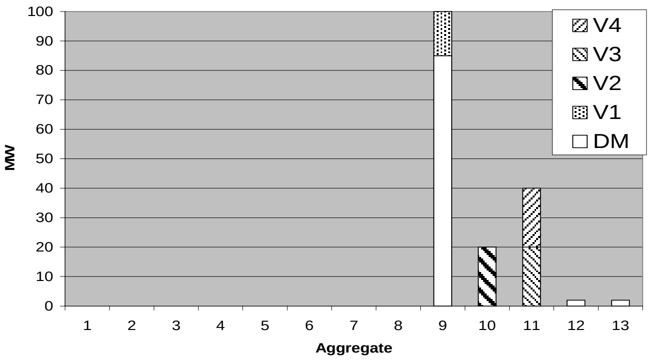

Figure 6: Loading of the units scenario 1 to 4.

The columns marked "V1 to 14" in Fig. 7 are the total uploaded volume for scenario 1 to 14. The figure shows the last six uploading scenarios. After the volume in scenario 20 is distributed, all the units run at maximum generation.

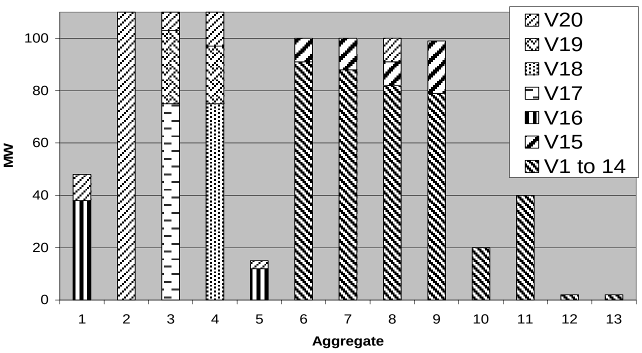

Figure 7: Loading of the units scenario 15 to 20.

Table 1 shows the calculated real time bid prices for the first time interval. The second column is the regulated volumes, values above zero are up regulations, and values below zero are down regulations. Scenario number one gives the first regulated volume, scenario number two the next regulation and so on.

The third column in the table shows the real time bid prices calculated as described in Chapter 3. For up regulation the bid price is given as the regulation cost (5) plus the spot price and for down regulation (6) minus the spot price.

The bid prices in the real time market must be given in ascending order for up regulation. The cost R_i in the fourth column in Table 1 is calculated for up regulation as:

$$R_1 = \max(SP, C_1) \tag{8}$$

$$R_i = \max(R_{i-1}, C_i) \qquad i = 2, n \tag{9}$$

Where:

SP : Spot price

C_i : Calculated cost for scenario i

n :Number of up regulation scenarios

For down regulation, the producers get paid the difference between the market price and the bidding price. Let the total number of regulations be m. The costs in the fourth row R_i are calculated for down regulation as:

$$R_{m-n+1} = \min(SP, C_{m-n+1}) \tag{10}$$

$$R_i = \min(R_{i-1}, C_i) \qquad i = m - n + 2, m \tag{11}$$

The two last volume scenarios in Table 1 are down regulations. The first bid on -25 MW suggests letting one unit run on minimum generation level. The second bid (-90 MW) requires stopping the three units that are running.

Scenario number	Volume (MW)	Real time price (Euro)	Real time scheme (Euro)
1	15	23.77	23.77
2	20	23.80	23.80
3	20	24.69	24.69
4	20	21.18	24.69
5	30	27.06	27.06
6	20	21.64	27.06
7	20	22.59	27.06
8	20	23.28	27.06
9	20	30.21	30.21
10	20	22.30	30.21
11	20	22.61	30.21
12	20	23.17	30.21
13	20	24.02	30.21
14	50	24.76	30.21
15	50	23.93	30.21
16	50	26.42	30.21
17	75	24.96	30.21
18	75	24.96	30.21
19	50	24.10	30.21
20	153	25.08	30.21
21	-25	21.84	21.84
22	-65	23.91	21.84

Table 1: Regulation cost for the first time interval.

Table 2 is an example of a bid in the real time market valid for the first time interval. Volumes that have nearly the same real time bid price are summarized.

Price	Volume (MW) t=0
30.5	603
27.5	90
25.0	40
24.0	35
SP	---
21.5	-90

Table 2: Real time scheme.

4.3 Discussing costs

The calculated cost in Table 1 will not always be in ascending order for up regulation. If a unit is producing below best efficiency point, it can be profitable to regulate the unit up to best point. This gives a low regulation cost. An example of this is shown if Fig. 7 where the fourth unit is up regulated close to best point in the 19th scenario. The next regulation of this unit is up to max generation and this gives a higher cost.

It can be profitable to regulate the units if the schedules are smoothened; this means that the schedule is the same for several hours. This is preferred by the generators, and therefore a lower bid than the calculated regulation cost can still be acceptable.

The peaks, for instance row 5 and 9 in Table 1, happen when a new unit had to be started.

A minimum generation constraint on a unit can contribute to a higher regulation cost. If e.g. a plant has two units and only one is running, a low bid on up regulation can make it necessary to start the second unit and force the unit that is already running to run with lesser efficiency. The calculated cost in row 9 (30.21 Euro) in Table 1 is so high because a new unit had to be started, and the other unit on the same plant was regulated down to run on a lower efficiency. For this example it would be profitable to increase the bid even more so both the units on the plant can run with high efficiency.

4.4 Discussion duration of bid activation

The duration of a bid is in the example assumed to be one hour; this means that if the unit is started, all the start cost must be covered in this hour. How long the duration of the bid becomes, is not known when the bid is activated.

If the duration of the bid is more than an hour, the start cost can be divided on the number of hours the bid is active. Note that there is a risk involved choosing t_s longer than an hour. As mentioned above, the obligation is not certain to be more than an hour, so the start up cost are not guaranteed to be covered. But if the bidding price is lesser, it is more likely to get the bid so sometimes it is worth the risk.

5 CONCLUSION

The paper presented a technique that based on consistent value chain in hydropower operation and scheduling, can be used for decision support for bidding in the real time market. The module has been tested both by researchers and generation companies.

The current development in the electricity sector in many countries around the world will increase the utility value of the proposed method. Hydropower units are important in the power system and should be encouraged to participate in the market for secondary reserve and by that contribute to a cleaner environmental by reducing the use of fossil fuels.

The advantage of the proposed technique is that it is based on results from a process daily performed in many power companies. The technique is fast and can estimate regulation cost for given scenarios. Thus make it possible to the operator to adjust settings iteratively and thereby support the decisions on bid levels and bid prices in the real time market.

Recommendation for future work is to extend the development with a more robust minimization technique for handling start-up costs. This would make it easier to investigate the performance of the technique, but regarding the value of the result this extension is less important. Another improvement is to handle wear cost associated with running hydropower turbines at high or low loads. Finally forbidden zones, that originates from generator loads resulting in vibration and stress in the turbine, should be included in the concept resulting in better feasibility of the regulation distribution plans.

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