Short Term Hydro Power Planning Coordinated with Wind Power in Areas with Congestion Problems

J. Matevosyan, M. Olsson and L. Söder

Abstract—In this paper a day-ahead planning algorithm for a multi-reservoir hydropower system coordinated with wind power is developed. Coordination applies to real situations, where wind power and hydropower are owned by different utilities, sharing the same transmission lines, though hydropower has priority for transmission capacity. Coordination is thus necessary to minimize wind energy curtailments during congestion situations. The planning algorithm accounts for the uncertainty of wind power forecasts and power market price uncertainty. Planning for the spot market and the regulating market is considered in the algorithm. The planning algorithm is applied to a case study and the results are summarized in the paper.

Index Terms—wind power production, hydro power production, wind forecast uncertainty, power market, stochastic optimization

I. INTRODUCTION

THE best conditions for the development of wind farms are in opened, remote areas, far from the load centers. The transmission system in such areas is usually not well developed, so the growth of wind farms is hindered by congestions on the transmission lines. Furthermore a part of the transmission capacity of the power lines might already be reserved for conventional power plants situated in the same area.

As wind power production depends on wind speed, the full load hours of a wind farm are only 2000-4000 hours per year. Moreover wind power production peaks do not always occur during periods with insufficient transmission capacity. Therefore reinforcing a transmission network in order to remove a bottleneck completely cannot be economically justified. It is possible, for example, to curtail excess wind energy during congestions on the transmission lines [1], [2]. Another alternative is to store excess wind energy. Battery storage for large-scale wind farms is still rather expensive, but existing conventional power plants with fast production control capabilities and sufficient storage capacity, for example hydro power plants, could be used instead.

The coordination of wind power and hydro power has been studied earlier in connection with several different problems. In [3] the coordination of wind farms with hydro power plants is considered in generation expansion planning. Two investment possibilities are compared in [3]: a new hydro power plant (HPP) versus a new wind farm (WF). In [4] and

[5] the effect of wind power on the market prices is analyzed. The research in [4] and [5] is directed towards assisting hydro power utilities considering investments in wind power. In [6] the coordinated operation of several geographically spread WFs and HPP sharing the same transmission capacity is simulated over a period of several years, considering wind and water inflow uncertainty. The simulation uses a coordination strategy that maximizes wind power penetration. The paper shows that due to coordination significantly more wind power can be developed in the studied area. In [7] several coordination strategies are suggested which consider separate ownership of wind power and hydro power. The coordination strategies are then evaluated using historical data of the hydro power system operation and wind speed measurements from the studied site. None of these papers, however, treat hydro power production planning for daily operation, considering the coordination with wind power.

In this paper a daily planning algorithm is developed for a multi-reservoir hydro power system coordinated with a wind farm. The planning algorithm based on one of the coordination strategies developed in [7]. Wind power and hydro power are assumed to be owned by different utilities. It is assumed that the wind farm and the hydro power system share the same transmission lines, but that the hydro power utility has priority to use the transmission capacity. Consequently, coordination is necessary in order to minimize wind energy curtailments during congestion situations on the transmission lines. The wind power utility is assumed to be paying the hydro power utility for the coordination service.

The purpose of the coordinated planning algorithm developed in this paper is to provide the hydro power utility with an optimal production plan for each coming day, considering the uncertainty in the wind power forecast and the uncertainty of power market prices. The planning algorithm considers a spot market and a regulating market. The optimization problem is formulated as a two-stage stochastic program with recourse [8].

The paper is structured as follows: in Section II a flow chart for the developed hydro power planning algorithm, which considers coordination with wind power, is presented and explained in detail in the successive subsections. The developed algorithm is then applied in a case study in Section III. The results obtained when applying coordinated planning are compared to the results when uncoordinated planning is used. Section IV summarizes the main conclusions of the study and plans for future work.

The authors would like to acknowledge the financial support for this project from Swedish Energy Agency.

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II. COORDINATION STRATEGY WITH WIND POWER

In this paper a hydro power system is assumed to be coordinated with a WF in the following way: for each hour of the coming day, if transmission congestion is expected, the hydro power utility decreases its planned production depending on constraints of the hydro reservoirs. Hydro power is then retained in the reservoirs and the wind farm can use available transmission capacity. Each megawatt (MW) of stored hydro power corresponds to 1 MW of transmission capacity that is made available for excess wind energy. Stored hydro power can then be used in the hours without congestion. The wind power utility is assumed to pay to the hydro power utility for this service. Therefore it is important in the coordinated planning to keep track of hydro power production changes due to wind power and congestions on the transmission lines. For this purpose the planning algorithm is divided into two parts:

- 1) base case hydro power planning for the spot market without consideration of wind power;
- 2) re-planning of hydro power production for the spot market and the regulating market considering wind power.

The first part of the planning algorithm (base case planning) is optimization under spot price uncertainty. This part is formulated as a stochastic program. The second part of the planning algorithm (re-planning) is optimization under the power market price uncertainty and the wind power production uncertainty. The optimization problem is formulated as a two-stage stochastic program with recourse [8], where the first stage corresponds to the planning for the spot market, and the second stage corresponds to the planning for the regulating market.

The following assumptions are made for the planning:

- The hydro power utility and the wind power utility are price takers.
- The hydro power planning for the coming day is assumed to be conducted at 11:00 the day before, in order to place the bids on the spot market that closes at 12:00.
- Cooperative behavior of the hydro power utility is assumed.

In addition to the coming day the rest of the current week is also included in the planning. This is done to account for the wind power that might be produced during the following days in the re-planning part of the planning algorithm. However, only the planning results for the coming day are used for bidding on the spot and regulating markets. Planning is then repeated for each following day.

Hydro reservoir content at the end of the week is fixed in accordance with mid-term planning [9]. It is possible to use a more flexible representation of the end conditions for hydro reservoirs. In the short term hydro planning the so called water value function is often used. The water value function shows the expected future income of the hydro power utility as a function of hydro reservoir content [9]. However, in a discussion with hydro producers, it was pointed out that by using the water value function the effect on operation of the hydro power system from coordination with the wind farm would extend to longer periods. Operation of the hydro power system would then be strongly affected by coordination with

wind power. By fixing reservoir content at the end of the week to a certain value, the effect of coordination does not extend beyond that week.

The planning is performed for each day in accordance with the flow chart in Fig. 1. The flow chart is discussed in detail in the following subsections.

Fig. 1. Flow chart of the daily hydro power planning algorithm in coordination with wind power

A. Initial data

For the day to which the planning refers (the planning day) input data (blocks 1-2) are loaded: the water inflow, the initial reservoir content at the beginning of the planning day and the final reservoir content at the end of the current week, the spillage and the discharge in the preceding hours to account for the water delay time between the reservoirs and the spot prices.

In order to deal with uncertainty of the spot prices a set of the spot price scenarios is used. Each spot price scenario corresponds to a particular realization of the stochastic process. Here, to generate a set of spot price scenarios, sampling from historical spot price time series is employed. Equal probability is assigned to each spot price scenario.

The set of spot price scenarios form a scenario tree. The root node of the tree corresponds to a known spot price at the time of planning. The tree then branches into the nodes of the subsequent hours. Each node has a unique predecessor node but possibly several successors. The branching continues to the nodes of the last hour of the planning day [10]. The number of the nodes for the last hour of the planning day corresponds to the total number of spot price scenarios. The schematic structure of the spot price scenario tree is shown in Fig. 2. The stochastic optimization (block 3) finds an optimal decision i.e. hydro power production bids to the spot market for each spot price scenario. The stochastic decision process then has the same tree structure as the spot price scenario tree.

Fig. 2. Spot price scenario tree.

B. Hydro Power Planning, Base Case

This subsection discusses modelling details of the base case hydro power planning without consideration of wind power (block 3). Generally, hydropower production is planned differently by different utilities. There is a large variation in modelling, for example regarding the degree of detail, representation of uncertainties. Furthermore, the strategies are not always optimal because of unexpected events, for example generator outages or participation in the regulating market.

A hydro power production characteristic of each unit in a hydro power plant is a family of nonlinear functions of the respective reservoir head, efficiency of the turbine/generator set and water discharge. The generation functions of all production units form a family of nonlinear and non-concave production curves for each specified value of the water head [11].

In most planning methods the head dependence is neglected to avoid nonlinearities. This simplification allows the use of a single production curve. In this paper, for simplicity, the hydro power production characteristic is further approximated by a concave piecewise linear function, as shown in [12]. The local best efficiency points of the true generation function and the point of maximum discharge are used as the breakpoints, Fig. 3. The slope of each linear segment is called the production equivalent, μ_{is} . More detailed methods of production characteristic modelling are given in [13] and [11].

Water inflow uncertainty is usually neglected in short-term hydro power planning in order to shorten computational time [11], [13]. As a rule it is considered in mid-term or long term planning [9].

The objective of the hydro power producer is to maximize the expected income from produced power:

$$\max z^b = \sum_{k \in K} \sum_{n \in N_k} c^s(k, n) p^n(k, n) \sum_{i \in I} \sum_{s \in S_i} u_{is}(k, n) \mu_{is}, \quad (1)$$

where $u_{is}(k, n)$ is the water discharge at hour k at node n of the decision scenario tree, at a power plant i , in a segment s of the production function, S_i is an index set of the segments of the hydro power production curve of plant i , $c^s(k, n)$ is a spot price at hour k , at node n of the spot price scenario tree, $\sum_{i \in I} \sum_{s \in S_i} u_{is}(k, n) \mu_{is}$ is, the power that the hydro power producer would bid on the spot market at hour k , for

the price $c^s(k, n)$, $p^n(n)$ is the probability of the node n in price scenario tree and N_k is a subset of nodes of the spot price scenario tree at hour k .

The hydrological constraints describe the couplings between adjacent HPPs in a multi-reservoir hydro power system.

$$\begin{aligned} x_i(k+1, \tilde{n}) &= x_i(k, n) - \sum_{s \in S_i} u_{is}(k, n) - y_i(k, n) + w_i(k) \\ &+ \sum_{j \in \Omega_i} \left[\sum_{s \in S_j} u_{js}(k - \tau_{ij}, n_{\tau_{ij}}) + y_j(k - \tau_{ij}, n_{\tau_{ij}}) \right], \\ \forall i \in I, \forall k \in K, \forall n \in N_k \end{aligned} \quad (2)$$

where $x_i(k, n)$ is reservoir content at the hydro plant i at hour k at node n , $y_i(k, n)$ is water spillage from plant i at hour k at node n , $w_i(k)$ is water inflow to the reservoir i at hour k , Ω_i is index set of the HPPs directly upstream of plant i , $\tilde{n}$ is a child node of the node n and $n_{\tau_{ij}}$ is a relative node of the node n at hour $k - \tau_{ij}$, see Fig. 2. In equation (2) $x_i(k+1, \tilde{n})$, $u_{is}(k, n)$, $u_{js}(k, n)$, $y_i(k, n)$, $y_j(k, n)$, $x_i(k, n)$ are variables, $w_i(k)$ is a parameter.

The reservoir content of a particular HPP is affected by water spillage and discharge of the HPPs directly upstream. The delay time τ_{ij} between HPP j and HPP i directly downstream is assumed to be defined in H_j hours and M_j minutes. The discharge considering the delay time is then expressed as:

$$\begin{aligned} u_{js}(k - \tau_{ji}, n_{\tau_{ij}}) &= \frac{M_j}{60} u_{js}(k - H_j - 1, n_{H_j - 1}) \\ &+ \frac{60 - M_j}{60} u_{js}(k - H_j, n_{H_j}), \\ \forall j \in \Omega_i, s \in S_j, k \in K, \forall n \in N_{k - \tau_{ij}} \end{aligned} \quad (3)$$

By analogy, the spillage considering the delay time can be determined [14].

Fig. 3. Production function of the hydro power plant.

The power transmission from a studied site where a WF and hydro power system are situated, is limited so that

$$\begin{aligned} \sum_{i \in I_c} \sum_{s \in S_i} u_{is}(k, n) \mu_{is} - D(k) &\leq \bar{P}_{12}, \\ \forall k \in K, \forall n \in N_k \end{aligned} \quad (4)$$

where $D(k)$ is the hourly load in the studied site and $\bar{P}_{12}$ is the power transmission limit from the studied site and I_c is the index set of HPPs sharing same transmission capacity with wind farm. Both parameters are assumed deterministic in this paper.

There are also reservoir content, spillage and discharge limitations:

$$0 \leq x_i(k, n) \leq \bar{x}_i; \quad 0 \leq y_i(k, n) \leq \bar{y}_i, \quad (5)$$

$$\forall i \in I, \forall k \in K, \forall n \in N_k$$

$$0 \leq u_{is}(k, n) \leq \bar{u}_{is}, \quad (6)$$

$$\forall i \in I, \forall s \in S_i, \forall k \in K, \forall n \in N_k.$$

where $\bar{u}_{is}$ is maximum discharge at plant i at segment s of the production function, $\bar{y}_i$ is maximum spillage at plant i and $\bar{x}_i$ is maximum reservoir content.

The initial reservoir content is assumed known and the reservoir content at the end of the planning period is fixed in accordance with the mid-term production planning, as discussed in the beginning of this section:

$$x_i(0) = x_i^o; \quad x_i(n, K_{last}) = x_i^{last} \forall n \in N_k \quad (7)$$

where x_i^o is initial reservoir content at plant i , x_i^{last} is reservoir content at the end of the period at plant i , K_{last}^{day} is the last hour in the planning day $K_{last}^{day} \subset K$.

The solution to of the base case hydro power planning problem described in equations (1)-(7): the planned water discharge, HPP production, spillage and reservoir content (block 4), are passed as parameters to the re-planning program that includes coordination with wind power (block 9).

C. Wind Power ARMA Forecast Error Scenarios

This subsection discusses blocks 5-7 of the flow chart in Fig. 1. These blocks prepare additional input data for the re-planning program (block 9).

A wind speed forecast for a planning day can be obtained from the source such as numerical meteorological programs. A wind speed forecast is never perfect and the forecast error should be considered.

A model for wind speed forecast error (block 5) is developed in [15]. It is assumed that data concerning accuracy of the forecast are known. The model then simulates possible outcomes of the wind speed forecast error whose stochastic properties are close to those of the actual wind speed forecast error. The model is based on Auto Regressive Moving Average series (ARMA), [16], defined as:

$$\Delta V(0) = 0; \quad Z(0) = 0$$

$$\Delta V(k) = \alpha \Delta V(k-1) + Z(k) + \beta Z(k-1) \quad (8)$$

where $\Delta V(k)$ is wind speed forecast error in k -hour forecast, $Z(k)$ is random Gaussian variable with standard deviation σ_Z , α and β are the parameters. The parameters are identified using the least square fitting method, minimizing a difference between sample forecast error variance, based on data from the site, and modeled forecast error variance. For further details see [15].

By sampling from the ARMA model the set of wind speed forecast error scenarios can be generated. Equal probability is assigned to each scenario. The wind speed forecast error scenarios form a scenario tree.

A possible outcome of wind speed forecast error $\Delta V(k)$, corresponding to hour k and node m of the forecast error

scenario tree is denoted $\Delta v(k, m)$. A wind speed $v(k, m)$ at hour k and node m of the scenario tree is calculated as a sum of wind speed forecast error $\Delta v(k, m)$ and wind speed forecast $v^f(k)$ for hour k :

$$v(k, m) = v^f(k) + \Delta v(k, m), \forall m \in M_k \quad (9)$$

where M_k is a subset of nodes of the forecast error scenario tree at hour k . Note that the wind speed scenario tree will then have the same structure as the wind speed forecast error scenario tree.

Obtained wind speed scenarios are then converted to wind power production scenarios (block 6) using production functions, the so called power curves of the respective wind turbines of the WF [17]. Wind power production scenarios form a scenario tree with the same structure as the wind speed scenario tree. Wind power production at hour k , node m of the wind power production scenario tree is denoted $\bar{P}_w(k, m)$.

The wind power scenario model is only applied for the planning day that is for $k \leq K_{last}^{day}$, where K_{last}^{day} is the last hour of the planning day. Wind power forecasts for a longer time horizon are highly unreliable. For the remaining days of the current week included in the planning, monthly average wind power production P_w^{av} is used instead of wind power scenarios¹, shown in Fig. 4. It is calculated from the monthly average wind speed derived from statistical data.

Fig. 4. Example of wind power production scenarios for 60 MW wind farm for the planning day (Thursday in this example) and for the rest of the current week included in planning

D. Regulating power price model

This subsection discusses block 8 in Fig. 1. The model for generation of regulating market price scenarios is based on autoregressive integrated moving average (ARIMA) [18] and Markov processes [19]. This model is fully described and motivated in [20] and a brief description follows.

The regulation power price series used in this paper are characterized by the following:

- There are different prices for upward and downward regulation.
- Not all hours have defined upward and/or downward prices. The prices are defined if the corresponding quantities of regulating power are larger than zero.

¹In the following subsections the equations are written in general form, however, for all $k > K_{last}^{day}$ $\bar{P}_w(k, m)$ should be substituted by P_w^{av}

- The occurrence of upward and downward regulating prices are negatively correlated.
- If defined, the regulating prices have bounds set by the spot price: the upward price is always higher and the downward price is always lower than the spot price.

The models for upward and downward regulation are partly separate, but are based on the same mathematics. The developed regulating power price model takes the occurrence of undefined prices into account by modelling the regulating power prices $c^r(k)$ for hour k as

$$c^r(k) = \begin{cases} a(k), & b(k) = 1, \\ \text{not defined}, & b(k) = 0, \end{cases} \quad (10)$$

where $b(k)$ is a binary stochastic variable. The continuous part of the model, $a(k)$, is modeled using an ARIMA process, while the discrete part, $b(k)$, is modeled with a Markov process.

The continuous part reflects the behavior of the prices when they are defined and can be expressed in terms of the spot price and the difference between the spot and regulating price as $a(k) = c^s(k) + \delta(k)$. The spot prices $c^s(k)$ are known at this stage, while $\delta(k)$ are stochastic variables modeled with an ARIMA(2,1,2) process:

$$\begin{aligned} (1 - B)\Phi(B)(\delta(k) - \delta^{av}) &= \Theta(B)Z(k), \\ \Phi(B) &= 1 - \phi_1 B - \phi_2 B^2, \\ \Theta(B) &= 1 + \theta_1 B + \theta_2 B^2. \end{aligned} \quad (11)$$

where B is a backshift operator, i.e. $Bx(k) = x(k-1)$, $\delta(k)$ is price difference at hour k , Φ is AR polynomial of ARMA process, Θ is MA polynomial of ARMA process.

The correlation between the occurrence of upward and downward prices are handled by using Markov processes to model $b(k)$, that is $b^u(k)$ and $b^d(k)$ for upward and downward prices respectively. Four states covering all possible combinations of $b^u(k)$ and $b^d(k)$ can be identified: $(b^u(k), b^d(k)) = \{(0,0), (0,1), (1,0), (1,1)\}$, with associated probabilities for transition between states.

The parameters of $a(k)$ and $b(k)$ are estimated using historical price series.

E. Electricity price scenario tree

As was described in subsection II-B, the planning is conducted before the spot market closure, and the uncertainty of spot prices, upward and downward regulating prices should therefore be considered. The stochastic power market price process ξ is then three-dimensional:

$$\xi = \{C^u(k), C^d(k), C^s(k); \forall k \in K\}, \quad (12)$$

where $C^u(k)$, $C^d(k)$, $C^s(k)$ denote respectively the stochastic upward regulating price, the stochastic downward regulating price and the stochastic spot price at hour k . The regulating price model described in the previous subsection requires that the spot prices are known when generating the regulating price scenarios. In this model, observed historical price series from the Nordic spot market are used as spot price scenarios. From each spot price scenario, one upward regulation price scenario,

and one downward regulation price scenario are generated by sampling from the ARIMA model presented in the previous subsection. Therefore three different types of prices in the expression (12) are available. Equal probability is assigned to each power market price scenario. The power market price scenarios form a scenario tree. An outcome of the three dimensional stochastic market price process ξ , corresponding to hour k and node n of the power market price scenario tree is denoted $c^u(k, n)$, $c^d(k, n)$, $c^s(k, n)$.

F. Scenario reduction and bundling

Wind power production scenarios and power price scenarios generated as described in the previous subsections form scenario trees. To assure that stochastic properties of the process are represented correctly many scenarios should be generated.

The computational effort for solving scenario-based optimization models depends on the number of scenarios. Therefore it is necessary to reduce the original scenario tree so that it has a smaller number of scenarios but its stochastic properties are not changed significantly.

The scenario reduction approach applied here (block 7) is presented in detail in [10]. The scenario reduction algorithm reduces and bundles the scenarios in a tree using the Kantorovich metric, which assures that as many scenarios as possible are reduced without violating a given tolerance criteria.

G. Hydro power re-planning coordinated with wind power

In the re-planning part (block 9) of the planning algorithm, the base case hydro power production plan (block 3-4) is changed to account for wind power. If, according to the base case hydro power production plan (block 4) and wind power production scenario (block 7), transmission congestion is expected, then planned hydro power production could be decreased, in order to allow the WF to use available transmission capacity. For each hour k the subset of node combinations (n, m) of the market price scenario tree and the wind power production scenario tree, at which congestion on the transmission lines is expected, can be defined from the following condition:

$$\begin{aligned} \text{if } \sum_{i \in I_c} \sum_{s \in S_i} \mu_{is} u_{is}(k, n) + \bar{P}_w(k, m) - D(k) &> \bar{P}_{12}, \\ \text{then } k, n, m &\in K^c(n, m). \end{aligned} \quad (13)$$

For each hour k the subset of node combinations (n, m) , at which no congestion on the transmission lines is expected, can be defined from the condition:

$$\begin{aligned} \text{if } \sum_{i \in I_c} \sum_{s \in S_i} \mu_{is} u_{is}(k, n) + \bar{P}_w(k, m) - D(k) &\leq \bar{P}_{12}, \\ \text{then } k, n, m &\in K^{nc}(n, m), \end{aligned} \quad (14)$$

where $\sum_{i \in I_c} \sum_{s \in S_i} \mu_{is} u_{is}(k, n)$ is planned hydro power production in a plant i , at hour k according to the base case, $\bar{P}_w(k, m)$ is potential wind power production at node m of the wind power production scenario tree, at hour k and $\bar{P}_{12}$ is available transmission capacity.

It is assumed that the hydro power producer is paid for reducing power production at the stations I_c , as this relieves congestion on the transmission lines and allows the WF to produce energy that would otherwise be curtailed. The price c , SEK/MWh, is estimated as yearly average economic losses of the wind power utility due to wind energy curtailments, based on historical data:

$$c < \frac{\sum_{k \in K_c} c^s(k) (\sum_{i \in I_c} P_i^h(k) + \bar{P}_w^h(k) - P_{12})}{\sum_{k \in K_c} (\sum_{i \in I_c} P_i^h(k) + \bar{P}_w^h(k) - P_{12})} \quad (15)$$

where $P_i^h(k)$ is hydro power production in stations I_c without coordination, obtained from historical data, $\bar{P}_w^h(k)$ is wind power production calculated from historical wind speed data and $c^s(k)$ is a spot price for the same period in the past. The numerator corresponds to the economical losses due to wind energy curtailments according to historical data and the denominator corresponds to total wind energy curtailments in that period. Thus c is the upper limit for the price that the wind power utility is prepared to pay the hydro power utility for the coordination. The exact value of the coordination service price depends on the agreement between the wind power utility and the hydro power utility. More flexibility could be added, for example by estimating c as monthly average loss due to wind energy curtailments. Different value of c would then apply to each month.

In the re-planning part of the planning algorithm two new variables are introduced: additional discharge $\Delta u_{is}(k, n)$ and power production decrease $\Delta P_{is}(k, n)$. The new variables make it possible to track changes in the coordinated production plan compared to the base case plan. Also, as wind power production forecast is uncertain, hydro power production adjustments are planned for each wind power production scenario, $P_{is}^{up}(k, n, m)$ and $P_{is}^d(k, n, m)$. Bids for these adjustments can be made later during the day as upward or downward regulation bids to the regulating market, when wind power forecast would become more precise. The re-planning is thus formulated as a two-stage stochastic optimization program with recourse [8] and hydro power production adjustments are the recourse variables. The recourse variables will emerge in the transmission constraints, as will be shown further in this paper.

The stochastic optimization determines an optimal decision that is hydro power production bid to the spot and regulating markets for each combination of power market price and wind power production scenarios. The stochastic decision process then has a tree structure consisting of combinations (n, m) of nodes of the market price scenario tree and wind power production scenario tree as shown in Fig. 5.

The objective of the hydro power producer is, as in the base case planning (1), to maximize the expected income of the hydro power producer:

$$\max z^{tot} = z^c + z^{up} - z^d \quad (16)$$

where z^c is the expected income from trading on the spot market and from coordination with wind power and z^d and z^{up} are expected recourse costs/income from trading respectively downward and upward hydro power production adjustments

on the regulating market. These are defined as follows:

$$z^c = \sum_{k \in K} \sum_{n \in N_k} (c^s(k, n) q^s(k, n) + \sum_{i \in I_c} \sum_{s \in S_i} c \cdot \Delta P_{is}(k, n)) p^n(n), \quad (17)$$

$$z^d = \sum_{k \in K} \sum_{n \in N_k} \sum_{m \in M_k} (q^d(k, n, m) \cdot p^n(n) \times p^m(m) \cdot c^d(k, n)), \quad (18)$$

$$z^{up} = \sum_{k \in K} \sum_{n \in N_k} \sum_{m \in M_k} (q^{up}(k, n, m) \cdot p^n(n) \times p^m(m) \cdot c^{up}(k, n)), \quad (19)$$

where $p^m(m)$ is probability of the node m in wind power production scenario tree, $q^s(k, n)$, $q^d(k, n, m)$ and $q^{up}(k, n, m)$ are bids on the spot market and downward and upward regulation bids on the regulating market respectively. These are defined as follows:

$$q^s(k, n) = \sum_{i \in I} \sum_{s \in S_i} ((u_{is}(k, n) + \Delta u_{is}(k, n)) \mu_{is} - \Delta P_{is}(k, n)), \quad (20)$$

$$q^d(k, n, m) = \sum_{i \in I} \sum_{s \in S_i} P_{is}^d(k, n, m), \quad (21)$$

$$q^{up}(k, n, m) = \sum_{i \in I} \sum_{s \in S_i} P_{is}^{up}(k, n, m), \quad (22)$$

where $P_{is}^{up}(k, n, m)$ and $P_{is}^d(k, n, m)$ are upward and downward adjustments at HPP i and segment s of the production function.

The hourly bids $q^s(k, n)$ to the spot market are in MWh/h at price $c^s(k, n)$ in SEK/MWh. Bids to the regulating market are assumed to be made as close to the operating hour as possible. Therefore it is assumed that the realization of the wind power production scenario $\bar{P}_w(k, m^*)$ for the operating hour k is known with certainty and corresponding quantities $q^d(k, n, m^*)$ and $q^{up}(k, n, m^*)$ can be chosen to bid on the regulating market. In the Nordic market the regulating market closure is half an hour before the operating hour.

The hydrological constraints (2) are adjusted as follows:

$$\begin{aligned} x_i(k+1, \tilde{n}, \tilde{m}) = & x_i(k, n, m) - \sum_{s \in S_i} (u_{is}(k, n) - y_i(k, n) \\ & + w_i(k)) + \sum_{j \in \Omega_i} \left[\sum_{s \in S_j} u_{js}(k - \tau_{ij}, n_{\tau_{ij}}) + y_j(k - \tau_{ij}, n_{\tau_{ij}}) \right] \\ & + \sum_{s \in S_i} \left(\frac{\Delta P_{is}(k, n) - P_{is}^{up}(k, n, m) + P_{is}^d(k, n, m)}{\mu_{is}} \right. \\ & - \Delta u_{is}(k, n)) \\ & - \sum_{j \in \Omega_i} \sum_{s \in S_i} \frac{\Delta P_{js}(k - \tau_{ji}, n_{\tau_{ji}}) + P_{js}^{up}(k - \tau_{ji}, n_{\tau_{ji}}, m_{\tau_{ji}})}{\mu_{js}} \\ & + \sum_{j \in \Omega_i} \sum_{s \in S_i} \left(\frac{P_{js}^d(k - \tau_{ji}, n_{\tau_{ji}}, m_{\tau_{ji}})}{\mu_{js}} + \Delta u_{js}(k - \tau_{ji}, n_{\tau_{ji}}) \right) \end{aligned} \quad (23)$$

$\forall i \in I, \forall k \in K, \forall n \in N_k, \forall m \in M_k$

Here discharges $u_{is}(k, n)$, $u_{js}(k, n)$ and spillages $y_i(k, n)$, $y_j(k, n)$ are already known parameters calculated in the base case planning (blocks 3-4) and other quantities are variable. The last four rows in (23) include the effect on the hydro reservoir content from the hydro power production reduction and from the disposal of stored water, in the local station and the stations directly upstream. The hydro power production reduction $\Delta P_{is}(k, n)$ and upward and downward adjustments for the regulating market, $P_{is}^{up}(k, n, m)$ and $P_{is}^d(k, n, m)$ are in MW. However the reservoir content in the hydrological constraints is expressed in hour equivalents (HE). Therefore $\Delta P_{is}(k, n)$, $P_{is}^{up}(k, n, m)$ and $P_{is}^d(k, n, m)$ are converted to the corresponding water discharge in HE, using the production equivalent μ_{is} of the respective HPP production function in Fig. 3.

For the rest of the current week included in the planning, that is for $K_{last}^{day} < k \leq K_{last}$, deterministic prices and wind power production are assumed, where K_{last} is the last hour in the planning period $K_{last} \subset K$. However, the decision variables in the last hour of the planning day differ depending on the power market price and wind power production scenarios. Thus the decision variables for the rest of the week are also stochastic. The scenario tree of the decision process from the last hour of the planning day till the end of the current week will consist of parallel branches, each emanating from one scenario dependent state in the last hour of the planning day.

Fig. 5. Schematic structure of the scenario tree for stochastic decision process

The adjustment bids to the regulating market are not considered for that period, as the average wind power production is assumed for the rest of the current week included in the planning.

$$P_{is}^{up}(k, n, m) = 0, P_{is}^d(k, n, m) = 0, \forall k > K_{last}^{day} \quad (24)$$

In order to formulate the transmission constraints, let us first consider the situation where only planning for the spot market is done, and the production plan, once submitted to the spot market, could not be changed during the day. This means that the solution of the stochastic optimization problem should satisfy all constraints at any wind power production scenario, the so called "fat solution" [8].

In the coordinated planning, the planned hydro power production at stations I_c should only be reduced during the

hours when congestion on the lines is expected as expressed in equation (13) in order to allow wind power production with lower or nil energy curtailment:

$$\sum_{i \in I_c} \sum_{s \in S_i} \Delta P_{is}(k, n) \leq \sum_{i \in I_c} \sum_{s \in S_i} \mu_{is} u_{is}(k, n) + \bar{P}_w(k, m) - D(k) - \bar{P}_{12}, \forall k, n, m \in K^c(n, m). \quad (25)$$

Constraint (25) states that stored wind energy should be less than or equal to potential wind energy curtailment during the congestion situation. Here for each hour k the minimal wind power production scenario determines the solution. The excess wind power would be curtailed in the real time operation in order to meet the transmission constraint.

Conversely, during the hours when no congestion on the lines is expected as expressed in equation (14), additional hydro power production should not exceed the transmission capacity margin:

$$\sum_{i \in I} \sum_{s \in S_i} \Delta u_{is}(k, n) \mu_{is} \leq \bar{P}_{12} + D(k) - \sum_{i \in I} \sum_{s \in S_i} \mu_{is} u_{is}(k, n) - \bar{P}_w^n(k, m), \forall k, n, m \in K^{nc}(n, m) \quad (26)$$

In this constraint for each hour k the maximal wind power production scenario determines the solution and this corresponds to reserving higher transmission capacity for the wind, when no congestion is expected in the transmission line.

Obviously the constraints (25) and (26) would lead to higher wind energy curtailments on the one hand and less intensive utilization of the transmission capacity on the other.

Now let us assume that after the outcome of wind power production $\bar{P}_w(k, m^*)$ becomes known, the violation of transmission constraints (25) and (26) can be compensated by a respective decrease or increase of hydro power production. These hydro power production adjustments are assumed to be traded on the regulating market shortly before the operating hour. The transmission constraints (25) and (26) should then be rewritten as follows:

$$\sum_{i \in I_c} \sum_{s \in S_i} \Delta P_{is}(k, n) + P_{is}^d(k, n, m) \leq \sum_{i \in I_c} \sum_{s \in S_i} \mu_{is} u_{is}(k, n) + \bar{P}_w(k, m) - D(k) - \bar{P}_{12}, \quad (27)$$

$$\sum_{i \in I_c} \sum_{s \in S_i} \Delta u_{is}(k, n) \mu_{is} + P_{is}^{up}(k, n, m) \leq \bar{P}_{12} + D(k) - \sum_{i \in I} \sum_{s \in S_i} \mu_{is} u_{is}(k, n) - \bar{P}_w(k, n, m), \quad (28)$$

where $P_{is}^{up}(k, n, m)$ and $P_{is}^d(k, n, m)$ are recourse variables corresponding to upward and downward power production adjustments at power plant i , at hour k , at node combination (n, m) .

If no congestion on the lines is expected as described in equation (14), no additional energy is stored in hydro

reservoirs of the I_c stations:

$$\sum_{i \in I_c} \sum_{s \in S_i} \Delta P_{is}(k, n) + P_{is}^d(k, n, m) = 0, \quad \forall k, n, m \in K^{nc}(n, m) \quad (29)$$

If congestion on the transmission lines is expected as described in equation (13), there should be no additional hydropower production in the I_c stations, that is:

$$\sum_{i \in I_c} \sum_{s \in S_i} \Delta u_{is}(k, n) \mu_{is} + P_{is}^{up}(k, n, m) = 0, \quad \forall k, n, m \in K^c(n, m). \quad (30)$$

Average wind power production is assumed from the end of the planning day until the rest of the week, instead of the wind power production scenarios in Fig. 4.

There are also reservoir content limitations, similar to those in the base case planning (5):

$$0 \leq x_i(k, n, m) \leq \bar{x}_i, \quad \forall i \in I, \quad \forall k \in K, \quad \forall n \in N_k, m \in M_k \quad (31)$$

The initial reservoir content is assumed known:

$$x_i(0, n, m) = x_i^o, \quad \forall n \in N_0, m \in M_0. \quad (32)$$

The reservoir content at the end of the planning period is fixed in accordance with mid-term production planning:

$$x_i(K_{last}, n, m) = x_i^{last}, \quad \forall n \in N_{K_{last}}, m \in M_{K_{last}}. \quad (33)$$

The decrease of discharge should not exceed planned discharge $u_{is}(k, n)$ according to the base case planning. Also the water discharge should always be within the limits set by technical and environmental constraints, that is:

$$\Delta P_{is}(k, n) + P_{is}^d(k, n, m) \leq u_{is}(k, n) \mu_{is}, \quad \forall i \in I, \quad \forall s \in S_i, \quad \forall k \in K, \quad \forall n \in N_k, m \in M_k, \quad (34)$$

$$\Delta u_{is}(k, n) + \frac{P_{is}^{up}(k, n, m)}{\mu_{is}} \leq \bar{u}_{is} - u_{is}(k, n), \quad \forall i \in I, \quad \forall s \in S_i, \quad \forall k \in K, \quad \forall n \in N_k, m \in M_k. \quad (35)$$

The new variables, introduced in the re-planning part, should be positive:

$$\Delta u_{is}(k, n), \Delta P_{is}(k, n), P_{is}^d(k, n, m), P_{is}^{up}(k, n, m) \geq 0, \quad \forall i \in I, \quad \forall s \in S_i, \quad \forall k \in K, \quad \forall n \in N_k, m \in M_k. \quad (36)$$

Additional water spillage due to energy storage in hydro reservoirs is not allowed in the re-planning part of the planning algorithm. It is meaningless to integrate wind power if it results in energy spillage at other power plants.

Summarizing, the re-planning program is formulated as follows: maximize the objective function (16) subject to the constraints (17)-(24) and (27)-(36).

H. GAMS/MATLAB

The developed planning model has been implemented in General Algebraic Modeling System (GAMS) [21], which is specifically designed for modeling linear, nonlinear, and mixed integer optimization problems. Stochastic wind power

production and power market prices are represented by discrete scenarios, the large scale deterministic equivalent of the stochastic problem can be formulated. The scenario reduction algorithms described in [10] have been contained in the library SCENRED since 2002, however, as scenario bundling is not yet included in SCENRED, scenario reduction with bundling is coded in MATLAB. The GAMS/MATLAB interface is used for data exchange between two programmes [22]. The GAMS solver CPLEX is used to solve the large-scale linear optimization problem.

III. CASE STUDY

The developed planning algorithm is tested in a case study. The case study is based on the actual case where a Swedish company is interested in building a WF in the mountainous area in northern Sweden near the Norwegian border. The capacity of the planned wind power installation is 30 to 90 MW. The wind conditions are very good in this area but the transmission capacity of the lines is limited to 350 MW. On the Swedish side of the border 250 MW is reserved for hydro power production from five HPP stations on the Ume river and the other 100 MW is reserved for power exchange with Norway. Although the power line is not always utilized to 100%, the connection of the WF has been rejected.

In the case study nine stations of the Ume river shown in Fig. 6 are modelled and production of the five upper stations with a total installed capacity of 250 MW are assumed to be coordinated with a 60 MW wind farm. These stations and the wind farm share 250 MW of the transmission capacity. In the case study the uncoordinated hydro power planning and the coordinated planning with wind power is done successively day by day for one week. The results are then compared.

Fig. 6. Studied HPP system of Ume river.

The following assumptions and data are used:

- It is assumed that there is no local load in the area with congestion problem.
- Hourly inflow to the hydro reservoir system of Ume river from 2001 is used as an input data.
- Reservoir contents of the HPP system at the end of each week are fixed to the corresponding values from 2001.
- The actual wind speeds from the studied site in 2001 are used as the wind speed forecast because wind speed forecast data were not available.

- Forecast error is modelled as described in Section II-C. Forecast error data from Eastern Denmark in 2003 are used to calculate parameters for the forecast error time series.
- 1000 forecast error scenarios are first generated by sampling from ARMA model, then the initial scenario fan is reduced by 20% with regard to the original scenario tree, [10], and then additionally by 1% per time step in the scenario reduction and bundling process, see Section II-F.
- The spot market price scenarios are generated by sampling from historical prices for 82 first week days in 2004. This means that 82 price scenarios, covering 24 hours, were defined. For each spot price scenario, one upward and one downward regulation power price scenario were generated by sampling from the ARIMA model [20]. Each scenario thereby consists of three components as in (12). Hence, a scenario tree consisting of 82 scenarios were used as input to the optimization. The scenario tree is then reduced by 20% [10].
- The HPP system is assumed to operate according to the production plan.
- The power curve of the 2 MW wind turbine Vestas 80 is used to convert wind speeds to power. The wind farm smoothing effect is not considered.

Fig. 7. Hydro power production as a result of the uncoordinated planning and as a result of the coordinated planning for the stations 1-5 of the studied HPP system

Fig. 7 shows hydro power production for the first five stations of the studied HPP system as a result of the uncoordinated and the coordinated planning. The results are shown for the first week in January.

According to the uncoordinated case, during some hours the hydro power production from the first five HPPs is as high as the available transmission capacity. In the coordinated case, hydro power production at these stations is reduced to free some transmission capacity for expected wind power. Reservoir content of the HPP stations at the end of the week is fixed in accordance with data from 2001. Therefore the effect of coordination does not extend beyond that week.

In accordance with the assumption that the hydro power system has priority to use the transmission capacity from the

studied area, wind power production is calculated considering the transmission margin left after hydro power production has been scheduled.

Fig. 8 shows wind power production for the cases with and without coordination. Potential wind power production is also shown in this figure. Wind energy curtailment is reduced during the studied week from 1414 MWh in the uncoordinated case to 372 MWh in the coordinated case, which is by almost 75%. Some wind energy curtailment still prevails due to the technical limitations of the considered HPP system.

Fig. 8. Wind power production with and without coordination, and potential wind power production.

Fig. 9 shows the power transmission for the studied week. In the coordinated case power transmission is higher than in the case when wind power and hydro power are not coordinated. Available transmission capacity is also used more intensively in the coordinated case.

Fig. 9. Power transmission with and without coordination.

The income of nine HPP stations of Ume river is calculated using actual power prices and wind power production. For the

studied week the income is 1.6×10^7 SEK in the uncoordinated case and 1.9×10^7 SEK in case when hydro power planning is coordinated with WF.

For the studied week, the income of the wind farm owner in the uncoordinated case is 8.3×10^5 SEK and, in the case with coordination, 8.6×10^5 SEK. The difference is not high due to the fact that the maximum price for the coordination service in (15) is applied in this case study. In practice this price should be based on agreement between the hydro power and the wind power utility and would be less than the maximum value defined by (15).

IV. CONCLUSIONS AND FUTURE WORK

This paper has presented the developed short term hydro power planning algorithm in coordination with wind power in areas with congestion problems, taking account of the uncertainty of wind power forecasts and power market prices.

The developed planning algorithm was tested in the case study, which has shown that coordination of wind power and hydro power can be beneficial for both the wind power utility and the hydro power utility. The coordination greatly decreases wind energy curtailments and also leads to a more efficient utilization of the existing transmission lines, without any negative economical impact on the hydro power utility or wind power utility.

The following improvements of the planning model need to be addressed in the future:

- The case study was applied to a period in the past. It was thus assumed that the outcomes of all stochastic variables were known when the planning for the next day was being conducted. In reality planning the realization of some stochastic variables for the current day would still be unknown. This problem would need to be dealt with in future work.
- A longer case study would need to be conducted in the future.
- The impact of the coordination on start-ups of the hydro power plants would need to be investigated.

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