Strategies for local coordination between wind and hydropower

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Summary

The European Union has set a binding target of 20% of the energy demand to be covered by wind and other renewable sources by 2020. In order to achieve this target, more than one-third of the electrical energy should be produced by the renewables [1]. Wind power is one of the most efficient alternatives and thus wind farms expected to supply 12 – 14% of the total electricity consumption.

The best conditions for the development of wind farms are in remote, open areas with low population density. The transmission system in such areas might not be dimensioned to accommodate additional large-scale power infeed.

The preceding Vindforsk project "Coordination between wind power and hydro power" has concentrated on the fourth alternative, i.e. using existing conventional hydro power plants with large water reservoirs situated in the same area for storage of excess wind energy during the periods with insufficient transmission capacity. There was however room for further improvement of the short term hydro power production planning method coordinated with wind power that was developed in the very final stage of the aforementioned project. The continuation project "Strategies for local coordination between wind power and hydro power" was thus formulated to proceed with the research in this area.

This project started from a comprehensive review of the existing work, providing detailed classification of methods being used and analysis of the results. The project then concentrated on the further development of short term hydro power production method in coordination with wind power from the previous Vindforsk project. The main finding are:

- Wind energy curtailments are reduced by almost 75%;
- Available transmission capacity is used more intensively;
• For the studied week the income of the HPP system is increased by 15.8%.

• For the studied week, the income of the wind farm owner is 3.5% higher. The difference is not high due to the fact that the maximum price for the coordination service is applied in this case study.

The wind power utility does not profit much from the coordination compared to the uncoordinated case. This conclusion led to the development of the alternative coordination strategy presented in the next subsection.

This strategy offers a new fair and transparent method, based on Shapley value, for splitting the extra value caused by a coordinated bidding and operation strategy. In this new coordination scheme flexibility of hydro power system is used here for two purposes: to store excess wind energy during congestion on the transmission line and to balance wind power production variations. For the same case study as the previous coordination strategy an increase of profit of 11% is achieved for wind producer and 1.8% for the hydro producer if they coordinate their planning and bidding comparing to their uncoordinated operation. These figures already include imbalance costs of wind farm producer.

Coordination of wind power and hydro power is an alternative to wind energy curtailments. The energy to be curtailed need to be carefully estimated. This will also have an impact on the amount of hydro regulation needed. Smaller reservoirs might prove to be sufficient for coordination as a result. In the final stage of the project some attention was devoted to more detailed estimation of wind farm power production considering wake effect and availability of the wind turbines. We could conclude that the most detailed estimation of wind energy curtailment costs differs from the least detailed figure by almost 12% (for the particular case study). Therefore we can conclude that if wind-hydro coordination is employed potentially about 12% less wind energy would need to be stored in hydro reservoirs if wind energy yield is estimated in more detail. If electrical losses within the WF and in the cable connecting WF to the grid are included as well as availability of the cables the estimated figures could be reduced even further.
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1 Background

During the last two decades, the increase in electricity demand and environmental concern resulted in a fast growth of power production from renewable sources. The European Union has set a binding target of 20% of the energy demand to be covered by wind and other renewable sources by 2020. In order to achieve this target, more than one-third of the electrical energy should be produced by the renewables [1]. Wind power is one of the most efficient alternatives and thus wind farms expected to supply 12–14% of the total electricity consumption. Attractive features of a wind production, similarly to other renewables, are: environmental friendliness - particularly negligible emissions and low production costs, in many countries supported by subsidies or infeed tariffs and regulations.

The best conditions for the development of wind farms are in remote, open areas with low population density. The transmission system in such areas might not be dimensioned to accommodate additional large-scale power infeed. Furthermore a part of the existing transmission capacity might already be reserved for conventional power plants situated in the same area.

Insufficient export capability problem would emerge for any type of new generation, planned in similar conditions, although wind power has some special features that should be considered when solving this problem. Wind power is a variable power output technology, which cannot be easily predicted and controlled. The wind farm full load hours are only 2000-4000 hours per year.

In the preceding projects "Wind power in regions with limited export capability" and "Coordination between wind power and hydro power" funded by Vindforsk (reported in Doctoral dissertation [2]) four alternatives for large-scale wind power integration in power systems with transmission bottlenecks were studied, Figure 1.

![Wind power in power systems with transmission bottlenecks](image)

Figure 1: Alternatives for large-scale wind power integration in power systems with transmission bottlenecks
The latter project "Coordination between wind power and hydro power" has concentrated on the fourth alternative, i.e. using existing conventional hydro power plants with large water reservoirs situated in the same area for storage of excess wind energy during the periods with insufficient transmission capacity. In the final part of [2] evaluation method of wind energy storage possibility in hydro reservoirs has been developed along with a short term hydro power production planning method, considering coordination with wind power. The results have proven that coordination between wind power and hydro power can be mutually beneficial for both power producers and allow more wind power to be integrated in areas with limited export capabilities. Coordination also leads to more intensive utilization of the existing transmission capacity and allows to avoid or postpone costly and time consuming transmission system reinforcements.

There was however room for further improvement of the short term hydro power production planning method coordinated with wind power that was developed in the very final stage of the aforementioned project. The continuation project "Strategies for local coordination between wind power and hydro power" was thus formulated to proceed with the research in this area.

At the very beginning of the preceding project "Coordination between wind power and hydro power" very little was done in this area of research, but the interest for wind/hydro alternative has grown over the last years. We have therefore started this project from a comprehensive review of the existing work, providing detailed classification of methods being used and analysis of the results. The project then concentrated on the further development of short term hydro power production method in coordination with wind power from [2]; alternative coordination strategy is also suggested and the short term production planning method for this strategy was developed. In the final stage of the project some attention was devoted to more detailed estimation of wind farm power production considering wake effect and availability of the wind turbines.

As this was a research project not all initial goals could have been addressed, the project concentrated on the subjects that were of higher interest/importance.

The results of the project were summarized in 4 research papers (given in logical order, rather than chronological):

- *On the Coordination of Wind and Hydro Power*, presented at the 7th International Workshop on Large Scale Integration of Wind Power, Madrid, May 2008

- *Hydro Power Planing Coordinated with Wind Power in Areas with*

- Sharing of Profit from Coordinated Planning and Bidding of Hydro and Wind Power, submitted for publication to IEEE Transactions on Power Systems, April 2009 (currently, in the second review round)

- Effect of wake consideration on estimated cost of wind energy curtailments, accepted for oral presentation at 8th International Workshop on Large Scale Integration of Wind Power, Bremen, October 2009.

The report is structured as follows. We first provide a brief summary on each of the aforementioned papers without going into modeling details. The main contributions as well as key findings are highlighted. The conclusions and recommendations from the whole project are summarized by the end of the report. The papers are attached in the Appendix and can be referred to for modeling details and in-depth results.

2 Coordination of wind and hydropower, overview of the existing work

This section summarizes the paper "On the Coordination of Wind and Hydro Power", presented at the 7th International Workshop on Large Scale Integration of Wind Power, Madrid, May 2008.

The interest for coordination of wind power and hydro power has increased during the last 5-7 years. It is studied by utilities (e.g. Vattenfall, Skelefteå Kraft in Sweden, Hydro-Quebec in Canada) as well as by research organizations (e.g. SINTEF in Norway, NTNU in Norway and VTT in Finland, INESC-Porto in Portugal, Universidad Carlos III de Madrid in Spain, Ecole des Mines de Paris in France, NTUA in Greece, etc.). However the purposes for which coordination is applied, the methods and the obtained results greatly differ. The in-depth review of these studies is thus necessary in order to analyze applied methodologies and to draw common conclusions the on the benefits and limitations of wind-hydro coordination as well as to point out the areas in which further research might be required. Twelve studies from Sweden (3), Norway (3), Portugal (1), Germany (1), Spain (1), France

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1 Vindforsk project, Samkörning av vindkraft och vattenkraft i Skellefteälven
Greece (1), Canada (1) that were considered of the most relevance were analyzed in this project.

The current research on wind-hydro coordination can be divided into two main categories:

1. "Pre-feasibility" studies, where the possibility of coordination between wind power and hydro power is evaluated for different purposes, using available tools.

2. Planning methods, that is development of new planning methods for hydro power utility in coordination with wind power.

The coordination of wind power and hydro power has been approached from quite different perspectives. The research can thus be further divided into three focus areas.

a. Coordination of a wind farm (WF) and existing conventional hydro power plants (HPPs) with reservoirs for common profit maximization. Here existing planning tools for hydro power production planning (usually mid-term planning with weekly resolution) are used. This focus area is mainly directed towards assisting hydro power utilities considering investments in wind power.

b. Coordination of wind power and existing conventional HPPs with reservoirs in order to use available transmission capacity more effectively and thus allow higher wind power penetration with lower or nil wind energy curtailments. In this focus area both pre-feasibility studies and planning methods from the above categorization are presented. Remarkably pre-feasibility studies mainly assume common ownership of WF and HPP, whereas planning methods also consider separate ownership.

c. Coordination of WF and pumped storage HPP (or generic storage) for minimization of imbalance costs due to wind power production forecast error. In this focus area only the planning methods are presented.

d. Coordination of wind and pumped storage HPP for a firm or a piecewise firm power production. In this focus area both pre-feasibility studies and planning methods are presented.

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2IEA Annex 24, Integration of Wind and Hydro Power systems provides comprehensive bibliography on wind power integration and wind/hydro coordination containing more than 300 items.
An interesting observation is that there are no studies, where conventional hydro power is used for balancing of wind power forecast error. One reason for this is that in most of the studies in balancing focus area (c.) a new pumped storage owned by the same company as a WF is assumed. Whereas a general case with conventional HPP usually means separate ownership and thus the imbalances of wind power producer due to wind power forecast error will be addressed within a market framework.

![Diagram](image)

Figure 2: Classification of the present research.

The focus areas naturally intersect with each other, Figure 2. Providing firm power from the wind-hydro power plant (d.) can be seen as a subset of the balancing focus area (c.). Transmission limits (b.) sometimes present as the constraints in the problems where balancing of wind power forecast error (c.) or profit maximization of hydro power utility (a.) is a main concern. Remarkably though in the focus area where wind and hydro power production is optimized for the common profit maximization (a.) only midterm planning (weekly time resolution) is considered and thus balancing problem (c.) is beyond the modeling scope.

The paper "On the Coordination of Wind and Hydro Power", attached in the Appendix, provides more detail on each of the reviewed studies bellow the main conclusions from each focus area are summarized bellow by the focus areas. It should however be pointed out that due to the intersections of the focus areas some conclusions and recommendations from one focus area might even be applicable in the other focus areas. To provide better overview the comparable results from the reviewed studies are summarized in Table 2 (focus areas a. and b.) and in Table 2 (focus areas c. and d.)
Table 1: Overview of the main results in focus areas a. and b.

<table>
<thead>
<tr>
<th>Reference</th>
<th>[8]</th>
<th>[9]</th>
<th>[5]</th>
<th>[10]</th>
<th>[17]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total export capacity</td>
<td>430</td>
<td>950</td>
<td>6%</td>
<td>1700</td>
<td>950</td>
</tr>
<tr>
<td>Wind capacity with conservative assump.</td>
<td>115</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Wind capacity with coord.</td>
<td>600</td>
<td>30</td>
<td>25 and 36</td>
<td>1000</td>
<td>60</td>
</tr>
<tr>
<td>Curtailm. without coord. in % of unconstr. prod.</td>
<td>5%</td>
<td>1.5-4.5-7.3%</td>
<td>11% and 20%</td>
<td>36%</td>
<td></td>
</tr>
<tr>
<td>Curtailments with coord. in % of unconstr. prod.</td>
<td>2%</td>
<td>0-1.5%</td>
<td>14% or 23%</td>
<td>8%</td>
<td></td>
</tr>
<tr>
<td>WF revenue in % of uncoord.</td>
<td>127%</td>
<td>20%</td>
<td>9%-4%</td>
<td>103%</td>
<td></td>
</tr>
<tr>
<td>HPP revenue in % of uncoord.</td>
<td>100%-102%*</td>
<td>137%</td>
<td>115%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Effect of water spillage</td>
<td>almost none</td>
<td>↓ 19%</td>
<td>not allowed</td>
<td>↓ 0.7%-15%</td>
<td>not allowed</td>
</tr>
</tbody>
</table>

* Common revenue of wind-hydro utility

Table 2: Overview of the results in the focus areas d. and c.

<table>
<thead>
<tr>
<th>Reference</th>
<th>[14]</th>
<th>[15]</th>
<th>[12]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Storage size in hours of full WF operation</td>
<td>5; 10; 15</td>
<td>2</td>
<td></td>
</tr>
<tr>
<td>Neg. imb. pr. in relation to spot pr.</td>
<td>1.25</td>
<td>1.5</td>
<td>1.25</td>
</tr>
<tr>
<td>Pos. imb. pr. in relation to spot pr.</td>
<td>1.1</td>
<td>1.5</td>
<td>1.25</td>
</tr>
<tr>
<td>Wind energy curtailment without storage</td>
<td>16%</td>
<td>5%-16%</td>
<td>not constr.</td>
</tr>
<tr>
<td>Revenue savings with storage vs without</td>
<td>8%</td>
<td>12%-22%</td>
<td>30%</td>
</tr>
</tbody>
</table>

2.1 Profit maximization

- The studies where optimization in applied have shown that water spillage at HPPs is decreases compared to the uncoordinated operation of WFs and HPPs, [10], [4].

- Coordination is more advantageous in the areas where wind power production is strongly correlated with electricity demand [10], [8] and [4].

2.2 Transmission bottlenecks

- Coordination leads to reduction of wind energy curtailments in areas with transmission bottlenecks, Figure 3.

- Spreading wind farms over the larger geographical area and considering smoothing effect allows higher wind power penetration in areas with limited export capacity, [8].

- Coordination of WF and HPPs on both the spot and the intra-day markets adds flexibility to the wind-hydro system and leads to further
Figure 3: Wind energy curtailments in coordinated and uncoordinated cases in % of unconstrained wind energy production.

decrease of wind energy curtailments and more optimal operation of the involved HPPs.

- Coordination leads to increase number of regulations at the involved HPPs, especially if the previous conclusion is taken into account. Increased number of regulations might lead to efficiency reduction and increased maintenance costs for the HPP, [5].

- Costs associated with regulations of the HPP should be included in the optimization. Thus a trade off will be made between additional regulations and increased revenue from coordination.

- Coordination might lead to the operation off the optimal efficiency points. The extent of this effect however depends on the hydro turbine type, [5].

- Optimization should be applied for the coordinated production planning. Hence a trade off will be made between negative impact on the efficiency and overall revenue improvement.

- During coordination water is stored in hydro reservoirs this leads to increased water head and hence increased HPP efficiency. This effect is only shortly mentioned in [4] and needs to be studied further.
• Consideration in the daily planning of wind power production in the coming days contributes to more optimal management of reservoirs and higher benefits from the coordination, [17]. This conclusion is also confirmed in the research within balancing focus area, e.g. [15].

2.3 Balancing and firm power production

• Any balancing strategy is more beneficial than none.

• It is necessary to include storage costs into the problems or in case where existing storage is used for coordination the ownership question should be addressed in order to have more realistic results.

• Value of better forecasting depends on the difference between imbalance prices and spot price.

• The studies in this focus area might benefit from using the probabilistic wind power production forecast instead of point-forecasts.

• Absence of transmission constraints in the problem allows smaller storage.

• A hybrid system can benefit if the wind conditions during the coming days are anticipated in a daily planning.

3 Short term hydro power production planning coordinated with wind power

This section is based on two papers "Hydro Power Planing Coordinated with Wind Power in Areas with Congestion Problems for Trading on the Spot and Regulating Market" and "Sharing of Profit from Coordinated Planning and Bidding of Hydro and Wind Power". The papers propose two different coordination strategies for wind and hydro power producers as well as short term hydro power production planning methods for those strategies. Coordination strategy developed in "Hydro Power Planing Coordinated with Wind Power in Areas with Congestion Problems for Trading on the Spot and Regulating Market" will be referred as Strategy 1 in further in the text. The strategy developed in "Sharing of Profit from Coordinated Planning and Bidding of Hydro and Wind Power" will be further referred as Strategy 2.
3.1 Strategy 1, payment for coordination service

3.1.1 Overview of the coordination strategy

A hydro power system is assumed to be coordinated with a WF as follows: 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. Energy is then retained in the hydro 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 production 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 production.

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, 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. Depending on the generation capacity of the utility this assumption can be reasonable or not. For example the turn over quantities on the Nordic regulating market are small compared to the Nordic spot market implying that the market price is more sensitive to the behavior of the actors on the regulating market. In order to capture this, the actor performance influence on the price must be modeled.

\(^3\)The core of this method was developed within the preceding Vindforsk project. [2], however since the paper was submitted to the Electric Power Systems Research Journal the method has undergone some modifications following to the valuable comments of the reviewers.

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• 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 (i.e., fair to wind power utility) 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. 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.

Figure 4: Flow chart of the daily hydro power planning algorithm in coordination with wind power
Hydro reservoir content at the end of the week is fixed in accordance with mid-term planning. 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. However, in a discussion with hydro power 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, although it might negatively affect wind energy curtailments.

The planning is performed for each day in accordance with the flow chart in Figure 4.

The objective of the hydro power producer is to maximize the expected income from produced power subject to hydrological constraints, power transmission constraints and technical and environmental limitations of the hydro power system. Wind power production scenarios, price scenarios and transmission line loading are also taken into account.

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.

Note that imbalance costs due wind power production forecast error are not included in the optimization as wind power producer would have to pay them in either case, i.e. with or without coordination. However in Strategy 2 coordination with hydropower is used even to minimize the imbalances of the wind/hydro coalition.

3.1.2 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 Figure 5 are modeled 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 Figure 6. 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.

The main findings are listed below, see "Hydro Power Planing Coordinated with Wind Power in Areas with Congestion Problems for Trading on the Spot and Regulating Market" in the Appendix for modelling details:

- Due to coordination between wind and hydro power wind energy curtailment is reduced during the studied week from 1414 MWh in
the uncoordinated case to 372 MWh in the coordinated case, i.e., by almost 75%. Some wind energy curtailment still prevails due to the technical limitations of the considered HPP system.

- 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.

- For the studied week the income of the HPP system is $1.6 \times 10^6$ EUR in the uncoordinated case and $1.9 \times 10^6$ EUR in case when hydro power planning is coordinated with WF, i.e. 15.8% higher

- For the studied week, the income of the wind farm owner in the uncoordinated case is $8.3 \times 10^4$ EUR and, in the case with coordination, $8.6 \times 10^4$ EUR, i.e. 3.5% higher. The difference is not high due to the fact that the maximum price for the coordination service 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 price assumed in this case study.

In conclusion, the case study, 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. It should be noted however that wind power utility does not profit much from the coordination compared to the uncoordinated case. This conclusion led to the development of the alternative coordination strategy presented in the next subsection.

### 3.2 Strategy 2, coalition

This strategy proposes to coordinate (as far as legislation allows) planning and bidding strategy of the wind and hydro power producers. In many systems, a shared bidding strategy by two or more market participants could be perceived to have cartel agreement elements, not allowed by law. On the other hand, legislation allows merges of power production companies, unless the resulting market share exceeds a certain value. Therefore we make an assumption, that there is a legal construction enabling a coordinated planning and bidding of power producers.
Besides power producers, also TSO may benefit from the coordination of the producers, which would bring a self-regulating effect of producers, which should be actually a desired property of the transmission system operation. Benefit for TSO would be twofold: a minimal need for TSO involvement in the congestion management (in other words no the TSO does not have to initiate any congestion relief actions, as the concerned market participants initiate them themselves) and a high utilization of transmission assets.

A coordinated planning and bidding would yield a benefit on the side of power producers, allowing them to optimize their profits by means of optimal utilization of their production facilities with respect to external conditions (such as in this case transmission restriction) and their technical properties (in this case storage capability of the hydro power plant and low production costs of the wind power plant).

To provide an incentive for producers to coordinate their planning and operation, a scheme for sharing either production costs, or resulting profit has to be applied. Shapley value is one approach to the fair allocation of gains obtained by cooperation among several actors. The setup is as follows: a coalition of actors cooperates, and obtains a certain overall gain from that cooperation. Since some actors may contribute more to the coalition than others, the question arises how to distribute fairly the gains among the actors. Or phrased differently: how important is each actor to the overall operation, and what payoff can they reasonably expect.

This strategy offers a new fair and transparent method, based on Shapley value, for splitting the extra value caused by a coordinated bidding and operation strategy. A new coordination scheme is developed employing stochastic optimization to maximize total profit of the wind-hydro coalition. Additionally the imbalance costs of the coalition are also minimized. In other words flexibility of hydro power system is used here for two purposes: to store excess wind energy during congestion on the transmission line and to balance wind power production variations.

The assumptions for the planning algorithm are the same as in Strategy 1, i.e.

- 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 (i.e., fair to wind power utility) behavior of the hydro power utility is assumed.
3.2.1 Case study

The coordination strategy is applied in the same case study as Strategy 1. The profit of a producer(s) is obtained by summing up revenues and balancing payments, which can be either negative, or positive depending on the type of imbalance. The comparison of profits for the uncoordinated and coordinated cases is summarized in the table 3.

Table 3: Comparison of profits of the individual and coordinated strategies, EUR.

<table>
<thead>
<tr>
<th>Producer</th>
<th>Individual strategies</th>
<th>Coordinated strategy</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydro Power Plant</td>
<td>579 956.0</td>
<td>590 107.95</td>
</tr>
<tr>
<td>Wind Farm</td>
<td>91 332.4</td>
<td>1 014 84.35</td>
</tr>
<tr>
<td>Overall profit</td>
<td>671 288.4</td>
<td>691 592.3</td>
</tr>
</tbody>
</table>

While the allocation of profits among the producers is straightforward in case of the individual strategies, for the coalition we apply Shapley value to profit allocation. For this particular example and the particular set of conditions an increase of profit of 11% is achieved for wind producer and 1.8% for the hydro producer if they coordinate their planning and bidding comparing to their uncoordinated operation.

4 Impact of Wake Effect and WT availability on Wind Energy Curtailment

Wind-hydro coordination was considered as an alternative to wind energy curtailments. The energy to be curtailed need to be carefully estimated. This will also have an impact on the amount of hydro regulation needed. Smaller reservoirs might prove to be sufficient for coordination as a result.

In the paper "The Influence of Wake Effect on Economics or Wind Energy Curtailment", in collaboration with University of Manchester the wake effect model was developed and applied to energy yield estimation of a wind farm. Also availability of wind turbines within a wind farm has been considered.

The estimation method was applied to a case study where a WF is developed in an area with good wind potential and with other available generation and load. Transmission capacity from this area is limited to 70 MW. Throughout a year the power transmission through the aforementioned corridor varies with load. For about 4000 hours per year the loading is less than 55% of total transmission capacity. The wind farm consists of 9
Table 4: Estimated costs of wind energy curtailment in MEUR

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<tr>
<th></th>
<th>Without wake, without avail.</th>
<th>Without wake, with 97% avail.</th>
<th>With wake, without avail.</th>
<th>With wake, with 97% avail.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Per year</td>
<td>0.289</td>
<td>0.281</td>
<td>0.267</td>
<td>0.255</td>
</tr>
<tr>
<td>Cumulative, (over 25 years)</td>
<td>7.225</td>
<td>7.025</td>
<td>6.675</td>
<td>6.375</td>
</tr>
<tr>
<td>Difference compared to reference case (over 25 years)</td>
<td>Reference case</td>
<td>0.200 (-2.8%)</td>
<td>0.550 (-7.6%)</td>
<td>0.85 (-11.8%)</td>
</tr>
</tbody>
</table>

wind turbines and has a rated power of 18 MW. Assuming average price for wind energy curtailment of 6.43 EUR/kWh\(^4\) the cost for energy curtailment is estimated with different level of precision. The results are summarized in the Table 4. We can that the most detailed estimation of wind energy curtailment costs differs from the least detailed figure by almost 12%.

This result can be projected to wind-hydro coordination as follows. As constant price for wind energy curtailment was assumed in this case study, we can conclude that potentially about 12% less wind energy would need to be stored in hydro reservoirs if wind energy yield is estimated in more detail. If electrical losses within the WF and in the cable connecting WF to the grid are included as well as availability of the cables the estimated figures could be reduced even further.

5 Conclusions and recommendations

In the following the main conclusions of this project are summarized and recommendations for wind-hydro coordination provided.

- Coordination leads to substantial reduction of wind energy curtailments in areas with transmission bottlenecks.

- Coordination of WF and HPPs on both the spot and the intra-day markets adds flexibility to the wind-hydro system and leads to further decrease of wind energy curtailments and more optimal operation of the involved HPPs.

- Coordination leads to increase number of regulations at the involved HPPs, especially if the previous conclusion is taken into account. Increased number of regulations might lead to efficiency reduction and

\(^4\)UK energy prices were used here, but the relative results presented in Table 4 are relevant in any case.
increased maintenance costs for the HPP. Costs associated with more frequent regulations of the HPP production should be included in the optimization problem. Thus a trade off will be made between additional regulations and increased revenue from coordination.

- Coordination might lead to the operation off the optimal efficiency points. The extent of this effect however depends on the hydro turbine type. If optimization is applied for the coordinated production planning a trade off will be made between negative impact on the efficiency and overall revenue improvement. Also restricted operation intervals of the HPP can be included as constraints into optimization problem.

- During coordination water is stored in hydro reservoirs this leads to increased water head and hence increased HPP efficiency. To account for this more detailed representation of hydro power production characteristic is needed however the stochastic optimization programs developed here are already quite heavy with regard to computational time. One solution could be to adjust production characteristic from one planning day to another, depending on how much water has been stored in reservoir in the preceding day. This will still disregard intra-day HPP efficiency changes but will introduced an improvement compared to using same efficiency characteristic all the time.

- The results from literature overview and our work has shown that water spillage at HPPs is decreases compared to the uncoordinated operation of WTs and HPPs.

- Consideration in the daily planning of wind power production in the coming days contributes to more optimal management of reservoirs and higher benefits from the coordination. This conclusion is also confirmed by other works analyzed in literature review.

- Spreading wind farms over the larger geographical area and considering smoothing effect allows higher wind power penetration in areas with limited export capacity.

- More detailed estimation of wind energy yield, considering wake effect and WT availability, will lead to less excess wind energy that need to be stored in hydro reservoirs in case of wind-hydro coordination.

- Any balancing strategy for a wind farm is more beneficial than none. The results from Strategy 2 show that if coalition is formed by wind and hydro power producers, hydro power can be used to even out
wind power production imbalances. The profit of each player in the coalition is still higher than in case of individual operation, although no additional payment for balancing service was assumed in the modeling.

References


[2]


ty for coordination of wind power and hydro power has increased during the last 5-7 years. It is studied by utilities (e.g. Vattenfall [1], Skelefteå Kraft [3] in Sweden, Hydro-Quebec [2] in Canada) as well as by research organizations (e.g. SINTEF in Norway [4], [5], [6], NTNU in Norway and VTT in Finland [8], [9], INESC-Porto in Portugal [13], Universidad Carlos III de Madrid in Spain, [10], Ecole des Mines de Paris in France [11], NTUA in Greece [16], etc.).

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However the purposes for which coordination is applied, the methods and the obtained results greatly differ. The in-depth review of these studies is thus necessary in order to analyze applied methodologies and to draw common conclusions the on the benefits and limitations of wind-hydro coordination as well as to point out the areas in which further research might be required.

The paper is organized as follows. The classification of the present research is introduced in Section II. Then Section III presents the in-depth description of the analyzed studies and discusses similarities and differences in each focus area. Section IV summaries common results, conclusions as well as points out the questions for further research in each focus area.

II. CLASSIFICATION OF THE PRESENT RESEARCH

The current research on wind-hydro coordination can be divided into two main categories:

1) "Pre-feasibility" studies, where coordination possibility is evaluated for different purposes, using available tools [8], [9], [1], [4], [5] or developing new evaluation methods [2], [6], [7], [17];

2) Planning methods, that is development of new planning methods for hydro power utility considering coordination with wind power [10], [11], [12], [13], [14], [15].

The coordination of wind power and hydro power has been approached from quite different perspectives. The research can be thus further divided into several focus areas.

a. Coordination of a wind farm (WF) and existing conventional hydro power plants (HPPs) with reservoirs for common profit maximization. Here existing planning tools for hydro power production planning (usually midterm planning with weekly resolution) are used, [9], [8], [2]. This focus area is mainly directed towards assisting hydro power utilities considering investments in wind power.

b. Coordination of wind power and existing conventional HPPs with reservoirs in order to use available transmission capacity more effectively and thus allow higher wind power penetration with lower or nil wind energy curtailments. In this focus area both pre-feasibility studies and planning methods from the above categorization are presented. Remarkably pre-feasibility studies mainly assume common ownership of WF and HPP [5]1, [3], whereas planning methods also consider separate ownership [14], [15].

c. Coordination of WF and pumped storage HPP (or generic storage) for minimization of imbalance costs due to wind power systems or pumped storage hydro power plants, are suitable for this purpose. This is a relatively recent topic of research and it has been approached in several papers from quite different perspectives. This paper is an attempt to summarize the existing research on this subject and to draw some general conclusions on the benefits and the limitations of the coordination between wind and hydro power as well as point out some areas in which further research might be required. Present research is divided into several focus areas. Studies from Norway, Portugal, Spain, Sweden, France, Germany and Canada are analyzed in each focus area and methodologies, results and common conclusions are discussed.

Index Terms—wind power generation, hydro power generation, optimization, power market, forecasting.
power production forecast error. In this focus area planning methods, e.g. [12], [11] are presented.

d. Coordination of wind and pumped storage HPP for a firm or a piecewise firm power production. In this focus area both pre-feasibility studies, e.g. [16], [18], [17] and planning methods [13] are presented.

An interesting observation is that there are no studies, except [10], where conventional hydro power is used for balancing of wind power forecast error. One reason for this is that in most of the studies in balancing focus area (c.) a new pumped storage owned by the same company as a WF is assumed. Whereas a general case with conventional HPP usually means separate ownership and thus the imbalances of wind power producer due to wind power forecast error will be addressed within a market framework.

Figure 1. Classification of the present research.

The focus areas naturally intersect with each other, Figure 1. Thus providing firm power from the wind-hydro power plant (d.) can be seen as a subset of the balancing focus area (c.). Transmission limits (b.) sometimes present as the constraints in the problems where balancing of wind power forecast error (c.) or profit maximization of hydro power utility (a.) is a main concern. Remarkably though in the focus area where wind and hydro power production is optimized for the common profit maximization (a.) only midterm planning (weekly time resolution) is considered and thus balancing problem (c.) is beyond the modeling scope.

III. SUMMARY OF THE REVIEWED STUDIES

The following subsections present the in-depth description of the recent research in each of the aforementioned focus areas. Similarities and differences in modeling methods, level of details and obtained results are also discussed. Table I comprises some initial data and methods used in the reviewed studies.

A. Investment possibilities and profit maximization

Table I comprises some initial data and methods used in the reviewed studies in focus areas a. and b.

In [2] the coordination of WF with existing HPPs is considered in generation expansion planning. Two investment possibilities are compared in [2]: a new run-of-the-river hydro power plant versus a new wind farm. Also two cases are

Figure 2. Overview of the system studied in [8]

The research in [8] is a further development of [9] and is directed towards assisting hydro power utilities considering investments in wind power. Figure 2. 300-3000 GWh of wind power is added in Mid-Norway. The complementary characteristics of wind energy and hydro inflow served as motivation for that paper. Wind energy production in Mid-Norway is remarkably well correlated with demand, similar conditions as in [2], whereas the yearly variations of hydro inflow and wind energy seem to be weakly correlated. The main concern is to identify how the increasing amount of studied power production in order to fulfill demand obligations or profit maximization given a spot market price. Existing optimization tool for mid-term hydro power production planning is used in this study. A WF appears to be more attractive option compared to a run-of-the-river HPP. Following reasons are listed to explain this conclusion: in colder regions wind power production is usually correlated with load on a weekly basis while water inflows are more seasonal; no zero wind on a weekly basis, but for water inflow it is quite frequent; wind power option leads improved management of hydro reservoirs (reduced water spillage). Both options lead to increased average water head in the existing hydro reservoirs and thus increase of the efficiency of the respective HPPs.

In [9] the effect of 16 TWh wind power on the Nordic spot market prices is analyzed using EMPS model (Multiarea Power Scheduling) for the Nordic power system [20]. The model was originally developed for hydro production scheduling purposes. Stochastic dynamic programming algorithm is used in EMPS model. After deregulation of the electricity market it also serves as a tool for price forecasting. The EMPS model contains 18 areas comprising Norway, Sweden, Finland and Germany. Time resolution is one week and the hydro inflow data are based on the period 1961-1990 with weekly inflow data for each existing HPP. Wind power is added to the EMPS model as run-of-the-river HPPs with 30 years of wind speed measurements from several meteorological stations used as "water inflow". The avoided costs, i.e. the reduced production costs from various thermal units substituted by wind energy per kWh, were estimated about 7% of the average spot price for 2010 scenario.
wind energy would influence the optimal scheduling of the hydro power production and to identify a mechanism in play. Two cases are compared: wind-hydro production optimized together and then sold on the spot market or wind power is sold directly at spot price, i.e. no coordination. The first case has shown the increased value of wind power compared to the second case ranging from 9% to 4% declining as amount of wind energy increases to 3000 GWh. The analysis made in the paper suggests that the added value of wind energy can be explained by reduction of water spillage.

### B. Transmission bottlenecks

In [4] and [5] wind energy storage in hydro reservoirs is considered in connection with bottleneck problems in the network. The paper shows to what extent automatic generation control of WF and existing conventional HPPs for avoiding line overloading may influence the annual energy output of each of these production sources. Ref. [6] offers further in-depth evaluation of that coordination possibility, Figure 3.

![Figure 3. Overview of the system studied in [6]](image)

The coordinated operation the existing HPPs and several geographically spread WFs 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. Scheduled hydro generation and spot market prices are obtained from the EMPS model and then hourly data series are synthesized. The results of the case study show that considering wind and hydro characteristics even without coordination up to 600 MW of wind power can be developed in the studied area with only 5% of wind energy curtailments, compared to 115 MW in conservative approach. (WF capacity = Export capacity - HPP capacity + Minimal local load). With wind-hydro coordination wind energy curtailments are reduced to 2%. The benefits of taking smoothing effect from geographical spreading into account are also shown by simulating 30 years of operation of three 200 MW WF vs one 600 MW WF. There case study with one WF leads to 4% (annual average) wind energy curtailments if coordinated with HPPs, i.e. twice as much as in 3x200MW case. A common revenue is calculated as sum of produced energy (wind and hydro) multiplied by a spot price (interpolated from EMPS results). With up 400 MW of wind power in the area, there is no reduction in total income of wind and hydro producers in case of coordinated operation compared to unconstrained case, i.e. without transmission limitations. With 600 MW wind power the total income of wind and hydro producer reduction is 1% (annual average) in coordinated case and income reduction of wind power producer is 3% (annual average) in uncoordinated case both compared to unconstrained case. It seems that the income reduction is mainly due to remaining wind energy curtailments, though this is not clearly stated in the paper. The above results are achieved for a hydro power system with relatively small reservoir and high share (37%) of non-storable water inflow. Similarly to [2] and [8] this study also concludes that due to strong correlation between wind power production and power consumption in winter more wind power can be installed in areas with transmission bottlenecks than results form the conservative estimation. Though in the contrast to [2] and [8] in this study coordination leads to small additional water spillage. This can be explained by the fact that simulation was used in this study not optimal wind and hydro production planning as in [2] and [8].

In [7] several strategies are suggested assuming separate ownership of wind power and hydro power in area with transmission bottlenecks:

1) no coordination,
2) coordination maximizing common revenue of the wind power and hydro power producers (e.g. same owner),
3) coordination maximizing hydro producers revenue,
4) coordination minimizing wind energy curtailments.

The coordination strategies are then evaluated using historical data of the hydro power system operation and wind speed measurements from the studied site. The coordination strategies are then evaluated using one year historical data of water inflow and wind speed measurements from the studied site. The evaluation method is rather close to [4], although there are some differences in modeling and input data. Also in [4] only strategy maximizing wind power penetration is evaluated (similar to strategy 4 above). Conservative approach allows 0 MW wind power in the studied area, 30-90 MW were tested in [7]. The results has shown that considering hydro power production characteristic it is possible to install 30 MW of wind power with small wind energy curtailments even without coordination, however any coordination strategy is better than none. It can be concluded that strategy 2 should be applied in case if wind farm and HPPs are owned by the same company, strategy 3 should be applied in case of separate ownership, strategy 4 shows what is physically possible and is comparable to [4], [5] and [6], but it is difficult to introduce it within the electricity market framework.

In [14] a daily planning algorithm is developed for a multi-reservoir hydro power system coordinated with a wind farm. The planning algorithm assumes coordination strategy 3 from [7]. Wind power and hydro power are assumed to be owned by different companies. WF and HPP system share the same transmission lines, but hydro power utility has priority to use the transmission capacity\(^3\). 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 developed coordinated planning is to provide the hydro power utility with optimal hourly bids to the day-ahead market (spot market), considering uncertainty of the wind power forecast. Ref. [15] presents further improvement of the coordinated planning algorithm from [14]. The coordinated planning algorithm considers the uncertainty in the wind power forecast as in [14] and also the uncertainty of power market prices. The planning algorithm includes a spot market and a regulating market (intra-day). The optimization problem is formulated as a two-stage stochastic program with recourse. The coordinated planning algorithm is applied in the same case study as in [7], with 60 MW of wind power. As the main purpose of [15] is the development of the planning algorithm not the case study itself, only one week is studied (both planning and operation) with hourly resolution. The result shows that with coordination wind energy curtailments can be reduced by 75% compared to uncoordinated case. Some wind energy curtailments still remain due to the technical limitations of hydro power system. The income of the hydro power utility is increased by 15% because of coordination. The income of wind power producer is increased by 3% compared to the uncoordinated case. The improvement is so small due to the fact that coordination service is assumed to be payed by average yearly spot price. In practice this price should be based on more detailed analysis and agreement between wind and hydro utilities. For comparison, the case study in [14], where only the spot market is included, has shown that for the same week the wind energy curtailments are reduced by 50%. The income of the hydro power utility is increased by 16% because of coordination. The income of wind power producer is increased by 2% compared to the uncoordinated case. This difference can be explained by increased planning uncertainties if participation on the intra-day market is not possible. Similar tendencies can be seen in [10] that is discussed later in this paper.

In case where conventional HPPs are used for coordination with wind power the main concern of the hydro power utility is how it will affect operation, efficiency and lifetime of the hydro power plants. The first step in this direction has been done by SkelefteåKraft (Swedish generation company) in [3]. Coordination of two existing HPPs with large reservoirs with a new WF (25 MW or 36 MW) to be owned by the same company is studied. Simulation is done based on historical hydro power operation data and wind speed measurements. The principle of the simulation is to reduce hydro power production, compared to the case without wind power when there is a congestion on the transmission line. If the reservoir is full either wind energy should be curtailed or water spilled, alternatively, stored hydro energy should be continuously redistributed during the hours without congestion to free some space in the reservoirs. This issue however is not included in simulation, only total amount of the access energy due to the full reservoir and simultaneous congestion on the line is calculated for the whole simulated period. In each simulation it is assumed that only one HPP participates in the coordination. In case with 25 MW of wind power 14% or 23% of excess wind energy (7.8 GWh) cannot be stored in the reservoir of the respective HPP participating in coordination and should be either curtailed or redistributed during the hours without congestion. Efficiency of the HPP station participating in coordination is in average decreased by 1.6% or 0.88% respectively due to HPP production reductions (i.e. operation off the optimal efficiency point). In the study both hydro turbines are Francis turbines but the conclusion of this study is that Kaplan turbines might be better suited for coordination because they have an efficiency curve with wider top which means that power regulations would have less impact on the HPP efficiency. It is mentioned in [2] that, as excess wind energy is retained in hydro reservoir, the reservoir level increases and this leads to the increase of HPP efficiency for the next hours of operation. This effect however is not studied in [3]. The number of regulations at the HPP participating in coordination is increased by 35% or 40% respectively. The increased number of regulations leads to cavitation, that in turn might cause the reduction of the HPP efficiency, erosion and vibrations. This study needs to be continued and impact on the efficiency and the number of regulations needs to be studied within the optimization framework in order to keep these two parameters within desired limits. This will be included in further improvements of the planning algorithm presented in [15].

\(^3\)This is often a case in e.g. Sweden.
C. Balancing wind power variations and firm power production

In the previous focus area the impact from coordination on the involved parties (hydro power and wind power utilities, transmission system operators) is studied. It is not always clear beforehand if the coordination will have positive or negative effect on those actors. In this focus area the storage is assumed to be owned by wind power utility in all considered studies, except [10]. In most of the studies the investment costs of the storage are not considered. Thus, obviously, any balancing strategy is more attractive than none. So the comparison should be done more in terms of coordination methods, level of modeling details and necessary storage size in relation to wind farm size. A brief overview of the reviewed studies in these focus areas is presented in Table II. A wind-hydro studied in [12] is constrained by transmission limit from the studied area, load obligation. It comprises generic storage (simultaneous charging and discharging is not possible) and damp load that used in case if excess wind power cannot be transferred. Wind power is assumed always to be sold on the spot market (zero marginal cost). Schedule is done for the spot market and then deviation between scheduled and actual power production is assumed to be subject to imbalances penalties in operating stage. In reality on the Nordic market, the difference between actual and planned production could lead to higher revenue of the producer depending on the overall power balance in the system. This is not included in the study so imbalances are always penalized. The spot price, regulating price and load forecasts are assumed 100% accurate. Wind speed forecast for each hour of the scheduling period is modeled as random number drawn from the normal distribution with given mean and standard deviation. Forecast uncertainty is not included. Only 24 hours scheduling is performed each time. Storage is assumed to be completely discharged by the end of the scheduling period, thus the wind condition the next day are not accounted for. In the planning phase storage is filled and discharged to maximize the income from trading on the spot market. Dynamic programming is used. In the operating stage storage is used in order to cover the difference between forecasted and actual wind power production. Otherwise this deviations are penalized. Simulation study using the above strategy has been performed for one year (but no seasonal wind speed variation or load variations considered). Different storage parameters are tested. The use of damp load is correlated with storage capacity, i.e. the more capacity the less damp load is used. The annual revenue increases with increasing power and energy capacity of the storage as expected. Investment costs of the storage are however not analyzed. Without transmission constraints the storage can be considerably lower. In order to increase the flexibility of the storage, one should set minimum allowable storage level higher than 0. Utilization factor of the storage decreases with reduced round-trip efficiency of the storage. 10% increase in storage round-trip efficiency provides 3% annual revenue increase. With decreased forecast error annual revenue of the hybrid system increases. The benefit of the accurate forecast depends on the difference between spot price and regulating market price. If there is no storage and wind energy curtailments are allowed, this would lead to 16% energy loss and decrease of revenue by 10% compared to the case with the storage. The difference in annual revenue of the hybrid system and wind+new transmission line is also calculated. And it was concluded that with present costs of storage grid reinforcement is likely to be more attractive option.

In [13] wind and pumped-hydro storage are coordinated. In the contrast to [12] scheduling for 48 hours is performed in order to anticipate wind power production the next day. Then the results of the 24 hours of the planning are used to trade at the spot-market. Two main goals are to improve daily wind farm profit and smooth power production changes due to wind power fluctuations (power output is kept within given limits). Given average values and standard deviations representing wind power forecast, wind power time series scenarios are determined through Monte-Carlo simulations. For each of them a linear optimization problem with hourly resolution is solved to determine daily operating strategy. From a number simulations average, minimum and maximum values of the relevant variables are analyzed. These values are used to represent the proposed operation strategy for the next hours and to evaluate the performance of the solutions. The actual Portuguese wind energy remuneration tariffs (may include an hourly modulation coefficient in order to increase the participation of renewables during peak hours) are used to illustrate economic gains that can be obtained by implementation of such operating strategy. Upper and lower production limitation are applied due to network restrictions and market requirements. In the contrast to [12] where storage charging costs were not included here a cost is assigned to pumping. There is a possibility included in optimization to decrease production limit bellow the given value but at a high cost.

### Table II

<table>
<thead>
<tr>
<th>Reference</th>
<th>Focus area</th>
<th>Means</th>
<th>Ownership</th>
<th>Transm. cap., MW</th>
<th>Local load</th>
<th>Installed wind cap., MW</th>
<th>Hydro power capacity, MW</th>
<th>Storage capacity, GWh</th>
<th>Method</th>
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<tbody>
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<td>21</td>
<td>6</td>
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<td>0</td>
<td></td>
</tr>
</tbody>
</table>

*The investment costs only shortly discussed in [12], when comparing new storage vs new transmission line alternatives.*
In the test case pumped HPP stands for 25% of wind farm capacity. Storage size corresponds to 2h of full operation of the wind farm at nominal power. Several operating strategies are used (concerning reduction of the lower production limit). The yearly average economic gain of wind-hydro system compared to wind only case ranges between 12% and 22.2% for the analyzed test case. According to results the pump is operated during low price periods and during congestion hours, which is as expected. The utilization of the information from the second day forecast leads to non-empty reservoirs at the end of the planning day aiming to optimize the next day operation which is an improvement compared to [12]. Similar representation of future wind conditions is also used in [14], [15]. Different systems sizes are not tested. Much more concern is put on studying different conditions for upper and lower production limits. In the presence of imbalance penalties as in [12], this problem would be solved within the optimization.

In [17] the strategy developed in [13] is adapted for the RWE balancing area (37% of the total wind power in Germany) in German power system and a size of a pumped storage hydro power plant necessary to provide firm power from all wind installations in the area is calculated. In Germany there is fixed feed in tariff for wind power, thus there is currently no incentive for wind power utility to store energy. The incentive lies on the side of the TSO who is a balance responsible. The purpose of this study is to show the potential or the hybrid system from the economic and environmental point of view. Equal target weight factors are assigned in the optimization problem for limiting fluctuations of delivered power, for the level of power delivered to the system and for the cost of pump operation. In [13] certain prices are assigned to each of the above parameters. High and low wind periods are tested. Hourly wind power forecasts were generated by WEPRPOG with its operational multi-scheme ensemble prediction systems (MSEPS). The MSEPS is coupled with wind power prediction module which can provide an objective uncertainty of the power forecast. Existing pumped hydro storage is used as a reference pumped storage facility, Table II. The well balanced and smooth power delivery of the coupled wind-hydro is compared with wind only operation. The reserve capacity from other power stations that would have to be purchased daily to balance wind power is reduced by 78% (week with high wind speeds) and 91.9% (week with low wind speeds). Further increased storage and also different values of target weight factors are tested. The results have shown that further increase of the storage leads to only small improvements and in addition the pumps and hydro turbines and very low utilization times of additional pumped HPPs. The study of different weight factors has shown that it is beneficial to put strong weight on the criterion to deliver constant power output and to have less weight on absolute power output. Pumping is of less importance and can be assigned a smaller weight. These tendencies are confirmed by the results in [13].

In [10] the coordination is applied in order to minimize WF imbalance costs. Thus, the coordination with HPPs (conventional HPPs, but not multi-reservoir systems as in e.g. [15]) is employed only on the intra-day market. Spot market prices and imbalance penalties are treated as deterministic. The transmission constraints are not considered. In the intra-day coordination both forecasting tool SIPREÓLICO, [21], and persistence forecast are used and revenues then compared with the case where perfect forecast is used. Forecast uncertainty is not considered in the optimization, i.e. linear programming is used. Cases with 1 intra-day auction or 6 intra-day auctions are tested. The results have shown that the use of the persistence as the forecasting tool leads to a greater loss of revenue, similar to [12]. In the market with a single auction the time span for the forecast is larger than in a market with several auctions and it carries larger losses. As the case study only includes one day, it is not possible to see some effects of combined operation mentioned in other studies, e.g. better management of the reservoirs. Also there is no compensation for hydro utility as e.g. in [15]. Wind and hydro are assumed to be owned by the same utility and coordinated in order to maximize common revenue. Thus the coordination will take place only in case if WF revenue increase due to coordination is higher than the losses of the HPP. When coordinated operation vs uncoordinated operation are compared the results greatly depend on the relation between imbalance penalties and future water prices (price of using the water in the future compared to using it now). E.g. if the water future price is 60 EUR/MWh the hydro power plant will only cover wind power underproduction completely in case if the penalty is very high (1.75 times the marginal price). Different forecasting accuracies and market hypothesis are tested. The results summarized in numerous tables. E.g. for imbalance price equal 1.25 times the marginal price with minimum forecast accuracy and several intra-day auctions the deviations payed by wind power utility compared to deviations payed by combined utility are 36% higher. Same conclusion as in [12] is obtained, i.e. the higher the difference between an imbalance penalty and a spot price the higher is the value of the forecast accuracy.

In [11] further develops the work started in [12] and [13]. The aim is maximize the common profit of the wind-hydro system while minimizing imbalance risks. The same phases as in [12] are included, i.e. day-ahead market scheduling and daily operation. However both the maximization of the profit on the day-ahead market and minimization of energy imbalance risks are included in the formulation of the optimization problem used for performing the day-ahead schedule of the wind-hydro power plant. The actual imbalance minimization is then achieved in the operation phase. Probabilistic wind power production forecasts are used. Spot price forecasts are obtained through a persistence-type model yielding deterministic forecasts. As the purpose of the optimization is to minimize imbalances, not their costs, hence the imbalance prices are not considered. The possibility to consider the interconnection capacity is included in the model though it is not applied in the case study. In the study, only the hourly wind power forecasts corresponding to each hour of the scheduling horizon are considered, i.e. no anticipation of the wind conditions during the coming days. However some flexibility is added by fixing the storage state at 50% of its capacity at the end of each scheduled day, this is also advised in [12]. Quadratic cost function is used for representing the operation cost of the energy storage. The method is applied in a case study where
21 MW wind farm is coordinated with 40 MWh pumped hydro power plant. In the case study one hourly schedule per day is produced and 365 days are simulated using historical data for the year 2002. The case study demonstrates that it is possible to obtain reductions of the energy imbalances generated by the WF while maintaining the profit of the power producer. The results indicate that the joint operation of wind-hydro plants comprising energy storage may enable the hybrid to be a "well-behaved citizen" from the TSO viewpoint whilst the plant operator still maximizes the generated profits. Different risk sensitivities and different risk perception depths are tested to see how the results vary with such parameters. Only one storage and one round-trip efficiency was considered so far. The work presented in [11] continues and more results and improvements of the represented method are to be expected in the future.

It should be mentioned that there also exist other studies on coordination of wind and hydro power for firm or piecewise firm power output in real time operation. Ref. [18] presents a theoretical study of how wind power can be complemented with conventional hydro power hydro power. In e.g. [19] and [16] pumped storage and wind power are combined for satisfactory operation in autonomous islands in Greek archipelago. These studies are not included in the comparison here, as those usually concern smaller scale, isolated wind-hydro systems and also do not include problems introduced within a framework of the electricity market. These studies however might provide useful clues regarding the storage sizing.

IV. SUMMARY OF RESULTS IN EACH FOCUS AREA

This section summarizes common conclusions and interesting observations of the studies discussed above and also points out the areas in which further research may be required. The conclusions are summarized by the focus areas but it should be pointed out that due to the intersections of the focus areas some conclusions and recommendations from one focus area might even be applicable in the other focus areas. For an overview the comparable results of the case studies discussed above are summarized in Table IV (focus areas a. and b.) and in Table IV-C (focus areas c. and d.)

A. Profit maximization

- The studies where optimization in applied have shown that water spillage at HPPs is decreases compared to the uncoordinated operation of WFs and HPPs, [8], [2].
- Coordination is more advantageous in the areas where wind power production is strongly correlated with electricity demand [8], [6] and [2].

B. Transmission bottlenecks

- Coordination leads to reduction of wind energy curtailments in areas with transmission bottlenecks, Figure 4.
- Spreading wind farms over the larger geographical area and considering smoothing effect allows higher wind power penetration in areas with limited export capacity, [6].
- Coordination of WF and HPPs on both the spot and the intra-day markets adds flexibility to the wind-hydro system and leads to further decrease of wind energy curtailments and more optimal operation of the involved HPPs.
- Coordination leads to increase number of regulations at the involved HPPs, especially if the previous conclusion is taken into account. Increased number of regulations might lead to efficiency reduction and increased maintenance costs for the HPP, [3].
- Costs associated with regulations of the HPP should be included in the optimization. Thus a trade off will be made between additional regulations and increased revenue from coordination.
- Coordination might lead to the operation off the optimal efficiency points. The extent of this effect however depends on the hydro turbine type, [3].
- Optimization should be applied for the coordinated production planning. Hence a trade off will be made between negative impact on the efficiency and overall revenue improvement.
- During coordination water is stored in hydro reservoirs this leads to increased water head and hence increased HPP efficiency. This effect is only shortly mentioned in [2] and needs to be studied further.
- Consideration in the daily planning of wind power production in the coming days contributes to more optimal management of reservoirs and higher benefits from the coordination, [15]. This conclusion is also confirmed in the research within balancing focus area, e.g. [13].

C. Balancing and firm power production

- Any balancing strategy is more beneficial than none.
- It is necessary to include storage costs into the problems or in case where existing storage is used for coordination the ownership question should be addressed in order to have more realistic results.
- Value of better forecasting depends on the difference between imbalance prices and spot price.
<table>
<thead>
<tr>
<th>Reference</th>
<th>[6]</th>
<th>[7]</th>
<th>[8]</th>
<th>[15]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total export capacity</td>
<td>900</td>
<td>250</td>
<td>95</td>
<td>1900</td>
</tr>
<tr>
<td>Wind capacity with conserv. assum.</td>
<td>115</td>
<td>0</td>
<td>0</td>
<td>1900</td>
</tr>
<tr>
<td>Wind capacity with coord.</td>
<td>600</td>
<td>30</td>
<td>25 and 36</td>
<td>1000</td>
</tr>
<tr>
<td>Curtailments without coordination in % of unconstr. prod.</td>
<td>5%</td>
<td>1.5-5.7%</td>
<td>3%</td>
<td>20%</td>
</tr>
<tr>
<td>Curtailments with coord. in % of unconstr. prod.</td>
<td>2%</td>
<td>0.1-5%</td>
<td>14% or 23%</td>
<td>8%</td>
</tr>
<tr>
<td>WF revenue in % of unconcoord.</td>
<td>92%</td>
<td>9%-16%</td>
<td>9%</td>
<td>20%</td>
</tr>
<tr>
<td>HPP revenue in % of unconcoord.</td>
<td>101%-102%*</td>
<td>13%</td>
<td>not allowed</td>
<td>115%</td>
</tr>
<tr>
<td>Effect of water spillage</td>
<td>almost none</td>
<td></td>
<td>19%</td>
<td>not allowed</td>
</tr>
</tbody>
</table>

* Common revenue of wind-hydro utility

<table>
<thead>
<tr>
<th>Reference</th>
<th>[12]</th>
<th>[13]</th>
<th>[10]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Storage size in hours of full WF operation</td>
<td>5, 10, 15</td>
<td>2</td>
<td></td>
</tr>
<tr>
<td>Neg. imb. pr. in relation to spot pr.</td>
<td>1.25</td>
<td>1.5</td>
<td>1.25</td>
</tr>
<tr>
<td>Pos. imb. pr. in relation to spot pr.</td>
<td>1.1</td>
<td>1.5</td>
<td>1.25</td>
</tr>
<tr>
<td>Wind energy curtailment without storage</td>
<td>16%</td>
<td>5%-16%</td>
<td>not constr.</td>
</tr>
<tr>
<td>Revenue savings with storage vs without storage</td>
<td>8%</td>
<td>12%-22%</td>
<td>36%</td>
</tr>
</tbody>
</table>

**References**


**V. Biography**

Julija Matevosyan was born in Riga, Latvia in 1978. She received her B.Sc. degree in Electrical Engineering from Riga Technical University, Latvia, in 1999; M.Sc. and Tech.Lic. and Ph.D. degree in Electrical Engineering from the Royal Institute of Technology, Stockholm, Sweden in 2001, 2003 and 2006 respectively. She is currently a researcher with a main interest in large-scale integration of wind power in areas with limited export capability at the Royal Institute of Technology.
Hydropower planning coordinated with wind power in areas with congestion problems for trading on the spot and the regulating market

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1. 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 located in the same area.

As wind power production depends on wind speed, the full load hours of a wind farm are only 2000–4000 h/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 always 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 or pumped hydro-storage for large-scale wind farms is still expensive, but existing conventional power plants with fast production control capabilities and sufficient storage capacity, for example hydropower plants, could be used instead.

The coordination of wind power and hydropower has been studied earlier in connection with several different problems. In [3] the coordination of wind farms with hydropower plants is considered in generation expansion planning. Two investment possibilities are compared in [3]: a new hydropower plant (HPP) versus a new wind farm (WF). In [4,5] the effect of wind power on the market prices is analyzed. The research in [4,5] is directed towards assisting hydropower 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 assuming separate ownership of wind power and hydropower. The coordination strategies are then evaluated using historical data of the hydropower system operation and wind speed measurements from the studied site. None of these papers, however, treat hydropower production planning for daily operation, considering the coordination with wind power.

In [8] the dynamic programming algorithm is presented for a daily planning of coordinated operation of wind parks and generic energy storage in area with limited export capability. In [9] the optimization problem is formulated for daily production planning of wind park and pumped storage hydropower plant, though transmission bottlenecks are not considered. Also, in [8,9] the storage is owned by the wind power utility, wind power production is assumed to be deterministic and multi-reservoir hydropower systems are not considered. These limitations are overcome in planning algorithm developed in this paper.

One of the most recent publications on coordinated planning of wind and hydropower plants is [10]. In that paper the coordination is applied in order to minimize WF imbalance costs. Thus, the coordination with HPPs is employed only on the intra-day market.
market prices and imbalance penalties are treated as deterministic. The transmission constraints are not considered in the planning.

In [11] a daily planning algorithm is developed for a multi-reservoir hydropower system coordinated with a wind farm. The planning algorithm is based on one of the coordination strategies developed in [7]. Wind power and hydropower are assumed to be owned by different utilities. It is assumed that the wind farm and the hydropower system share the same transmission lines, but that the hydropower 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 hydropower utility for the coordination service. The purpose of the developed coordinated planning is to provide the hydropower utility with optimal hourly bids to the day-ahead market (spot market), considering uncertainty of the wind power forecast.

This paper presents further improvement of the coordinate planning algorithm from [11]. The coordinated planning algorithm considers the uncertainty in the wind power forecast as in [11] and also 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 [12].

The paper is structured as follows: in Section 2 a flow chart for the developed hydropower 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 3. The results obtained when applying coordinated planning are compared to the results when uncoordinated planning is used. Section 4 summarizes the main conclusions of the study and plans for future work.

2. Coordination strategy with wind power

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

1. Base case hydropower planning for the spot market without consideration of wind power.
2. Re-planning of hydropower production for the spot market and the regulating market considering wind power production.

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 [12], where the first stage corresponds to the planning for the spot market, and the second stage corresponds to the planning for the regulating market.

Relevant references on stochastic modeling within an electricity market framework are e.g. [13] that models in detail the day-ahead market and [14] that models in detail day-ahead market, automatic generation control market and balancing market.

The following assumptions are made for the planning:

- The hydropower utility and the wind power utility are price takers. Depending on the generation capacity of the utility this assumption can be reasonable or not. For example the turnover quantities on the Nordic regulating market are small compared to the Nordic spot market implying that the market price is more sensitive to the behavior of the actors on the regulating market. In order to capture this, the actor performance influence on the price must be modeled, see e.g. [14], where the capability of influencing prices in the volatile regulating market is modeled with a revenue function.
- The hydropower 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 (i.e. fair to wind power utility) behavior of the hydropower 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. 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 [15]. 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 hydropower utility as a function of hydro-reservoir content [15]. However, in a discussion with hydropower producers, it was pointed out that by using the water value function the effect on operation of the hydropower system from coordination with the wind farm would extend to longer periods. Operation of the hydropower 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, although it might negatively affect wind energy curtailments.

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.

2.1. Initial data

For the day to which the planning refers (the planning day) input data (blocks 1 and 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 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 sev-
eral successors. The branching continues to the nodes of the last hour of the planning day [16]. The number of 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. hydropower 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.

2.2. Hydropower planning, base case

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

A discharge-generation function of an HPP is non-linear and non-concave. It is approximated here by a concave piecewise linear function where local best efficiency points and the point of maximum discharge of a true generation function are used as the breakpoints [18] (Fig. 3). The slope of each linear segment is called

---

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

Fig. 2. Spot price scenario tree.
the production equivalent, \( \mu_{bu} \). The effect of the head variation of the reservoir is neglected. This simplification is valid for large reservoirs and short-time horizon. More detailed methods of production characteristic modeling are given in [19,17]. However, the application of these methods here would lead to non-linear or mixed integer stochastic optimization problem which is more difficult to solve and requires longer computation time.

Water inflow uncertainty is neglected in the most short-term planning methods in order to limit a size of the optimization problem and thus shorten computational time, e.g. in [17,19]. The inflow uncertainty is usually considered in the mid-term or long-term planning [15]. In this paper both uncertainty associated with market prices and uncertainty of the wind power forecast are considered, thus modeling of inflow uncertainty would increase a size of already huge optimization problem even further. As inflow uncertainty is less significant in the short-term compared to, e.g. uncertainty associated with power market prices, it is not modeled in this paper.

The objective of the hydropower producer is to maximize the expected income \( z_b \) from produced power subject to hydrological constraints, power transmission constraints and technical and environmental limitations of the hydropower system:

\[
\max z^b = \sum_{k \in K, n \in N_k} c^b(k, n) p^b(k, n) \sum_{i \in I, s \in S_i} u_{bs}(k, n) \mu_{bu},
\]

(1)

\[
x_i(k+1, \bar{n}) = x_i(k, n) - \sum_{s \in S_i} u_{bs}(k, n) - y_i(k, n) + w_i(k)
\]

\[
+ \sum_{j \in I_i} \left[ \sum_{s \in S_j} u_{js}(k - \tau_j, n_{\tau_j}) + y_j(k - \tau_j, n_{\tau_j}) \right],
\]

(2)

\[
\forall i \in I, \ \forall k \in K, \ \forall n \in N_k,
\]

\[
\sum_{i \in I, s \in S_i} u_{bs}(k, n) \mu_{bu} - D(k) \leq \bar{P}_{12}, \ \forall k \in K, \ \forall n \in N_k,
\]

(3)

\[
x_i(0) = x_i^0; \quad x_i(n, K_{fast}) = x_i^{fast}, \ \forall n \in N_k,
\]

(4)

\[
0 \leq x_i(k, n) \leq \bar{x}_i; \quad 0 \leq y_i(k, n) \leq \bar{y}_i, \ \forall i \in I, \ \forall k \in K, \ \forall n \in N_k,
\]

(5)

\[
0 \leq u_{bi}(k, n) \leq \bar{u}_i, \ \forall i \in I, \ \forall s \in S_i, \ \forall k \in K, \ \forall n \in N_k,
\]

(6)

where \( u_{bs}(k, n) \) is the water discharge at hour \( k \), at node \( n \) of the decision scenario tree, at HPP \( i \), in a segment \( s \) of the production function; \( S_i \) is an index set of the segments of the production function; \( c^b(k, n) \) is a spot price at hour \( k \), at node \( n \) of the spot price scenario tree; \( p^b(k, n) \) is the probability of the node \( n \); \( N_i \) is a subset of nodes of the spot price scenario tree at hour \( k \); \( x_i(k, n) \) is the reservoir content; \( y_i(k, n) \) is the water spillage; \( w_i(k) \) is the water inflow to the reservoir; \( I_{12} \) is an index set of the HPPs directly upstream of plant \( i \); \( \tau_j \) is a water delay time between HPP \( j \) and HPP \( i \) directly downstream; \( \bar{n} \) is a child node of the node \( n \); \( n_{\tau_j} \) is a relative node of the node \( n \) at hour \( k - \tau_j \), see Fig. 2; \( D(k) \) is the hourly load in the studied site and \( \bar{P}_{12} \) is available transmission capacity from the studied site; \( k \) is the index set of HPPs sharing same transmission capacity with a wind farm; \( x_i^{fast} \) is the initial reservoir content and \( x_i^{last} \) is the reservoir content at the end of the current week; \( K_{last} \) is the last hour in the current week, \( K_{last} \subset K \); \( \bar{y}_i, \bar{y}_j \) and \( \bar{u}_i \) are respectively maximums of reservoir content, water spillage and discharge.

In (2), \( x_i(k + 1, \bar{n}) = x_i(k, n) - \sum_{s \in S_i} u_{bs}(k, n) - y_i(k, n) + w_i(k) \) and the variables \( w_i(k) \) is a parameter. In (3) both parameters \( D(k) \) and \( \bar{P}_{12} \) are assumed deterministic. \( \sum_{i \in I} \sum_{s \in S_i} u_{bi}(k, n) \mu_{bu} \) in (1) is the power that the hydropower producer would bid on the spot market at hour \( k \), for the price \( c^b(k, n) \).

Eq. (3) assumes radial connection from the studied site to the rest of the transmission system, i.e. all net power flows over one transmission corridor with capacity limit defined by TSO. In case of meshed connection dc load flow can be used to approximate the flows on the involved lines which along with transmission constraints ensure that optimal production levels of HPP system are in agreement with available transmission capacities.

The solution to of the base case hydropower planning problem described in Eqs. (1)–(6): 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).

2.3. Wind power production scenarios

Wind power forecasting for about 48 h in advance is an established technique by now. Currently there is a wealth of models (> 50) either at research or commercial level. The accuracy of the short-term prediction has improved during last years. Ref. [22] provides excellent literature overview on the state of art in short-term prediction of wind power and [21] presents the results of the comparison of 12 advanced prediction systems.

The majority of operational prediction tools were initially designed to provide deterministic forecasts. As wind penetration increases, end-users require complementary information on the uncertainty of such forecasts, e.g. for production planning and bidding on the electricity market. Forecast uncertainty estimation is developed in the last years. The state of art now moves to fully probabilistic models that are able to provide directly the predictive probability density functions for each time step of the forecasting horizon [22].

In principle for the planning model developed in this paper any available forecasting and uncertainty estimation model can be used, see, e.g. [10]. As the main focus of this paper is not on the wind power forecasting per se, a wind speed forecast is assumed available and ARMA(1, 1) model for wind speed forecast error developed in [23] is used (block 5). The model simulates possible outcomes of the wind speed forecast error whose stochastic properties are close to those of the actual wind speed forecast error. By sampling from the ARMA(1, 1) 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 \( \Delta v(k, m) \), 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 a wind speed forecast \( \bar{v}(k, m) \) and a wind speed forecast error \( \Delta v(k, m) \):

\[
v(k, m) = \bar{v}(k) + \Delta v(k, m), \quad \forall m \in M_k,
\]

(7)
integrated moving average (ARIMA) [26] and Markov processes [27]. This model is fully described and motivated in [28,29]. This references also provides a literature review on the market price modeling. A brief description of the model follows bellow.

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.
- 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 \( c^i \) takes the occurrence of undefined prices into account by modeling the regulating power prices for hour \( k \) as

\[
c^i(k) = \begin{cases} 
\hat{a}(k), & b(k) = 1, \\
\text{not defined}, & b(k) = 0.
\end{cases}
\]

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 \( \hat{b}(k) \) between the spot and regulating prices as \( a(k) = c^i(k) + \hat{b}(k) \). The spot prices \( c^i(k) \) are known at this stage, while \( \hat{b}(k) \) are stochastic variables modeled with an ARIMA(2, 1, 2) process.

The correlation between the occurrence of upward and downward prices is 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 power price series.

As the production planning is conducted before the spot market closure, the uncertainty of spot prices, upward and downward regulating prices should be considered. The stochastic power market price process \( \xi \) is then three-dimensional, \( \xi = \{C^u(k), C^d(k), C^i(k)\}; \ \forall k \in K \), where \( C^u(k) \), \( C^d(k) \), \( C^i(k) \) respectively denote the stochastic upward regulating price, the stochastic downward regulating price and the stochastic spot price at hour \( k \). In this paper observed historical price series from the 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 regulating market price model. An outcome of the three-dimensional stochastic market price process \( \xi \), corresponding to hour \( k \) and node \( n \) of the power market price scenario tree is denoted \( c^i(k, n) \), \( c^u(k, n) \), \( c^d(k, n) \). Equal probability is assigned to each power market price scenario.

2.5. Scenario reduction and bundling

Wind power production scenarios and power market 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 (blocks 6 and 8) is presented in detail in [16]. The scenario reduction algorithm reduces and bundles the scenarios using the Kantorovich metric, which assures that as many scenarios as possible are reduced without violating a given tolerance criteria.

2.6. Hydropower re-planning coordinated with wind power

In the re-planning part (block 9) of the planning algorithm, the base case hydropower production plan (blocks 3 and 4) is changed to account for wind power. If, according to the base case hydropower production plan (block 4) and wind power production scenario (block 6), transmission congestion is expected, then planned hydropower 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:

\[
\text{if } \sum_{i \in I_c} \sum_{s \in S_i} \mu_{s|k}(i, k) < \bar{P}_w(k, m) - D(k) > \bar{P}_{12},
\]

then \( k, n, m \in K^c(n, m), \tag{9} \]

where \( \sum_{i \in I_c} \sum_{s \in S_i} \mu_{s|k}(i, k) \) is planned hydropower 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 \( k \); \( \bar{P}_{12} \) is available transmission capacity and \( K^c(n, m) \) is index set of congestion hours, for node combinations \( (n, m), K_c \subset K \).

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:

\[
\text{if } \sum_{i \in I_c} \sum_{s \in S_i} \mu_{s|k}(i, k) + \bar{P}_w(k, m) - D(k) \leq \bar{P}_{12},
\]

then \( k, n, m \in K^{nc}(n, m), \tag{10} \]

where \( K^{nc}(n, m) \) is index set of hours without congestion, for node combinations \( (n, m), K_{nc} \subset K \).

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

\[
c < \sum_{k \in K_c} \left( \sum_{i \in I_c} \left( \sum_{s \in S_i} p_{h|k}(i, k) \right) + \bar{P}_w(k, m) - \bar{P}_{12} \right) \sum_{k \in K_c} \left( \sum_{i \in I_c} \left( \sum_{s \in S_i} p_{h|k}(i, k) \right) + \bar{P}_w(k, m) - \bar{P}_{12} \right), \tag{11} \]

where \( p_{h|k}(i, k) \) is hydropower production in stations \( l_c \) without coordination, \( \bar{P}_w(k, m) \) is wind power production and \( c_{h|k}(i, k) \) is a spot price. 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 hydropower utility for the coordination. 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. The exact value of the coordination service price depends on the agreement between the wind power utility and the hydropower utility.

In the re-planning part of the planning algorithm two new variables are introduced: additional discharge \( \Delta u_{ti|k}(i, k, n) \) and power production decrease \( \Delta P_{wi|k}(k, n, m) \). The new variables make it possible to track changes in the coordinated production plan (blocks 9 and 10) compared to the base case plan (blocks 3 and 4) (Fig. 1). Also, as wind power production forecast is uncertain, hydropower production adjustments are planned for each wind power production scenario, \( P_{wi|k}(k, n, m) \) and \( P_{wi|k}(k, n, m) \). 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 [12] and hydropower 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 hydropower 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.

2.6.1. Objective

The objective of the hydropower producer is, as in the base case planning (1), to maximize the total expected income \( z^{tot} \) of the hydropower producer:

\[
\text{max } z^{tot} = z^c + z^{up} - z^d, \tag{12} \]

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 hydropower production adjustments on the regulating market. These are defined as follows:

\[
z^c = \sum_{k \in K} \sum_{n \in N_k} \left( c^i(k, n) q^i(k, n) + \sum_{i \in I_c} s_{SYN} v^i(n) \right) \tag{13} \]

\[
z^{up} = \sum_{k \in K} \sum_{n \in N_k} \Delta P_{wi|k}(k, n, m) \]

\[
z^d = \sum_{k \in K} \sum_{n \in N_k} \Delta P_{wi|k}(k, n, m), \]

Fig. 5. Schematic structure of the scenario tree for stochastic decision process.
\[ z^d = \sum_{k \in K} \sum_{n \in N} \sum_{m \in M_k} q^d(k, n, m)p^r(n)p^m(m)c^d(k, n), \quad (14) \]
\[ z^{up} = \sum_{k \in K} \sum_{n \in N} \sum_{m \in M_k} q^{up}(k, n, m)p^r(n)p^m(m)c^{up}(k, n), \quad (15) \]

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

\[ q^d(k, n) = \sum_{i \in S} [(u_i(k, n) + \Delta u_i(k, n))\mu_i - \Delta P_i(k, n)], \quad (16) \]
\[ q^d(k, n, m) = \sum_{i \in S} p^d_{ia}(k, n, m), \quad (17) \]
\[ q^{up}(k, n, m) = \sum_{i \in S} p^{up}_{ia}(k, n, m). \quad (18) \]

The hourly bids \( q^d(k, n) \) to the spot market are in MWh/h at price \( c^d(k, n) \) in EUR/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 \( P_w(k, m^*) \) for the operating hour is known with certainty and corresponding quantities \( q^d(k, n, m^*) \) and \( q^{up}(k, n, m^*) \) can be chosen from the solution of the optimization problem to bid on the regulating market. In the Nordic market the regulating market closure is half an hour before the operating hour.

**2.6.2. Hydrological constraints**

The hydrological constraints (2) are adjusted as follows:

\[
s_i(k + 1, h, n, m) = s_i(k, n, m) + \sum_{i \in S} u_i(k, n) - y_i(k, n) + w_i(k) + \sum_{j \in J} \left( \sum_{s \in S} u_j(k - \tau_j, n) + y_j(k - \tau_j, n) \right) + \sum_{s \in S} \left( \Delta P_i(k, n) - P^{up}_{ia}(k, n, m) + p^d_{ia}(k, n, m) - \Delta u_i(k, n) \right) + \sum_{j \in J} \sum_{s \in S} \Delta P_j(k - \tau_j, n) + P^{up}_{ia}(k - \tau_j, n, m) - \Delta u_i(k, n) + \sum_{j \in J} \sum_{s \in S} p^d_{ia}(k - \tau_j, n, m) + \Delta u_i(k - \tau_j, n) \forall i \in I, k \in K, n \in N_k, m \in M_k. \quad (19)\]

Here discharges \( u_i(k, n) \), \( u_j(k, n) \) and spillages \( y_i(k, n) \), \( y_j(k, n) \) are already known parameters calculated in the base case planning (blocks 3 and 4) and other quantities are variable. The last three rows in (19) include the effect on the hydro-reservoir content from the hydropower production reduction and from the disposal of stored water, in the local station and the stations directly upstream. The hydropower production reduction \( \Delta P_i(k, n) \) and upward and downward adjustments for the regulating market \( P^{up}_{ia}(k, n, m) \) and \( p^d_{ia}(k, n, m) \) are in MWH. However the reservoir content in the hydrological constraints is expressed in hour equivalents (HE). Therefore \( \Delta P_i(k, n) \), \( P^{up}_{ia}(k, n, m) \) and \( p^d_{ia}(k, n, m) \) are converted to the corresponding water discharge in HE, using the production equivalent \( \mu_i \) of the respective HPP production function.

\[ \text{For the rest of the current week included in the planning, that is for } K_{last}^d < k < K_{last}, \text{ deterministic prices and wind power production scenarios are assumed. However, the decision variables in the last hour of the planning day differ depending on the power market price and wind power production scenarios. Thus the decision variables for the rest of the week are also stochastic. The scenario tree of the decision process from the last hour of the planning day till the end of the current week will consist of parallel branches, each emanating from one scenario dependent state in the last hour of the planning day (Fig. 5). The adjustment bids to the regulating market are not considered for that period, as the average wind power production is assumed for the rest of the current week included in the planning (Fig. 4):} \]

\[ P^{up}_{ia}(k, n, m) = 0, \quad P^d_{ia}(k, n, m) = 0, \quad \forall k > K_{last}^d. \quad (20) \]

**2.6.3. Transmission constraints**

In the coordinated planning, the planned hydropower production at stations \( I_c \) should only be reduced during the hours when congestion on the lines is expected, as expressed in (9), in order to allow wind power production with lower or nil energy curtailment:

\[ \sum_{i \in I_c} \sum_{s \in S} \Delta P_i(k, n) + P^d_{ia}(k, n, m) \leq \sum_{i \in I_c} \sum_{s \in S} \mu_i u_i(k, n) + \bar{P}_w(k, m) - D(k) \quad \forall k, m \in K^t(n, m). \quad (21) \]

Constraint (21) states that stored wind energy should be less than or equal to potential wind energy curtailment during the congestion situation.

Conversely, during the hours when no congestion on the lines is expected, as expressed in (10), additional hydropower production should not exceed the transmission capacity margin:

\[ \sum_{i \in I_c} \sum_{s \in S} \Delta u_i(k, n) + P^{up}_{ia}(k, n, m) \leq \bar{P}_w(k, m) + D(k) \quad \forall k, m \in K^t(n, m). \quad (22) \]

In (21) and (22) \( P^{up}_{ia}(k, n, m) \) and \( P^d_{ia}(k, n, m) \) are recourse variables corresponding to upward and downward power production adjustments at power plant \( i \), at hour \( k \) and node combination \( (n, m) \). These hydropower production adjustments are assumed to be traded on the regulating market shortly before the operating hour, after the outcome of wind power production \( \bar{P}_w(k, m^*) \) becomes known. Thus the recourse variables in (21) and (22) reflect the flexibility offered an intra-day market.

If no congestion on the lines is expected as described in Eq. (10), no additional energy is stored in hydro-reservoirs of the \( I_c \) stations:

\[ \sum_{i \in I_c} \sum_{s \in S} \Delta P_i(k, n) + P^{up}_{ia}(k, n, m) = 0, \quad \forall k, n, m \in K^t(n, m). \quad (23) \]

In congestion on the transmission lines is expected as described in Eq. (9), there should be no additional hydropower production in the \( I_c \) stations, that is

\[ \sum_{i \in I_c} \sum_{s \in S} \Delta u_i(k, n) + P^{up}_{ia}(k, n, m) = 0, \quad \forall k, n, m \in K^t(n, m). \quad (24) \]

**2.6.4. Fixed values and limits**

Initial reservoir content is assumed known and reservoir content at the end of the planning period is fixed in accordance with midterm production planning:

\[ x_i(0, n, m) = x_i^0, \quad \forall n \in N_0, m \in M_0. \quad (25) \]
There are also reservoir content limitations, similar to those in the base case planning (5) and (6):

\[ 0 \leq x_{i}(k, n, m) \leq \bar{x}_{i}, \quad \forall i \in I, \forall k \in K, \forall n \in N_{k}, m \in M_{k}. \]  

(27)

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

\[ \Delta P_{i}^{d}(k, n) + \frac{P_{i}^{up}(k, n, m)}{\mu_{is}} \leq \bar{u}_{i} - u_{i}(k, n), \]

\[ \forall i \in I, \forall s \in S, \forall k \in K, \forall n \in N_{k}, m \in M_{k}. \]  

(28)

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

\[ \Delta u_{i}(k, n), \Delta P_{i}^{d}(k, n), P_{i}^{up}(k, n, m), P_{i}^{up}(k, n, m) \geq 0, \]

\[ \forall i \in I, \forall s \in S, \forall k \in K, \forall n \in N_{k}, m \in M_{k}. \]  

(29)

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 (12) subject to the constraints (13)–(30).

3. 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 30–90 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 hydropower 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 modeled 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 hydropower planning and the coordinated planning with wind power is done successively day by day for 1 week. The results are then compared.

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 the Ume river from 2001 is used as input data.
- Reservoir contents of the HPP system at the end of the week are fixed (data from 2001).
- The actual wind speeds from the studied site in 2001 are used as the wind speed forecast as wind speed forecast data were not available.

Forecast error is modeled as described in Section 2.3. Forecast error data from Eastern Denmark in 2003 are used to calculate parameters for the ARMA model of forecast error.

- Thousand forecast error scenarios are first generated by sampling from ARMA model, forecast error scenarios are then added to wind speed forecast to obtain wind speed scenarios.
- The power curve of the 2 MW wind turbine Vestas 80 is used to convert wind speed scenarios to power production scenarios. The wind farm smoothing effect is not considered.
- The spot market price scenarios are generated by sampling form historical prices for 82 first week days in 2004. This means that 82 price scenarios, covering 24 h, were defined. For each spot price scenario, one upward and one downward regulation power price scenario were generated by sampling from the regulating market price model.
- The HPP system is assumed to operate according to the production plan, corresponding to “actual” outcome of spot and regulating market prices (data from 2004) and “actual” outcome of wind power production (data from 2001).

The developed planning model has been implemented in General Algebraic Modeling System (GAMS), [30], the solver CPLEX is used to solve the large-scale linear optimization problem.

The re-planning model consists of 27 blocks of equations and 6 blocks of variables. For example, with 50 price scenarios (reduction by 20%) and 4 wind scenarios (reduction by 60%) the total number of variables is 1,300,441, and it takes about 10 min to solve the base case problem and re-planning problem with Intel(R), Core(TM) Duo, CPU 2.33 GHz, 2 GB RAM.

Gradually increasing amount of wind power and price scenarios, due to a huge number of variables, a memory shortage becomes a problem in the model generation stage of the re-planning model. On the 32-bit system it is impossible to generate a model with more than about 6 wind scenarios (50% scenario reduction) and 50 price scenarios, due to the fact that planning horizon stretches over 1 week. It was necessary to obtain trial 64-bit version of GAMS and

\[ \text{Tuesday was chosen as a planning day here, i.e. the rest of the week included in planning consists of 5 days.} \]
run it on 64-bit Windows to check sensitivity of the objective function to amount of wind power and price scenarios. Number of wind scenarios has much stronger impact on number of variables than number of price scenarios. On the other hand change in wind power scenario reduction by 10% results in objective function change by 0.01–0.02%, i.e. very small whereas change in price scenario reduction by ca. 10% results in objective function change by 0.1–0.15%. It is possible to decrease a problem size by including in the planning, e.g. only two to three following days after the planning day instead of the whole week.

Fig. 7 shows hydropower 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 hydropower production from the first five HPPs is as high as the available transmission capacity. In the coordinated case, hydropower production at these stations is reduced to free some transmission capacity for wind power production. 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 hydropower system has priority to use the transmission capacity from the studied area, wind power production is calculated considering the transmission margin left after hydropower 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, i.e. by almost 75%. Some wind energy curtailment still prevails due to the technical limitations of the considered HPP system.

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 hydropower are not coordinated. Available transmission capacity is also used more intensively in the coordinated case.

Actual daily income of HPP system is calculated substituting actual power prices and actual wind power production as follows:

\[
\begin{align*}
\text{z}^{\text{tot}} &= \text{z}^c + \text{z}^{\text{up}} - \text{z}^d, \\
\text{z}^c &= \sum_{k \in K} \left( c^i(k) q^i(k, n^i) + \sum_{i \in I_c} \sum_{s \in S_i} c \Delta P_{w}(k, n^i) \right), \\
\text{z}^d &= \sum_{k \in K} q^d(k, n^*, m^*) c^d(k), \\
\text{z}^{\text{up}} &= \sum_{k \in K} q^{\text{up}}(k, n^*, m^*) c^{\text{up}}(k),
\end{align*}
\]

where \(n^*, m^*\) is the combination of the nodes of the decision scenario tree, Fig. 5, corresponding to actual realizations of the power market prices and the wind power production at hour \(k\).

For the studied week the income of the HPP system is 1.6 × 10^6 EUR in the uncoordinated case and 1.9 × 10^6 EUR in case when hydropower 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 EUR and, in the case with coordination, 8.6 × 10^5 EUR. The difference is not high due to the fact that the maximum price for the coordination service in (11) is applied in...
this case study. In practice this price should be based on agreement between the hydropower and the wind power utility and would be less than the maximum value defined by (11).

4. Conclusions and future work

This paper has presented the developed short-term hydropower 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 hydropower can be beneficial for both the wind power utility and the hydropower 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 hydropower 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 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 hydropower plants would need to be investigated.

References

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Sharing of Profit from Coordinated Planning and Bidding of Hydro and Wind Power

Julija Matevosyan, Marija Zima-Bočkarjova, Marek Zima and Lennart Söder

Abstract—Depending on market rules, namely congestion management and balancing management, a coordination between wind and hydro producers may be beneficial for both of them. In this paper we propose a new collaboration scheme and fair and transparent method, based on Shapley value, for splitting the extra value caused by a coordinated bidding and operation strategy.

We account on uncertainties in wind forecast and energy price evolution. We demonstrate the proposed approaches on a realistic system including congested lines, wind park and a hydro plant consisting of several reservoirs stages.

Index Terms—wind power production, hydro power production, stochastic optimization, coordinated planning, Shapley value

I. NOTATION

The notation used throughout the paper is listed below for a quick reference:

A. Variables

- $\phi_l(c)$ profit share of the entity $l$, Shapley value
- $b$ continuous variable
- $c$ coalition profit
- $c^a$ spot price
- $c^{imb}_{pos}$ overproduction price, EUR
- $c^{imb}_{neg}$ underproduction price, EUR
- $c^{up}$ upregulation price, EUR
- $i$ hydro power plant
- $j$ hydro power plant directly upstream from $i$
- $k$ hour
- $l$ entity joining coalition
- $m$ wind scenario
- $n$ price scenario
- $P_{av}$ monthly average available wind power equivalent, MW
- $P_w$ wind farm installed capacity, MW
- $P_{wsc}$ production of wind submitted to spot, MW
- $P_{wnc}$ available wind power equivalent, MW
- $P_{wc}$ actual wind power production, MW
- $P_{h}$ production of hydro unit submitted to spot, MW
- $P_{hsc}$ actual hydro unit production, MW
- $s$ hydro unit at power plant
- $u_{is}$ water discharge from unit $s$, plant $i$, HE
- $x_i$ reservoir content of $i$-th HPP
- $y_i$ water spillage from plant $i$, HE

B. Constants

- $p$ success probability of a price scenario
- $q$ success probability of a wind scenario
- $\mu_{is}$ production equivalent unit $s$ of HPP $i$, MW/HE
- $\tau_{ij}$ time delay for water inflow from HPP $i$ and the reservoir downstream $j$
- $n_C$ dimension of the set $C$
- $n_A$ number of entities
- $P_{12}$ transmission corridor capacity, MW
- $u_{is}$ maximal water discharge from unit $s$, plant $i$, HE
- $x_i$ maximum reservoir content
- $x_0^i$ initial reservoir content of $i$-th HPP
- $x_{fast}^i$ final reservoir content of $i$-th HPP
- $w_i$ water inflow to the reservoir $i$

C. Numbers

- $D$ large number

D. Sets

- $\Omega_i$ index set of HPPs upstream of plant $i$
- $A$ all coalition members
- $C$ formed coalition
- $I$ index set of HPPs
- $K$ hours of the total planning horizon
- $K_{day}$ hours of the next planning day
- $M$ set of wind scenarios
- $N$ set of price scenarios
- $S_i$ index set of units at HPP $i$

II. INTRODUCTION

Attractive features of a wind production, similarly to other renewables, are: environmental friendliness - particularly negligible emissions and low production costs, in many countries supported by subsidies or infeed tariffs and regulations. The European Union has set a binding target of 20% of the energy demand to be covered by wind and other renewable sources by 2020. In order to achieve this target, more than one-third of the electrical energy should be produced by the renewables, with wind farms expected to supply 12 – 14% of the total electricity consumption [1].

The most significant challenge of wind production comparing to traditional resources are its nature not allowing an accurate planning or scheduling of its energy production and a significant volatility of its instantaneous power
production. From the perspective of a Transmission System Operator (TSO) these disadvantages result in a higher demand for control reserves, balancing deviations between production and consumption in a power system. Costs for keeping and employing control reserves TSO charges consumers and producers based on the deviations of their actual production or consumption from the scheduled production or consumption, i.e. an incurred balancing energy. Note that thus from the perspective of a producer, or a consumer only energy deviations are penalized, instantaneous power deviations are not and therefore in our further considerations we include only the energy aspect.

The amount of balancing energy introduced by a wind power plant can be minimized by creating a coordination scheme together with a well controllable type of a power plant, for example a hydro power plant. If both power plants are geographically located close to each other and share a part of their connection to a transmission system, coordination becomes even more of interest, mostly in the cases of a congested connection to the power system.

The coordination of wind power and hydro power has been studied earlier in connection with several different problems. Ref. [2] provides comprehensive literature review on wind-hydro coordination. 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 versus a new wind farm. 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.

In [8] the dynamic programming algorithm is presented for a daily planning of coordinated operation of wind parks and generic energy storage in area with limited export capability. In [9] the optimization problem is formulated for daily production planning of wind park and pumped storage hydro power plant, though transmission bottlenecks are not considered.

One of the most recent publications on coordinated planning of wind and hydro power plants is [10]. In that paper the coordination is applied in order to minimize WF imbalance costs.

In [11] a stochastic daily planning algorithm is developed for a multi-reservoir hydro power system coordinated with a wind farm. The planning algorithm is based on one of the coordination strategies developed in [7]. This algorithm [11] suggests that first, wind producer shall determine its optimal production and get corresponding transmission capacity. Second, hydro producer determines optimal production based on the remaining available transmission capacity. WF shall pay HPP an annual average spot price for the obtained capacity, which was freed by HPP comparing to its uncoordinated schedule. WF payments for the imbalances were not considered. Additionally, HPP can bid to the balancing market, if WFs cannot use all the previously allocated capacity. If available wind power exceeds scheduled production and the downregulation bid of hydro is not accepted, wind is discarded without creating an income.

In none of the above mentioned publications neither in others to our knowledge, a splitting scheme for the profit obtained by the coordination has been proposed.

Objective of our paper is to present 2 contributions:

1) A new coordination scheme employing stochastic optimization to maximize total profit of the wind-hydro coalition, including the imbalance penalties.
2) A new fair and transparent method, based on Shapley value, for splitting the extra value caused by a coordinated bidding and operation strategy.

The papers is structured as follows: first we describe the addressed problem and the overall proposed scheme. The next two sections go more into the details of the components of the proposed scheme - profit sharing principles and the coordination strategy. Then we demonstrate theoretical concepts on a realistic example, followed by comments and concluding remarks.

III. PROBLEM FORMULATION AND THE PROPOSED SCHEME

The problem we address is inspired by an actual case occurring in Sweden. Main consumption centers, i.e. cities are geographically located in the southern part of Sweden. On the other hand, convenient and economically attractive conditions for power production are available in the northern part of Sweden. Rivers flowing through long valleys have given a rise to many hydro power plants with several hydrologically coupled reservoirs. The transmission system bringing power from each river cascade and also from the whole northern part of Sweden to the South are frequently congested. This restricts the otherwise promising potential of installation of wind power plants in the North.

This could by overcome by a planning and operation coordination scheme. A necessary characteristic of such scheme is an incentive for all involved parties to cooperate. In a market environment this can be achieved only by a fair sharing of profit resulting from the coordination.

To assure applicability of our approach in a wider scope in various power systems and market conditions, we take the addressed problem to a higher level of abstraction and the resulting targeted problem can be described as follows.

There are two independent generation companies. One of them posses a hydro power plant consisting of several reservoirs. The second company operates a wind power plant. Both power plants are located in a geographical proximity to each other and thus are injecting power in the same substation, which is connected via a line or a group of lines to the rest of the power system as shown in the figure 1.

Within the assumed market environment electricity is traded via a spot market with day-ahead nominations and clearing. Accepted bids are to be scheduled and nominated to the TSO. Deviations from schedules are penalized by imbalance fees charged by the TSO.

The TSO also bears responsibility for congestion management, where the rule "first come, first served" applies. In
other words, the transmission capacity is allocated in the order in which producers have historically been connected to the network. In this example, the first built and connected power plant was the hydro power plant. Thus the hydro power plant has priority in nominating and allocating the transmission capacity.

Individual uncoordinated planning of production and bidding yields a suboptimal situation for all involved parties. Producers may suffer from a lower economical efficiency (e.g. wind power production can be curtailed) and a frequent TSO interference in the congestion management may be necessary.

Our proposal is to coordinate (as far as legislation allows) planning and bidding strategy of the wind and hydro power producers. In many systems, a shared bidding strategy by two or more market participants could be perceived to have cartel agreement elements, not allowed by law. On the other hand, legislation allows merges of power production companies, unless the resulting market share exceeds a certain value. Therefore we make an assumption, that there is a legal construction enabling a coordinated planning and bidding of power producers. How this construction looks like, is out of the scope of this paper and would be very country specific.

Besides power producers, also TSO may benefit from the coordination of the producers, which would bring a self-regulating effect of producers, which should be actually a desired property of the transmission system operation [14]. Benefit for TSO would be twofold: a minimal need for TSO intervention in the congestion management (in other words no TSO does not have to initiate any congestion relief actions, as the concerned market participants initiate them themselves) and a high utilization of transmission assets.

A coordinated planning and bidding would yield a benefit on the side of power producers, allowing them to optimize their profits by means of optimal utilization of their production facilities with respect to external conditions (such as in this case transmission restriction) and their technical properties (in this case storage capability of the hydro power plant and low production costs of the wind power plant).

IV. SHARING OF PROFIT BETWEEN PRODUCERS

To provide an incentive for producers to coordinate their planning and operation, a scheme for sharing either production costs, or resulting profit has to be applied. This scheme has to be transparent and fair, in other words the additional benefit brought by the participation of each producer has to be evaluated and allocated. According to game theory, these properties are guaranteed by the concept of so called Shapley value.

Shapley value and similar Aumann-Shapley value applications to cost and/or profit allocation problems were already suggested in the literature for several areas of power systems, including expansion planning [15], congestion management [16], inter- TSO compensations [19], ancillary services [17] and fixed asset costs [18] and loss allocation [20]. In [18] the game theoretic approach combined with optimization is suggested mainly for the recovery of the fixed transmission charges, i.e. transmission assets cost.

We adopt Shapley value, which suggests, that a new entity \( l \) joining a coalition \( C \) shall be allocated all the additional profit she brings to the coalition: \( \Delta c(C, l) = c(C \cup \{l\}) - c(C) \). This additional profit however depends on the existing coalition and the order, in which the entities join the coalition. For the set \( A \) of \( n_A \) entities, there is \( n_A! \) possible orderings. Define \( C \subseteq A \setminus \{l\} \), as any subset of \( A \) excluding \( l \) and with the dimensions \( |C| = n_C \). The probability that precisely set \( C \) comes before \( l \) in a random ordering is \( \frac{n_C!(n_A-1)!}{n_A!} \). Thus, the Shapley value determining the profit share ratio of the entity \( l \) can be defined as follows [21]:

\[
\phi_l(c) = \sum_{n_C=0}^{n_A-1} \left[ \frac{s!(n_A-1-n_C)!}{n_A! \sum_{C \subseteq A \setminus \{l\} \atop |C|=n_C} \Delta c(C, l) \right] \tag{1}
\]

where \( \phi_l(c) \) indicates a profit share of \( l \in A \), \( c \) is the profit in the coalition, \( \Delta c(C, l) = c(C \cup \{l\}) - c(C) \).

Naturally, the profit shares of all the entities add up to the profit of the coalition:

\[
\sum_{l \in A} \phi_l(c) = c. \tag{2}
\]

In our case we treat a profit sharing from a coordinated use of the transmission capacity. This transmission capacity has been allocated to the first producer connecting to the grid at this point, i.e. hydro power plant. The Shapley value guarantees fairness of the profit sharing between the hydro and wind producer, if they form a coalition for a coordinated use of the transmission capacity. Thus, we compute how the aggregated profit of these two entities changes, when they form a coalition. To preserve the transparency we suggest that the following procedure would take place on a basis of the planning and operation horizon, i.e. in this case of short-term day ahead planning every day:

1) The data for the previous day are collected. These data include input parameters (e.g. wind speeds, water inflows, spot prices) and profit data resulting from the coordinated planning and operation: revenues from the sale of the energy (e.g. on the spot market) and the balancing energy costs.
2) Hypothetical profit data for the individual, uncoordinated operation of producers are computed.
3) The profit figures for coordinated and uncoordinated strategy are inserted into the expression (1) and the profit
share for the previous planning and operation day is determined.

To demonstrate the advantage of the coordinated planning and operation before it actually happens, the first above point can be determined based on the simulation of the coordinated strategy. This is described in the next section.

V. PLANNING AND BIDDING STRATEGIES

First we describe planning and bidding strategies in general terms, focusing on the intuitive interpretations. The general expressions are explained in a detail afterwards. All planning strategies are made day ahead, resulting into a bid submitted to the spot market for the coming day. The considered planning horizon is one day, however taking into account also the rest of the week in a form of an averaged model, i.e. expressing an average expected wind production during the rest of the week and a value of a possible hydro power production during the rest of the week. This is shown in the figure 2, which captures possible evolutions of stochastic factors, in our approach spot prices and wind speeds, during the production day. Each branch of the tree corresponds to one scenario with a particular wind speed, a spot price and an assigned probability of the occurrence.

For the rest of the current week included in the planning, that is for $k_{last}^{day} < k \leq K_{last}$, deterministic prices are assumed. Wind power production is limited by average monthly wind power production base on historical data, i.e. $P_{w}(k, n) = P_{av}$. 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.

The following imbalance price model, as seen from the producer (or more generally a balance group, commonly abbreviated as BG) and shown in the figure 3, is used:

$$c_{imb}^{pos}(k, n) = \begin{cases} c^{s}(k, n) & \text{if system is short} \\ c^{d}(k, n) < c^{s}(k, n) & \text{if system is long} \end{cases}$$

where $c^{d}(k, n)$ is a price for downward regulation.

The penalty for the underproduction is defined, as follows:

$$c_{imb}^{neg}(k, n) = \begin{cases} c^{up}(k, n) > c^{s}(k, n) & \text{if system is short} \\ c^{s}(k, n) & \text{if system is long} \end{cases}$$

where $c^{up}(k, n)$ is a price for upward regulation.

This model does not target to reproduce balancing energy payment rules of a particular market. This model rather represents a general concept of penalizing imbalances so the formulations we further propose could be applied in the context of various markets.

A. Individual Strategies

When power producers do not coordinate their strategies, they plan individually as follows.

1) Hydro Power Plant: We assume that the hydro power plant does not cause any imbalance, i.e. it can follow its scheduled production perfectly and thus its objective can be expressed as a pure maximization of the profit from the energy accepted at the spot market subject to the price uncertainty. We do not address structuring of the bids, but consider that it is possible to submit price dependent bids and thus, we can optimize for the scheduled energy for each market clearing price scenario:

$$\max z_{h}^{s}$$ (3)

s.t. $g_{bb}^{h} = 0$ (4)

$g_{rl}^{h} = 0$ (5)

$h_{rl}^{h} \leq 0$ (6)

$h_{d}^{h} \leq 0$ (7)

$h_{l}^{h} \geq 0$ (8)
The set of constraints from (4) to (7) describe hydrological properties of a hydro power plant, explicitly: \( g_{hbb}^h \), \( g_{rt}^h \) are hydrological balance constraints, \( g_{rt}^h \) are reservoirs’ targets provided by the medium-term planning, \( h_{lt}^b \) are reservoirs’ limits and \( h_{lt}^b \) are discharge limitations.

Hydro power producer has a higher priority for the allocation of the transmission capacity, therefore its planning and operation is completely decoupled from the wind farm and thus the constraint (8) takes into account only own production. In other words, this constraint limits the overall production of the hydro power plant to the value given by the rating of the transmission line.

2) Wind Farm: Due to the stochastic nature of the wind, wind farm in its actual production may deviate from the scheduled production and thus induce an imbalance with respect to its bid to the spot market. This is included in the cost function as well as in the auxiliary constraints (10) and (11):

\[
\text{max } z_s^w + z_{imb}^w \quad (9)
\]
\[
\text{s.t. } g_{imb}^w = 0 \quad (10)
\]
\[
h_{imb}^w \leq 0 \quad (11)
\]
\[
h_{imb}^w \quad (12)
\]

The amount of energy, which can be injected into the network by the wind farm according to the equation (12), is given as a remaining transmission capacity after the allocation of the hydro power production injection.

B. Coordinated Strategy

The objective in the coordinated strategy is to maximize the overall profit from the combined production of the hydro power plant and the wind farm:

\[
\text{max } z_s^h + z_s^w + z_{imb} \quad (13)
\]
\[
\text{s.t. } g_{hb}^h = 0 \quad (14)
\]
\[
g_{rt}^h = 0 \quad (15)
\]
\[
h_{ib}^h \leq 0 \quad (16)
\]
\[
h_{ib}^b \leq 0 \quad (17)
\]
\[
g_{imb}^w = 0 \quad (18)
\]
\[
h_{imb}^w \leq 0 \quad (19)
\]
\[
h_{imb}^h + w \leq 0 \quad (20)
\]

Both hydrological and wind imbalance constraints have to be met. The transmission constraint in this case couples production from both power plants.

C. Terms of Optimizations

1) Objective function term \( z_s^h \):

\[
z_s^h = \sum_{k \in K} \sum_{n \in N} c^s(k, n)p(k, n) \sum_{i \in I} \sum_{s \in S_i} P_{is}^s(k, n) \quad (21)
\]

2) Objective function term \( z_s^w \):

\[
z_s^w = \sum_{k \in K} \sum_{n \in N} c^w(k, n)p(k, n)P_{ls}^s(k, n) \quad (22)
\]

3) Objective function terms \( z_{imb} \) and \( z_{imb}^w \):

\[
z_{imb} = \sum_{k \in K_{day}} \sum_{n \in N} \sum_{m \in M} \{ P_{imb}^{imb}(k, n) \cdot p(k, n) \cdot q(k, m) \cdot (1 - b(k, n, m)) \cdot \\
( P_{imb}^w(k, n, m) - P_{imb}^w(k, n) + \\
\sum_{i \in I} \sum_{s \in S_i} \{ P_{imb}^{sc}(k, n, m) - P_{imb}^{sc}(k, n) \}) \\
- c_{imb}^{imb}(k, n) \cdot p(k, n) \cdot q(k, m) \cdot b(k, n, m) \cdot \\
( P_{imb}^w(k, n, m) - P_{imb}^w(k, n) + \\
\sum_{i \in I} \sum_{s \in S_i} \{ P_{imb}^{sc}(k, n, m) - P_{imb}^{sc}(k, n) \}) \}
\]

The objective function term (23) is valid for the coordinated study. For the uncoordinated case it naturally follows that \( z_{imb}^w \) does not contain any hydro related terms.

4) Complementarity constraints: The constraints below encode conditions for the charges for the imbalance of the producers and allow only either positive or negative imbalance.

The use of continuous variable for \( b \) - a switch of one or the other imbalance term, is allowed by introducing the complementarity constraint:

\[
b(k, n, m)(1 - b(k, n, m)) = 0, \quad \forall k \in K, \forall n \in N, \forall m \in M.
\]

The objective function (23) specifies that the overproduction of the coalition corresponds to the \( b = 0 \) condition, i.e. underproduction is negative in this case, while the underproduction corresponds to the \( b = 1 \) and the overproduction is negative.

The inequalities below specify these conditions and “enable” the accordance of terms in the objective function. Thus, for the positive imbalance term:

\[
(1 - b(k, n, m)) \geq P_{imb}^{sc}(k, n, m) - P_{imb}^w(k, n, m) + \\
\sum_{i \in I} \sum_{s \in S_i} \{ P_{imb}^{sc}(k, n, m) - P_{imb}^{sc}(k, n) \} \quad \forall k \in K_{day}, \forall n \in N, \forall m \in M.
\]

simultaneously, the negative imbalance is constrained:

\[
Db(k, n, m) \geq - P_{imb}^{sc}(k, n, m) + P_{imb}^w(k, n) - \\
\sum_{i \in I} \sum_{s \in S_i} \{ P_{imb}^{sc}(k, n, m) - P_{imb}^{sc}(k, n) \} \quad \forall k \in K_{day}, \forall n \in N, \forall m \in M,
\]

where \( D \) is a large positive number that exceeds any maximum feasible value of the imbalance.
Besides, the hydro production is limited by the technical and environmental water discharge constraints:

\[ P_{w}^{sc}(k, m) - P_{w}^{a}(k, n, m) = 0 \]
\[ \forall k > K_{last}, \forall n \in N, \forall m \in M, \tag{27} \]

and

\[ P_{ts}^{sc}(k, n, m) - P_{ts}^{a}(k, n) = 0, \]
\[ \forall k > K_{last}, \forall i \in I, \forall s \in S, \forall n \in N, \forall m \in M. \tag{28} \]

6) Hydrological balance constraints \( g_{h}^{d} \): Actual hydro unit production is defined by the production equivalent and the water discharge:

\[ P_{ts}^{sc}(k, n, m) = \mu_{is}u_{is}(k, n, m) \]
\[ \forall i \in I, \forall s \in S, \forall k \in K, \forall n \in N, \forall m \in M. \tag{29} \]

Reservoir content results from the discharges of the power plant, the inflows of hydro systems and the delayed discharges of the HPP upstream:

\[ x_{i}(k + 1, n, m) = x_{i}(k, n, m) + \]
\[ w_{i}(k) - y_{i}(k, n) - \sum_{s \in S} P_{ts}^{sc}(k, n, m) + \]
\[ \sum_{j \in \Omega} y_{j}(k - \tau_{ij}, n, \tau_{ij}) + \sum_{j \in \Omega, s \in S} P_{is}^{sc}(k - \tau_{ij}, n, \tau_{ij}) \mu_{js} \]
\[ \forall i \in I, \forall k \in K, \forall n \in N, \forall m \in M. \tag{30} \]

7) Reservoirs’ targets’ constraints \( g_{h}^{t} \): Initial reservoir content is assumed known and reservoir content at the end of the planning period is fixed in accordance with mid-term production planning:

\[ x_{i}(0, n, m) = x_{i}^{0}, \]
\[ \forall i \in I, \forall n \in N, \forall m \in M. \tag{31} \]

\[ x_{i}(K_{last}, n, m) = x_{i}^{last}, \]
\[ \forall i \in I, \forall n \in N, \forall m \in M. \tag{32} \]

8) Reservoirs’ limits’ constraints \( h_{h}^{l} \): There are also reservoir content limitations.

\[ 0 \leq x_{i}(k, n, m) \leq \bar{x}_{i}, \]
\[ \forall i \in I, \forall k \in K, \forall n \in N, \forall m \in M. \tag{33} \]

9) Hydro production inequality constraints \( h_{h}^{i} \): In addition, bid to the spot market shall not exceed the installed capacity:

\[ 0 \leq P_{ts}^{a}(k, n) \leq \mu_{is} \bar{u}_{is} \]
\[ \forall i \in I, \forall s \in S, \forall k \in K, \forall n \in N. \tag{34} \]

Besides, the hydro production is limited by the technical and environmental water discharge constraints:

\[ 0 \leq P_{ts}^{sc}(k, n, m) \leq \mu_{is} \bar{u}_{is}, \]
\[ \forall i \in I, \forall s \in S, \forall k \in K, \forall n \in N, \forall m \in M. \tag{35} \]

10) Wind production inequality constraints \( h_{w}^{imp} \): Wind power bid to the spot market is defined in the following interval:

\[ 0 \leq P_{w}^{a}(k, n) \leq \tilde{P}_{w} \]
\[ \forall k \in K, \forall n \in N, \tag{36} \]

Note that actual wind power production is limited to the available wind:

\[ 0 \leq P_{w}^{sc}(k, n, m) \leq \tilde{P}_{w}^{sc}(k, m) \]
\[ \forall k \in K, \forall n \in N, \forall m \in M \tag{37} \]

11) Transmission constraints \( h_{t}^{h+w}, h_{t}^{w} \) and \( h_{t}^{h+w} \): Transmission constraints \( h_{t}^{h+w} \) valid for the coordinated study are:

\[ P_{w}^{sc}(k, n, m) + \sum_{i \in I, s \in S} P_{is}^{sc}(k, n, m) \leq \tilde{P}_{12} \]
\[ \forall k \in K, \forall n \in N, \forall m \in M \tag{38} \]

In the uncoordinates cases, in the constraints \( h_{t}^{w} \) and \( h_{t}^{h+w} \), accordingly wind or hydro production term shall be omitted.

VI. Case Study

A. System Description

The example we consider has the following characteristics:

- As shown in figure 1, the power plant consists of 5 interconnected reservoirs. The overall rating of generators of the hydro power plant is 250 MW.
- The wind farm has the nominal power rating of 60 MW.
- The energy is injected into the rest of the transmission system via the line with the limit of 250 MW.
- There is no local load connected to the same bus.
- The inflow data correspond to recordings of Úme river from 2001.
- There are three wind scenarios for each day and they are derived from real recordings.

![Wind power scenarios](image1.png)

Figure 4. Scenarios considered for the planning of the first day in the week. Wind scenarios have the probability from the top to the bottom: 0.38, 0.223, 0.397. The price scenarios have the probabilities from the top to the bottom: 0.037, 0.866, 0.097
There are three price scenarios for each day. The prices are based on averaged actual prices in Nordel in 2004. Both for individual and coordinated strategies the same input data are used. An example for the first day of the week and averaged values representing the rest of the week is shown in figure 4.

For evaluation and comparison of strategies, the realization of input scenarios as shown in figure 6 is applied. After determining individual and coordinated strategies this realization is inserted into equations (21), (22) and (23) to obtain financial figures allowing comparison of the uncoordinated and coordinated strategy.

The stochastic optimization has been implemented in GAMS [13].

B. Individual Strategy

Applying individual uncoordinated strategies yields results as shown in the figure 5. Hydro power producer plans his production first and as it has a higher priority in the allocation of the transmission capacity, he fully utilizes the transmission capacity during the expected price peak hours. Wind farm producer adjusts his bid to this and goes down to zero production even though wind is expected to be available. Besides this, there are several cases, when actual wind production exceeds bid.

C. Coordinated Strategy

Results of the coordinated strategy are shown in the figure 7. As expected, the coordinated strategy leads to a full utilization

Figure 5. Bids to the spot market and the actual production in the uncoordinated case. The blue solid line is hydro power production and the solid green line wind power production respectively. The bids are expressed by the dashed violet line. The solid black line corresponds to an available wind power production.

Figure 6. Realization of stochastic variables expressed by the thick black solid line.

Figure 7. Bid to the spot market and the actual production in the coordinated case. The blue solid line is hydro power production and the solid green line wind power production respectively. The common bid is expressed by the dashed violet line. The solid black line corresponds to the overall production of the hydro and the wind power.

Figure 8. Comparison of the uncoordinated and coordinated strategy. The shaded area represents coordinated strategy, whereas the solid black line expresses the sum of uncoordinated strategies.
of the transmission capacity without a need for spillage of the wind farm production due to the adjustment of the hydro power production. However, occasional overproduction of the wind resulting into exceeding of the common bid of the hydro power plant and the wind farm could not be avoided.

The opportunity revenues of both producers, while no significant change in penalties for balancing energy is observed. The coordination strategy leads to the increase of the sum of power plant and the wind farm could not be avoided.

D. Profit Sharing

The profit of a producer(s) is obtained by summing up revenues and balancing payments, which can be either negative, or positive depending on the type of imbalance. The comparison of profits for the uncoordinated and coordinated cases is summarized in the table I.

<table>
<thead>
<tr>
<th>Producer</th>
<th>Individual strategy</th>
<th>Coordinated strategy</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydro Power Plant</td>
<td>579 956.0</td>
<td>590 107.95</td>
</tr>
<tr>
<td>Wind Farm</td>
<td>91 332.4</td>
<td>101 484.35</td>
</tr>
<tr>
<td>Overall profit</td>
<td>671 288.4</td>
<td>691 592.3</td>
</tr>
</tbody>
</table>

While the allocation of profits among the producers is straightforward in case of the individual strategies, for the coalition we apply Shapley value (1) to profit allocation.

Both orderings - hydro is the first member of coalition and hydro joins the coalition as the second member have 50% probability. Therefore, for the hydro producer we get:

\[ \phi_h(c) = \frac{1}{2} \times 579956 + \frac{1}{2} \times (691592.3 - 91332.4) = 590107.95. \]  

Similarly, profit share of the wind producer is:

\[ \phi_w(c) = \frac{1}{2} \times 91332.4 + \frac{1}{2} \times (691592.3 - 579956.0) = 101484.35. \]

Thus, for this particular example and the particular set of conditions an increase of profit of 11% is achieved for wind producer and 1.8% for the hydro producer if they coordinate their planning and bidding comparing to their uncoordinated operation.

VII. Concluding Remarks

This paper addresses the problem of two producers injecting power into the transmission grid via a line with insufficient capacity to accommodate a peak production from both producers. We present how these two producers can coordinate their planning and bidding strategies by means of stochastic optimization and by doing so, they may achieve a higher common profit than without coordination. We propose how this profit may be fairly shared by these producers applying the concept of Shapley value from the game theory. We use a realistic example to demonstrate applicability of our proposals.

Note, that although we considered a particular example consisting of a wind and hydro producers, the concepts we introduce in this paper can be applied on various types of power producers, which could benefit from a coordinated planning and bidding strategy.

In this paper we assumed that only day-ahead coordination in the planning and bidding stage takes place. This has some advantages, as only a limited amount of information and in a time noncritical manner have to be exchanged between the producers.

Even a stronger coordination also in the real-time operation, requiring an appropriate communication infrastructure, might be implemented. In addition to the maximization of revenues in the planning stage, this would allow a minimization of balancing energy costs. This can be seen as a promising future research direction.

References


VIII. BIOGRAPHIES

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Effect of wake consideration on estimated cost of wind energy curtailments

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Abstract–Measures such as energy curtailment or grid reinforcement are required to integrate the upcoming wind generation in parts of the power system with existing transmission bottlenecks. In order to choose between these two measures potential wind energy curtailments and its costs need to be carefully evaluated. The paper analyzes the effect of wake consideration on the overall energy curtailment cost. For this purpose detailed wake model was used taking into account partial and multiple shading of wind turbines. A comparison of curtailment cost with cost for grid reinforcement in areas with limited transmission capacity was carried out with and without consideration of wake effect.

The effect on curtailment cost due to availability of wind turbines is also investigated. The results have proven that with consideration of wake effect and availability potential wind energy curtailments are reduced and hence curtailment costs are lowered, making curtailment a cheaper option than grid reinforcement.

Index Terms–Modeling, Power system economics, Power transmission, Wind Energy, Wind power generation

I. INTRODUCTION

The best locations for building wind farms (WF) are usually in the remote areas with low population density. The transmission system in these areas, however, is generally not dimensioned to accommodate large-scale wind power plants. The thermal limits of the transmission lines or voltage stability issues (in case of most frequently used short and medium length transmission lines) typically limit power transmission capability during extreme situations (e.g. high load, high hydropower production during a spring flood etc.). One way to overcome these limits is grid reinforcement, i.e. building new transmission lines. This however, is not a viable option as it is subjected to various planning and environmental constraints and requires substantial investments and time.

Furthermore, under deregulated market conditions it is not clear how the investment costs should be divided between network operators and production utilities. Different countries use different approaches (deep, shallow, shallowish) when determining network connection costs.

Shallow connection costs approach (e.g., in Denmark and Germany) includes only the direct connection costs, i.e. the costs for new service lines to an existing network point and partially also the costs for the transformer that is needed to raise the voltage from the WF to the voltage of the distribution or transmission network. Necessary transmission or distribution network reinforcements are paid by network company and then equally divided between all network customers.

Deep connection charges (e.g. in Netherlands and in Spain on a distribution level) include the costs for new service lines to an existing network point, the costs for the transformer as well as part or all of the costs for necessary network reinforcements.

Shallowish connection charges is a combination of Deep and Shallow charges as the connection charges include a contribution to reinforcement costs based upon proportion of increased capacity required by a wind farm, e.g. UK [1].

The main disadvantage of shallow connection costs is that there is no incentive to build WF in the areas with available transmission capacity. Deep connection costs are not justified because they do not apply to conventional power plants or consumers and they might also lead to excessive and non-optimal grid reinforcements. The optimal balance therefore, should be found between extra benefits arising from increased transmission capacity and costs of respective network reinforcements. Normally it will not be optimal to remove a bottleneck completely.

One possible way to install large-scale WF without network reinforcement is to curtail excess wind energy during short periods of time when the power system is highly loaded. This alternative is currently used, e.g. in Spain where significant number of WFs located between Galicia and Madrid produce power below their full capacity since the necessary reinforcements of the transmission grid have not been realized yet [2].

In order to assess more realistically required wind curtailment in the presence of limited power transfer capacity the probabilistic estimation method of wind energy curtailment was proposed in [3]. It estimates expected wind energy curtailments for various wind power penetration levels and compares the curtailment costs with the costs of grid reinforcement. The method however does not include the wake effect and availability of wind turbines.

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This paper introduces improvements to the probabilistic estimation method of wind energy curtailment proposed in [3] by incorporating the influences of the wake and wind turbine availability in the estimation procedures.

II. WAKE EFFECT

Electricity is generated by the wind turbine driven generators in a similar way to that of hydro or coal fired plants except that in this case the wind (not water or steam) striking the blades mounted on the rotor of a wind turbine forces the generator shaft to rotate. The wind energy leaving the wind turbine has lost some of its content as part of it got transformed into kinetic energy of the rotor. Wind leaving the rotor is therefore, both, reduced in speed and turbulent. This wind behind the rotor is called a wake. An effect of wake includes reduced wind speed which causes reduction of power output for the downwind turbines. The turbulence in the wind can cause downwind turbines to be under additional mechanical stress, which may reduce their operating life. In order to reduce the effects of wake wind turbines should be spaced at least 5 to 9 rotor diameters (D) away from each other in the prevailing wind direction and about 3 to 5 rotor diameters for winds coming perpendicularly. If the wind turbines are placed between 4 and 8 rotor diameters from each other the power losses occurring due to wakes can be in the range of 5% to 15% of the total power produced by the wind farm [4]. Wake wind speed is calculated based on principle of momentum conservation. In the wake model used the aerial spread of momentum deficit is such that the radius of the wake increases linearly with the distance (see Fig. 1).

A. Wind Model

Considering wind direction in analysing wake effects is very important as different wind directions cause different types of wake effects. Wind turbines facing the wind (upwind turbines) are likely to receive more stable and consistent wind. The turbines at the back (downwind) receive wind which has reduced wind speeds and is more turbulent.

B. Wake Model

Many wake models have been proposed in the past [4]-[8]. The choice of the model depends on desired accuracy of prediction and on computational time. Some of the proposed models include Ainslie’s model [5], Frandsen’s model [6], Mosaic Tile model [7], Jensen’s model [8] and CFD (Computational Fluid Dynamics) models [4]-[9]. From comparison of different wake models, presented in [4], it can be observed that the sophisticated models have similar level of accuracy as simpler ones.

One of those simpler models, Jensen’s model [8], was selected for calculations of the wake in this study as it provides adequate accuracy and reduced computational time. It assumes that the wake downstream the turbine expands linearly. The model is graphically explained in the Fig. 1. The rotors of the turbines have radius \( r_o \) and the upwind turbine receives free-stream wind \( u \), having the thrust coefficient \( C_t \). After passing through the rotor disc the wind slows down to \( v_o \). The wind speed at a distance \( x_o \) from the turbine is \( v_j \).

The radius of the wake at distance \( x_o \) (location of downwind turbine) is \( r_w \). The radius of the wake disc increases linearly with the distance as:

\[
r_w = k \cdot x_o + r_o
\]

where \( k \) is the entrainment constant or opening angle which represents the effects of atmospheric stability. Jensen found experimentally the value of \( k \) to be 0.075 for onshore applications and 0.04 for offshore applications. The wake velocity at distance \( x_o \) is calculated as follows [10]:

\[
v_j = u \left[ 1 - \left( \frac{r_o}{r_o + k \cdot x_o} \right)^2 \cdot \left( 1 - \sqrt{1 - C_t} \right) \right]
\]

where \( v_j \) is the velocity of the wake at a distance \( x_o \), \( u \) is the free-stream wind velocity and \( C_t \) is the thrust coefficient of the rotor (based on incoming wind speed).

The wake downstream follows a top-hat distribution [8] which shows greater speed deficit in the middle of the wake while away from the centre, i.e. near the edges of the wake the deficit is the lowest.

C. Partial Shadowing

Partial shadowing is a phenomenon which occurs when one or more upwind wind turbines cast a ‘single’ shadow on a downwind turbine. The wind speed at the rotor disc of interest is then determined by calculating the ratio (weighting factor, \( \beta \)) of the rotor area in wake to the total rotor area. The wind speed entering into the turbine is given by (3)[11]:

\[
v_{Tj} = u \left( 1 - \sum_k \beta_{Tj,Tk} \left( 1 - \frac{v_{ps,Tk}}{u} \right) \right)
\]

where \( j \) is the wind turbine under wake, \( k \) is the upwind turbine, \( u \) is the initial wind speed entering into the wind turbine \( k \), \( v_{ps,Tk} \) is the shadow of \( k \) falling on wind turbine \( j \).
Partial shadowing is illustrated in Fig. 2 which shows the circular disc of wind turbine $j$ on which wakes of wind turbine 2 and 3 are falling. The radius of the wake of the wind turbine 2 and 3 is $r_{w,2}$ and $r_{w,3}$. These wind turbines are referred to as wind turbine $k$ in (3). Hence to compute the wind speed entering into the wind turbine $j$ the reduced wind speed from turbine 2 and 3 have to be calculated first according to their distance from turbine $j$, and then the area they overlap on the disc of turbine $j$.

**D. Multiple Wakes**

Multiple wakes occur when two or more upwind turbines slow down the wind approaching the turbine in the consecutive column. Fig. 3 illustrates the effect of multiple wakes on the third turbine from the left since it is in wake of the second turbine which in turn is in wake of the first one. It is shown in [12] that the effect of the first wake is the strongest, i.e. the wind speed reduction is the largest.

**E. Wind Roses**

In this study, the wind speed per turbine (for a symmetrical WF of 9 turbines) is evaluated taking into account rotor radius, thrust coefficient value ($C_t$), wake of wind turbine, partial shading and multiple wakes according to distance between the turbines.

Additionally, since the effect of wake on the wind turbine (WT) power output is associated with the incoming wind’s direction [13], the direction of wind is varied with resolution of $1^\circ$ (compared to $10^\circ$ reported in [10]).

The reduction in wake coefficient (i.e., the ratio of power output with the wake effect to the power output without wake effect) with the increase in wind speed for different directions of wind is shown in [13]. Similar results were obtained in this study but not included in the paper due to space limitation.

The following assumptions were made when calculating wind speed per turbine for winds from all directions as shown in Fig. 5:

- Top hat wind speed distribution of the wake is ignored, i.e. the wake wind speed is constant at given distance.
- For wind speeds lower than rated and above cut-in speed, the rotor’s angular speed will be adjusted by the controller. Above rated wind speed, the rotor speed will remain the same. These effects are assumed to have been taken into account in the $C_t$ values provided.
- The effect of upstream wind speed change, i.e. reduction of wind speed at downwind turbines, takes effect on the downwind turbines immediately. (Note: In reality there is some delay in this effect taking place due to the distance between the turbines.)
- Turbulence in the wind is neglected
For simplicity, let $X$ be the amount of power in MW transmitted through the bottleneck before wind power is installed. Let $Y$ correspond to expected wind power production in MW. $X$ and $Y$ are assumed to be discrete independent variables. The distribution function for transmitted power and corresponding probability density function are $F_X(x) = P(X \leq x)$, $f_X(x) = P(X = x)$, where $P(X = x)$ is the probability that transmission $X$ is less than or equal to a level $x$ and $P(X = x)$ is the probability that power transmission $X$ is exactly $x$. For the discrete case:

$$f_X(x) = P(X = x) = freq_X(x)/N$$

where $freq_X(x)$ is frequency of level $x$ MW, $N$ is number of measurements;

$$F_X(x) = P(X \leq x) = \sum_{i:X_i \leq x} f_X(x_i)$$

Similarly, distribution function and probability density function can be expressed for wind power output $Y$, $F_Y(y) = P(Y \leq y), f_Y(y) = P(Y = y)$. Using long-term wind speed measurements, the power output $Y$ of the planned WF can be obtained from the power curve of the WT. Then distribution and probability mass functions of $Y$ are calculated. Let’s now introduce the discrete variable $Z$, such that $Z = X + Y$. $Z$ is the desired transmission after wind power is installed in the area with the bottleneck problems. Its probability density function $f_Z(z)$ is obtained from the convolution expression as follows [15]:

$$f_Z(z) = \sum_{x} f_X(x)f_Y(z-x) = \sum_{y} f_X(z-y)f_Y(y)$$

The Distribution function of the discrete variable $Z$ is:

$$F_Z(z) = \sum_{i:Z_i = z} f_Z(z_i)$$

Fig. 7 illustrates the results of the discrete probabilistic estimation. As $F_Z(z) = P(Z \leq z)$, the value $1 - F_Z(C)$ in Fig. 7 corresponds to the probability that the transmission limit $C$ is exceeded. The area under $1 - F_Z(C \leq z < \infty)$ is equal to wind energy that should be spilled.

### A. Wind Turbine Availability

The method for deriving probability distribution function of WF production considering availability of WT is proposed in [16]. In this paper only a short overview of the method is provided for completeness of discussion.

For $K$ identical WTs within a WF each of which may fail, there are $K+1$ turbine availability states, where state 1 corresponds to 0 generators in service, state 2 corresponds to 1 generator in service and so on; thus state $K+1$ corresponds to all generators in service. The probability of each state depends on total number of wind turbines and availability of a single turbine [17]:

$$P_{WF}(k) = \frac{K!}{(K-k)!}p_{WT}^k(1-p_{WT})^{(K-k)}$$

where $p_{WT}$ is availability of a single WT.
In contrast to conventional generators, WT production depends on uncontrollable source - wind. Therefore WT is in certain capacity state $S_{WT}(v)$ at each wind speed $v$, 

$$S_{WT}(v) = 0.5 \cdot c_p \cdot A \rho v^3$$  \hspace{1cm} (10)$$

where $A$ is swept area of the wind turbine, $\rho$ is air density and $c_p$ is overall efficiency of WT.

Consequently, probability of each capacity state depends on probability of the corresponding wind speed. In [16] it was assumed that all WTs within a WF are identical and that all turbines within a WF are facing the same wind speed. The capacity states of the whole WF are thus calculated as number of turbines $K$ multiplied with each capacity state $S_{WT}(v)$ of single WT, i.e.

$$S_{WF} = K \cdot S_{WT}(v)$$  \hspace{1cm} (11)$$

WF capacity states, however, do not uniquely correspond to certain wind speed as WT capacity states, but can occur at several $(k, v)$ combinations, where $k$ is number of wind turbines in service and $v$ is wind speed. Combining probability density function of WF availability states (9) and probability of each WT capacity state the probability distribution function $F_y(y)$ for WF capacity states can be obtained (see [16] for details).

According to [18] availability of the WT varies between approx. 95% and 100% on yearly basis depending on weather conditions, age of WT etc. Fig. 8 illustrates wind power production distribution function considering 95%, 97%, 98% and 100% availability of the wind turbines within WF.

As it was shown in the preceding sections not all WTs within a wind farm meet the same wind. If wake effect is considered then power production of each wind turbine depends on its location within a wind farm, the wind speed, wind direction and also the location of unavailable wind turbines as this will affect the wake that neighboring turbines are experiencing.

For a WF consisting of $K$ wind turbines, this would result in $K!+1$ WF availability states (e.g. 362881 states for 9 WTs), combined with different production states based on wind speed and wind direction. There might be some symmetry depending on WF layout but still the task is enormous and will also depend on layout of each particular wind farm. On the other hand the refinement to the WF probability distribution function from WT availability consideration is relatively small.

In order to resolve the trade off between dimensionality and accuracy the following simplification is introduced. WF production is calculated for each wind speed and direction considering wake effect. The results of this calculation are shown in Fig. 9. Dividing the total WF production by the number of WTs in a wind farm, equivalent WT power curve can be obtained for given WF layout. It is assumed then that for any given wind speed and direction the power production of all WTs within a wind farm is the same. The amount of power that each WT within the farm is producing, is obtained from the equivalent WT power curve developed previously considering the wake effect. The impact of the wake is thus effectively averaged out among all wind turbines in a wind farm.
Wind power production of the wind farm is calculated using 10-minute average wind speed and direction measurements from the site Sourva in northern Sweden (additional information about this site is available in [19] and [20]). These wind measurements are converted to power using the power curve of Vestas V80 wind turbine [21] and considering the wake effect model presented above.

Fig. 10 illustrates a wind rose for the site characterized by two prevailing wind directions.

Some of the results for probabilistic estimation method were already presented in Fig. 7. The figure indicates the probability that transmission limit is exceeded as well as potential energy curtailments, for the cases where WT availability is assumed to be 100%. The area under $1 - F_Z(C < z < \infty)$ is equal to wind energy that should be curtailed. For the case with 100% WT availability the curtailed wind energy is equal to 9.45% of total wind energy production during the studied period, which corresponds to 4484.6 MWh/year.

Fig. 11 shows probability density function of wind power production for each WT within the WF. It can be seen that for each production state (particular generated power, e.g. 1MW) the probabilities that each WT within a WF is in this production state are relatively close. This can be explained by symmetric layout of the wind farm and two opposite prevailing wind directions. The simplification related to WT availability calculation considering wake effect introduced above is thus fully applicable for this site and WF layout.

### IV. CASE STUDY

The estimation method presented above is applied to a case study, where a WF is developed in an area with good wind potential. There are other generators situated in the same area as well as local electricity demand. Transmission capacity from this area is limited to 70 MW.

Throughout a year the power transmission through the aforementioned corridor varies with load. For about 4000 hours per year the loading is less than 55% of total transmission capacity. The wind farm consists of 9 wind turbines and has a rated power of 18 MW. The distance between turbines in the same row and column is about 400m. The wind turbines are horizontal axis pitch regulated upwind turbines with active yaw system. The turbines used are Vestas V80 with OptiSpeed™ and OptiTip® technology having asynchronous generator with rated power of 2 MW. Rotor radius of a WT is 40 m and hub height is 80 m above the ground.

There is, however, not enough transmission capacity to guarantee power transmission from the wind farm through the transmission corridor during 100% of the time during the year. The probabilistic estimation method is thus applied to weigh the costs of expected wind energy curtailments against the costs for necessary grid reinforcement.

#### A. Results of the Analysis

The power flow on the other transmission lines is, for simplicity, assumed unaffected by wind power integration.
Fig. 12 shows the combined effect of wind turbine availability and wake effect on wind energy curtailments. It can be seen that the difference between the amounts of wind energy curtailment required with and without wake effect is about 350 MWh per year. This shows that taking into account wake effect reduces effectively the cost of curtailment.

In discrete probabilistic method applied here the wind power production and power transmission (without wind power) are assumed to be independent variables. According to the available data, the correlation between the wind speed and transmission was -0.06, which justifies the assumption made.

V. EFFECT ON COST OF CURTAILMENT DUE TO CONSIDERATION OF WAKE AND AVAILABILITY

In Fig. 13 curtailed wind energy from Fig. 12 is expressed in £M/year, assuming electricity tariff of 5.45p/kWh [22]. If neither wake effect nor availability are considered, the costs for energy curtailments are £0.245M/year. Sole consideration of wake effect reduces the estimated costs of curtailments by about £0.019M/year. Since lifetime of a wind farm is about 25 years this could in total cost reduction of about £475k over the life time of the WF (reduction of 7.76% compared to reference curtailment costs, see Table 1).

According to Fig. 13 if wake effect and availability of wind turbines (97%) are considered the estimated costs for energy curtailments will be reduced to £0.216M/year. This results in total cost reduction of £725k over the lifetime of the wind farm (reduction of 11.84% compared to reference curtailment costs, see Table 1).

Table 1 summarises the results obtained by taking into account different levels of detail in wind energy curtailment calculations. The results are shown as costs for energy curtailments per year as well as total costs over WF lifetime, i.e. 25 years. Total costs to be incurred over 25 years are compared to the reference case, i.e. when neither wake nor WT availability are included in wind energy curtailment calculation. Finally the results are compared to the costs of the new 33 kV line (calculated over WF life time).

Table 1 summarizes the results obtained by taking into account different levels of detail in wind energy curtailment calculations. The results are shown as costs for energy curtailments per year as well as total costs over WF lifetime, i.e. 25 years. Total costs to be incurred over 25 years are compared to the reference case, i.e. when neither wake nor WT availability are included in wind energy curtailment calculation. Finally the results are compared to the costs of the new 33 kV line (calculated over WF lifetime).

<table>
<thead>
<tr>
<th></th>
<th>Without wake, without availability</th>
<th>Without wake, with 97% availability</th>
<th>With wake, without availability</th>
<th>With wake, with 97% availability</th>
</tr>
</thead>
<tbody>
<tr>
<td>Per year</td>
<td>0.245</td>
<td>0.238</td>
<td>0.226</td>
<td>0.216</td>
</tr>
<tr>
<td>Cumulative, (over 25 years)</td>
<td>6.125</td>
<td>5.950</td>
<td>5.650</td>
<td>5.400</td>
</tr>
<tr>
<td>Difference compared to reference case (over 25 years)</td>
<td>Reference case (-2.86%)</td>
<td>0.475 (-7.76%)</td>
<td>0.725 (-11.84%)</td>
<td></td>
</tr>
<tr>
<td>Difference between reinforcement and curtailment costs (over 25 years)</td>
<td>2.315 (8.47%)</td>
<td>2.511 (21.08%)</td>
<td>2.803 (32.1%)</td>
<td>3.058 (32.1%)</td>
</tr>
</tbody>
</table>

The table clearly illustrates the difference in curtailment costs due to consideration of wake effect and availability of wind turbines. If the effects of wake and availability are included in wind energy curtailment calculations then curtailments can be £3.058M cheaper solution (over the lifetime of the WF) than building a new 33 kV line. This represents 32.1% increase in savings compared to the case when wake effect and availability were not included in calculations.

If the wake effect alone is taken into account the wind curtailments can be £2.803M cheaper solution than building
a new 33 kV line which represents over 20% increase in savings compared to the case when wake effect was not included in calculations.

VI. CONCLUSIONS

The paper investigated potential economic implications of inclusion of wake effect in assessment of wind farm power output. The results of the analysis first confirmed that wind farm topology plays an important role in prediction of total power output when wind direction, and consequently wake, is considered. Wind turbines facing wind directly produce more power than those affected by the wake of upwind turbines.

The economic significance of consideration of wake phenomenon was investigated by analysing a case where power produced by wind farm exceeds available transmission capacity; therefore, extra wind power had to be curtailed or grid reinforcement introduced. Both measures usually cost significant amount of money hence a comparison of cost was performed to help decide which option is more suitable. Comparison of grid reinforcement and wind energy curtailment measures is usually performed in prefeasibility stage of a WF development. Wake effect is often neglected in this comparison which leads to inaccurate decision. The effect of availability of wind turbines with and without wake effect consideration was also investigated to make the case more realistic. In simple test case studied in the paper, the consideration of wake effect and availability resulted in less curtailed wind energy compared to a case where these factors were neglected. The overall cost of wind energy curtailment was reduced making curtailments a cheaper option compared to grid reinforcement.

VII. REFERENCES


VIII. BIOGRAPHIES

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