Multi-Market Price Forecasting in Hydro-Thermal Power Systems

Arild Helseth, Mari Haugen, Stefan Jaehnert, Birger Mo
SINTEF Energy Research
Trondheim, Norway
arild.helseth@sintef.no

Hossein Farahmand, Christian Naversen
Department of Electric Power Engineering
Norwegian University of Science and Technology (NTNU)
Trondheim, Norway

***Abstract*—This paper presents a framework for price forecasting in hydro-thermal power systems. The framework consists of a long-term strategic and a short-term operational model. The strategic model provides the end-of-horizon valuation of water in hydro storages as input to the operational model. We emphasize on the operational model, and discuss work in progress to facilitate more detailed fundamental market modeling to enable realistic multi-market price forecasting. A case study of the Nordic power system demonstrates the use of the framework, quantifying the impact of constraints on cable ramping and reserve capacity on prices.**

I. Introduction

The European power market is in transition, both in terms of the generation portfolio and the market architecture. Binding targets exist for renewable power generation in the future, as well as policies to decommission nuclear generation capacity. Thus, the overall share of intermittent generation will continue to grow, and consequently, the need for flexibility and controllability both in production and demand will increase.

New cables are under construction from Norway to Great Britain and the European continent. In order to achieve further coordination of European power markets, deeper integration with respect to balancing services and security of supply is a priority. A possible long-term strategy for Europe is to utilize Norwegian hydropower reservoirs and generation capacity as an energy storage that supplies a share of the needed balancing services. This can reduce the cost of transition towards a low-carbon European power system. An expected consequence for the Nordic power system will be more volatile prices and larger volumes in balancing markets. In this context, system operators and producers need consistent long-term *price forecasts* for several electricity products to make robust and correct investment decisions, e.g. related to building new cables to the European continent and upgrading and expanding the hydropower system.

Price forecasting by system simulation has been the adopted practice for many players in the Nordic market [1]. A primary challenge in fundamental hydro-thermal market models is to find the marginal value of hydro resources. Due to the long-term reservoir storage constraints and uncertainty in inflow in hydropower dominated systems, the resource scheduling should be done for a sufficiently long time period and with an appropriate representation of uncertainties (inflow to reservoirs, wind power generation, temperature-dependent demand, etc.). Typically, fundamental market models for hydro-thermal systems only concern the product energy, assume that all uncertainty is revealed in weekly steps, and that all functional relationships are linear, see e.g. [2].

Rapid and unpredictable fluctuations in intermittent generation from renewable energy sources will offer new possibilities for controllable generation, such as hydropower, to help the system responding to these fluctuations. Hydropower plant operators will to a larger extent maximize their profit by producing at maximum at demand peaks and running at low efficiency in low-demand periods to sell fast-responding reserves. Thus, in an expected future with larger shares of renewable and intermittent generation, the design of fundamental hydro-thermal market models should be re-visited.

Several approaches for system studies and price forecasting considering multiple electricity products has appeared in the literature. The WILMAR toolchain combines a short-term multi-market model [3] with a long-term model [4] to address the importance of both short-term uncertainty (in wind and demand) and long-term dynamics in hydro storages. A similar approach is presented in [5] focusing on uncertainty in wind and transmission grid bottlenecks. In [6] a regulating power market model for northern Europe was developed and coupled to a fundamental hydro-thermal market model. The regulating power market model includes reserve procurement as well as real-time system balancing, estimating the marginal cost of reserve capacity and balancing energy. A separate procurement of operating reserves ahead of the spot-market is studied in [7], using estimates of the spot market outcome to determine bids for upward and downward reserves. In [8] a model chain combining simulations of the European power market and the detailed German system is described. The model chain was used for price forecasting in both the day-ahead and reserve markets in [9], obtaining market prices through multipliers obtained in a Lagrangian relaxation procedure. A different model for the German market is presented in [10], obtaining reserve capacity prices by evaluating the opportunity costs.

In this work we describe a framework for fundamental price forecasting in hydro-thermal power markets. Compared with the above-mentioned approaches, we focus on providing a

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flexible framework representing the hydropower system with a high degree of detail. We describe the basic framework design, including the coupling between an existing long-term hydro-thermal scheduling model [11] and a new and flexible short-term fundamental price forecasting model. The framework is under construction, and we outline research and development in progress. Thus, this work can be seen as a first-step towards a more comprehensive framework for multi-market price forecasting in hydro-thermal systems.

II. Price Forecasting Framework

The framework consists of two modeling layers and the coupling between them. We believe that the computational complexity of the multi-market hydro-thermal scheduling problem prohibits the use of one single model, and have therefore decomposed the problem into a strategic and an operational model. This decomposition allows us to include more modelling details at a finer time-resolution in the operational model. First, a long-term strategic model is run to find the expected marginal values of water in hydro reservoirs, represented by Benders cuts, as illustrated in Fig. 1. Subsequently, these cuts serve as end-of-horizon valuation of water in a short-term operational model, as illustrated in Fig. 2. The two models are described in the following. The operational model is built in the open-source and Python-based optimization modeling language Pyomo [12]. By using a high-level modeling language we allow flexibility in experimenting with the problem formulation. Moreover, we use Python to facilitate a flexible environment for reading input data, communicating with Pyomo and interpreting results.

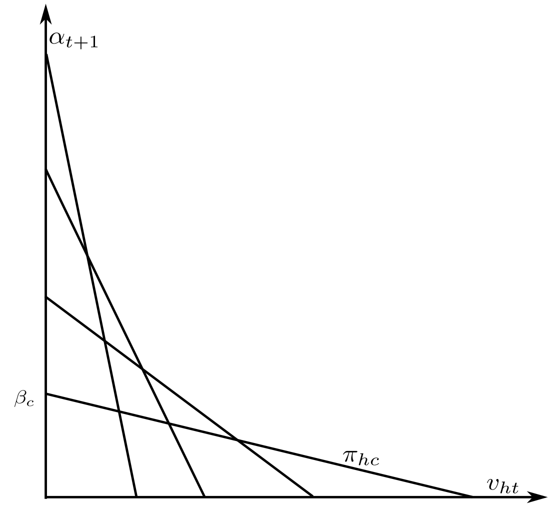

Fig. 1. Illustration of Benders cuts generated by the strategic model.

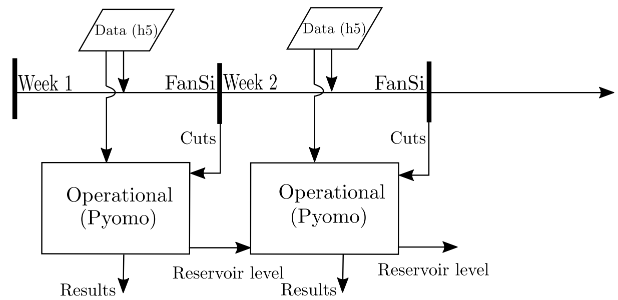

Fig. 2. Coupling between the strategic FanSi model and the operational model.

A. Strategic Model

The strategic model solves the long-term hydro-thermal scheduling problem. The problem is dynamic due to the couplings in reservoir storages between the stage-wise decisions in the scheduling problem. Operating decisions made in the current stage will affect the reservoir levels in the next stage. Furthermore, the problem is stochastic since uncertainty about the future will affect the decisions made today. Normally uncertainties are related to weather (typically inflow, snow, temperature, wind and solar radiation) and exogenous power prices. For the Nordic system, with more than 1000 hydro reservoirs and covering a widespread and climatically diverse geographic region, the problem is of high dimensionality both in terms of reservoirs and stochastic processes [2].

We apply the Scenario Fan Simulator (FanSi) model described in [11] as the strategic model. In the FanSi model, decisions for each week are determined by solving a two-stage stochastic linear programming problem considering uncertainty in weather and exogenous power prices. Uncertainties are represented by a fan of scenarios. The overall scheduling problem is solved by embedding such two-stage problems in a rolling horizon simulator, see [11] for more details.

From the strategic model one obtains a set of Benders cuts $\mathcal{C}_t$ for each week t describing the expected future cost α_{t+1} of operating the system seen from the next week $t+1$ as a function of the hydro storage levels for all reservoirs $v_{ht}, h \in \mathcal{H}$ at the end of week t. This functional relationship is illustrated in Fig. 1 for one reservoir. When considering multiple reservoirs, the Benders cuts becomes multi-dimensional, as described in (1).

$$\alpha_{t+1} + \sum_{h \in \mathcal{H}} \pi_{hc} v_{ht} \geq \beta_c, \quad \forall c \in \mathcal{C}_t \tag{1}$$

B. Operational Model

An operational model was constructed to re-optimize the weekly decision problem using a finer time resolution and with more detailed modeling. For each week, system data is read using the same data sources as was used in the FanSi model. Thus, the weather data and the basic system description corresponds with those used in the FanSi model. At the end of the week water is valuated according to the Benders cuts (1) obtained from the FanSi model, as illustrated in Fig. 2. Having solved the operational problem for one week, we store the results and pass the reservoir storage levels at the end of week forward as a starting point for the next week. This re-optimization procedure is repeated for all weeks to be simulated, as illustrated in Fig. 2.

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III. Weekly Operational Problem

In this section we first formulate a basic variant of the weekly operational problem which is to a large degree similar to the formulation in the FanSi model in [11]. Subsequently, we outline work in progress associated with improving and re-shaping the basic model, and describe new constraints that are further analyzed in the case study.

A. Basic Operational Model

In the following we formulate the optimization problem which is solved for each simulated week in the operational model. We consider a set of $\mathcal{A}$ price zones and $\mathcal{M}$ exogenous market areas being simulated using $\mathcal{K}$ time steps within the week. In this work we use hourly time resolution, so that $|\mathcal{K}| = 168$. Units are in MW (power), Mm^3 (water) and 10^3 € (costs), and all costs are denoted C. The model is formulated as a deterministic linear programming (LP) problem.

Minimize:

$$Z_t = \sum_{k\in\mathcal{K}} \left(\sum_{a\in\mathcal{A}} \sum_{g\in\mathcal{G}_a} C^G_{gk} y^G_{gk} - \sum_{d\in\mathcal{D}_a} C^D_{dk} y^D_{dk} + C^R r_{ak} + \sum_{m\in\mathcal{M}} \lambda_{mk} \left(y^P_{mk} - y^S_{mk} \right) \right) + \alpha_{t+1} \quad (2)$$

Subject to:

$$v_{hk} + \sum_{n\in\mathcal{N}_h} q^D_{nhk} + q^B_{hk} + q^S_{hk} + \sum_{p\in\mathcal{P}_a} \psi_{ph} q^P_{hk} - \sum_{j\in\omega^D_h} \sum_{n\in\mathcal{N}_j} q^D_{njk} - \sum_{j\in\omega^B_h} q^B_{jk} - \sum_{j\in\omega^S_h} q^S_{jk} - v_{h,k-1} = I_{hk} \quad \forall h, k \quad (3)$$

$$\sum_{g\in\mathcal{G}_a} y^G_{gk} + \sum_{h\in\mathcal{H}_a} \left(\sum_{n\in\mathcal{N}_h} \eta_{nh} q^D_{nhk} - \sum_{\substack{p\in\mathcal{P}_a \\ \psi_{ph}=1}} \eta_p q^P_{hk} \right) - \sum_{d\in\mathcal{D}_a} y^D_{dk} + \sum_{\substack{\ell:(a,b) \\ \in\mathcal{L}_a}} \left[(1-\zeta_\ell) f_{bak} - f_{abk} \right] + r_{ak} - d_{ak} = D_{ak} - P_{ak} \qquad \forall a, k \quad (4)$$

$$y^P_{mk} - y^S_{mk} + \sum_{\substack{\ell:(m,a) \\ \in\mathcal{L}_m}} \left[(1-\zeta_\ell) f_{amk} - f_{mak} \right] = 0 \quad \forall m, k \quad (5)$$

$$\alpha_{t+1} + \sum_{h\in\mathcal{H}} \pi_{hc} v_{hk} \geq \beta_c \qquad k = |\mathcal{K}|, \forall c \in \mathcal{C}_t \quad (6)$$

The objective (2) is to minimize the system costs associated with operation of the system in the current decision period and the expected cost of operating the system in the future. The current cost comes from thermal generation y^G, curtailment of price-inelastic demand r, and purchase of power from exogenous markets y^P. Meeting the price-elastic demand y^D and selling power to exogenous markets y^S can be seen as revenues. Import and export across the system boundary is modeled by a sales and purchase option at the price λ_{mk} towards exogenous market areas. The future expected operating cost is represented by α_{t+1} which is constrained by Benders cuts in (6).

The hydropower system comprises hydropower *modules* $h \in \mathcal{H}$ connected through the three waterways discharge q^D, bypass q^B and spillage q^S. A module comprises one reservoir and one power station, and has a set of upstream modules ω_h from which it receives water through one or more of the waterways. Water balances in (3) are defined for each module in each time step, balancing the reservoir content while accounting for the inflow I and the usage of the waterways and pumps q^P. ψ is a pump topology indicator (taking a value 1 or -1 if pumping from or to reservoir h, respectively).

Power balances for each price zone and exogenous market area in each time step are provided in (4) and (5), respectively. Thermal and hydro generation are scheduled to meet the demand D subtracted the wind power P, while allowing exchange f with neighboring price zones and exogenous markets. The transmission system connecting zones and markets in (4) and (5) is represented by limiting flows through maximum flow capacities. $\mathcal{L}_a$ is a set of connections associated with price zone a. We let the transmission losses depend linearly on the flows by a fraction ζ_ℓ. The hydropower generation in (4) is modeled as a piecewise-linear and concave relationship between power and discharge, provided that the efficiencies η_{nh} decrease with increasing efficiency-curve step number n. The pump efficiency is denoted η_p.

All variables are non-negative and may have time-dependent lower and upper boundaries. The reservoir, discharge and bypass variables are often subject to seasonal constraints to ensure that watercourses are operated in a sustainable manner.

B. Future Model Extensions

The basic operational model presented in Section III-A is based on three assumptions that we believe should be challenged when forecasting prices in the future Nordic power market:

1) It only concerns the product *energy*. The procurement of reserve capacity and activation of balancing energy is not considered.
2) It is *deterministic* within the week, and therefore has the ability to clear the market simultaneously for all time steps according to known parameters for the whole week.
3) It is based on *linear programming*. Thus, it can at best approximate binary decisions and nonconvexities, such as start-stop of generating units and nonconvex hydropower production functions.

In addition the basic operational model will tend to overestimate the flexibility in the generation and transmission

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system, lacking constraints on e.g. ramping and time-delays in water courses. On the other hand it will tend to underestimate the flexibility on the consumer-side, as demand response and integration of local storages are expected to impact the future market.

By using the presented framework we intend to gradually challenge all of these assumptions in our future work. As a first step, we wanted to test the impact of ramping constraints on cables between exogenous markets and price zones. These are added in (7), limiting the maximum change in flow between two consecutive time steps to Δ_ℓ.

$$-\Delta_\ell \leq \left(f_{amk} + f_{mak}\right) - \left(f_{am,k-1} + f_{ma,k-1}\right) \leq \Delta_\ell \quad (7)$$
$$\forall a \quad \ell : (a,m) \in \mathcal{L}_m$$

Furthermore, we added reserve requirements R^+ and R^- for up- and down-regulation for a set of areas $\mathcal{A}_H$ in (8) and (9), respectively. $\bar{P}$ is the maximum allowed power output from a station. We included these constraints to test the ability of the hydropower system in certain areas to deliver reserve capacity, and to study the resulting power and reserve capacity prices. Note that we do not consider start-up costs and a minimum output from each station, and thus will tend to overestimate the flexibility (and underestimate the cost) of the hydropower system to deliver down-regulating reserves. These features can at best be approximated in a linear model, as discussed in [13].

$$\sum_{h \in \mathcal{H}_a} \left(\bar{P}_h - \sum_{n \in \mathcal{N}_h} \eta_{nh} q^D_{nhk} \right) \geq R^+_a \quad \forall a \in \mathcal{A}_H \qquad (8)$$

$$\sum_{h \in \mathcal{H}_a} \left(\sum_{n \in \mathcal{N}_h} \eta_{nh} q^D_{nhk} \right) \geq R^-_a \quad \forall a \in \mathcal{A}_H \qquad (9)$$

IV. Case Study

A. Case Description

The proposed framework was tested on data for the Nordic system, see illustration in Fig. 3. The system description comprises 23 price zones; 12 in Norway, 6 in Sweden, 2 in Denmark, 3 in Finland, and represent a possible system configuration around year 2020, including HVDC cables to the exogenous markets in the Netherlands, Germany, Poland and the Baltics.

In the FanSi simulations we considered the historical inflow years 1961-1990 represented by 85 geographically unique inflow records, most with daily and some with weekly resolution. Wind power and temperature data with weekly time resolution were specified for the same sequence of years using 15 and 6 individual records, respectively. Exogenous market prices on hourly time resolution were used. The system was modeled using 1108 hydro modules (each module has a hydro reservoir and a power station).

The FanSi model was used to obtain Benders cuts to be used in the operational model, according to the illustration in Fig. 2. We ran the operational model for one selected weather year using hourly time resolution. The 3 cases studied are listed in Table I. In case B we introduced a ramping rate of 600 MW/hour for all cables towards exogenous markets, in line with the current practice in the Nordic market [14]. In case C we assumed a symmetric reserve requirement of 4000 MW distributed to each price zone according to the sum of hydropower generation capacity within the zone. The total hydropower capacity in the modeled system is 52886 MW.

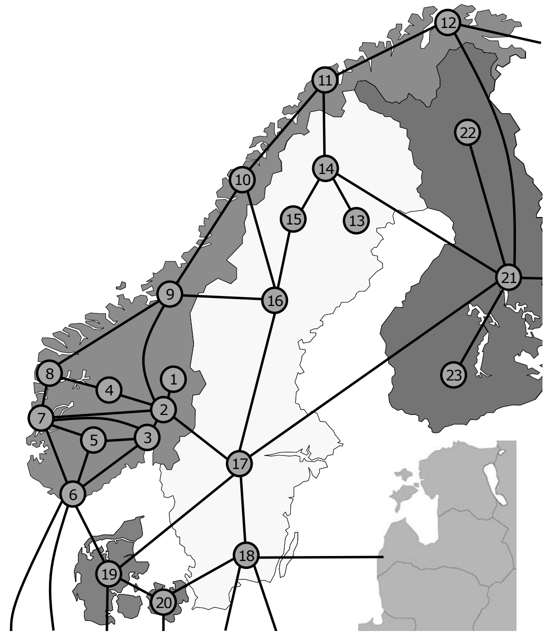

Fig. 3. Illustration of case.

TABLE I
SIMULATED CASES.

Case	Description	Constraints
A	Base	(3)-(6)
B	Base+Ramping	(3)-(7)
C	Base+Reserve	(3)-(6)+(8)-(9)

B. Results

The ramping rate constraints introduced in case B significantly limit the ability of the Nordic system to change from full import to full export (or the other way around) in two consecutive hours. In Fig. 4 we show the simulated power prices, i.e., the dual values of (4), for price area 6 in southern Norway with cable connections to the Netherlands, Germany and Denmark. The figure shows that prices from case B have a lower spread than those from case A. The ramping constraints serve to dilute the price signal from the exogenous markets. This effect is most pronounced on the down-side, indicating that the ramping constraints limiting increased import (or reduced export) to area 6 are the most binding.

The prices for down-regulation capacity, i.e., the dual values of (9), obtained from case C for price areas 2, 7 and 13 are

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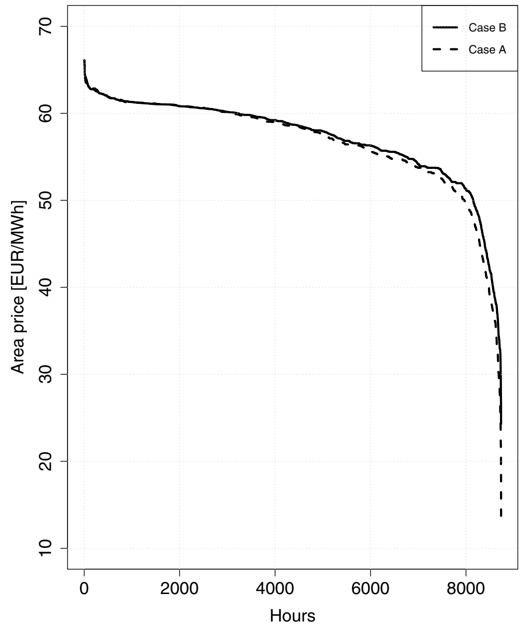

Fig. 4. Duration curves for power prices in area 6 for case A and B.

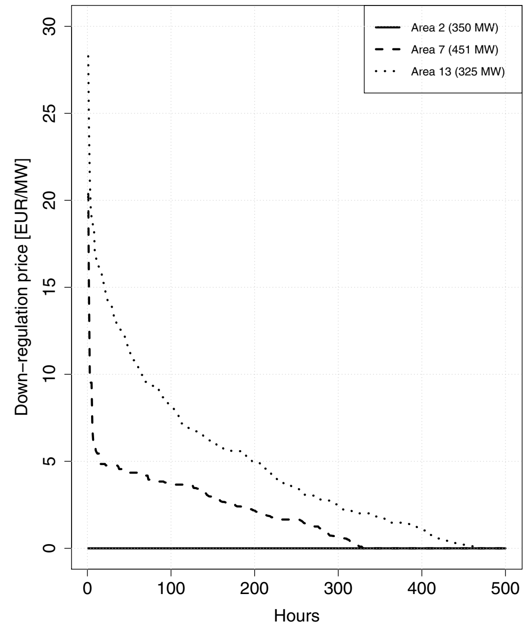

Fig. 5. Duration curves for down-regulation prices for areas 2, 7 and 13 obtained from case C. Zonal reserve requirements are stated in parenthesis.

sorted in decreasing order in Fig. 5. The area requirements for down-regulation capacity are stated in the figure. Ensuring the availability of sufficient down-regulation capacity is most challenging at summer time, forcing generators that would normally shut-down to operate at low energy prices to deliver reserves. Fig. 5 indicates that this is more of a problem in hydro-dominated price areas with a high degree of regulation (such as areas 7 and 13) compared to those areas with significant amounts of run-of-river hydropower (such as area 2).

V. Conclusion

We presented a framework for price forecasting in hydro-thermal power systems and discussed work in progress to facilitate more detailed fundamental market modeling to enable realistic multi-market price forecasting. A case study of the Nordic power system demonstrates the use of the framework, quantifying the impact of constraints on cable ramping and reserve capacity on prices. In our further work we plan on extending the operational model to include more technical and market-related details, and open for multiple decision sequences within the week.

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