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Implementing hydropower scheduling in a European expansion planning model

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Abstract

A method for implementing an enhanced hydropower planning formulation in a long-term expansion planning model is proposed. The methodological framework involves assigning hydropower generation a marginal cost through water values, enabling comparability with the marginal costs of competitive technologies. Added robustness and details in the representation of hydropower and its inherent storage capabilities allows for a more precise evaluation of the technology's impact on optimal investments for other power resources. The impact for intermittent renewable energy sources such as wind and solar power is especially interesting to analyze. Examination of effects from the richer formulation is carried out for an EU 20-20-20 like policy scenario. Optimization results for Europe in the period 2010 to 2060 show that the new framework leads to decreased utilization of hydropower due to its more precise valuation through water values, as well as lower inflow for run-of-the-river hydropower than previously. Therefore, additional investments are carried out for other energy sources that are deemed more economically beneficial. Notably, an earlier deployment of solar power is part of the revamped investment scheme.

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Keywords: Hydropower; emission reduction policy; GEP; generation planning; optimization

1. Introduction

The goal of generating enough energy to sustain the rapidly increasing global population, while simultaneously minimizing environmental impacts associated with energy extraction and consumption is a global pursuit of supreme importance. Models have been developed to analyze how this goal can be met at lowest possible cost. One

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of these is the EMPIRE[†] model, which is a European power investment model capable of incorporating various climate policy scenarios. Its framework is the starting point for the work presented in this paper, which consists of improving how hydropower is formulated in EMPIRE. One of the main objectives for doing so is to enable a more precise analysis of synergetic effects between installments of hydropower and intermittent renewables. The ongoing and future large-scale implementation of such variable generation introduces additional fluctuations in the power system and thereby new challenges in the continuous balancing of supply and demand [1]. Regulated hydropower can respond more or less immediately to fluctuations and can act as an ancillary service that regains balance in the power system [2]. This way, hydropower may support further investments in intermittent renewables.

Nomenclature

SYMBOL	DESCRIPTION	SYMBOL	DESCRIPTION
Sets and indices		**Parameters cont.**	
G g	Generators	$F^{init}_{ns\omega}$	Initial reservoir fraction of full reservoir
H h	Operational hours: H_s in a season, H_i in a year	$R^{init}_{ns\omega}$	Initial reservoir level [MWh]
I i	Years	R^{max}_{n}, R^{min}_{n}	Max. and min. reservoir level [MWh]
L l	Transmission lines	$R^{temp}_{ns\omega}$	Temporary reservoir level [MWh]
M_n m	Reservoir segments	$U^{Reg,norm}_{ns\omega}$	Seasonal normalized inflow [MWh]
N n	Nodes (one per country)	$U^{Reg,init}_{ns\omega}$	Seasonal inflow in 2010 (initial) [MWh]
S s	Seasons	$U^{RoR,norm}_{ns\omega}$	Seasonal run-of-the-river inflow [MWh]
Ω ω	Stochastic scenarios	S^{max}_{mn}	Maximum reservoir segment size [MWh]
Decision variables		$xd^{max}_{mns\omega}$	Actual reservoir segment size [MWh]
$xd_{mnsi\omega}$	Segmental discharge [MWh]	$WV_{mnsi\omega}$	Water value [$/MWh]
$r_{nsi\omega}$	End-of-season reservoir level [MWh]	α_h	Operational hour scale factor
$s_{nsi\omega}$	Spillage [MWh]	ϑ_s	Seasonal scale factor
p^{gen}_{gi}	Generation capacity [MW]	δ_i	Discount factor
x^{gen}_{gi}	Gen. capacity investment [MW]	ν_s	Number of hours in season
x^{tran}_{li}	Line capacity investment [MW]	p_ω	Scenario probability
$y^{gen}_{ghi\omega}$	Generation [MWh]	c^{gen}_{gi}	Generator investment cost [$/MW]
$y^{LL}_{nhi\omega}$	Load shedding [MWh]	c^{tran}_{li}	Transmission investment cost [$/MW]
Parameters		q^{gen}_{gi}	Generator short-run marginal cost [$/MWh]
N^{seg}	Number of segments in reservoir	q^{VoLL}_{ni}	Cost of using load shedding [$/MWh]

1.1. Related literature

There exist a vast number of optimization models used for investment planning and policy studies in Europe. Recent notable examples of linear programming models, where new generation and transmission investments are co-optimized with a system dispatch, are presented in [3] and [4]. The former model has since been adapted to detailed studies of long-term grid extensions in Europe, see [5], and a study of decarbonization of the European power sector, see [6]. In [7] a dedicated hydropower scheduling model is used to compute water values for seasonal

[†] **E**uropean **M**odel for **P**ower system **I**nvestment with (high shares of) **R**enewable **E**nergy

hydropower reservoirs, which are consequently used in a detailed DC load flow model of Northern Europe. This is similar to what has been done in this paper, although in this setting we focus on long-term system expansion.

1.2. Brief overview of the EMPIRE model

The purpose of the EMPIRE model is to provide a long-term plan for timing, size and location of investments in generation capacity and inter-country transmission capacity in Europe. This is done through cost minimization in the period 2010 to 2060, subject to various policy scenarios. EMPIRE is formulated as a linear, two-stage stochastic optimization model and has been implemented in Mosel Xpress [8]. The spatial resolution of EMPIRE is based on country-wise aggregation where each country represents a node n in the system. Investments can take place in 5-year leaps. Each year i is modeled as 10 non-consecutive seasons s, constituted by a number of operational hours h in which load balances are requested. Stochastic scenarios ω account for uncertainty related to some parameters such as load and generation from intermittent energy sources. Generation capacities, annual build limits and a number of other restrictions are included. For more information about the EMPIRE model, see [9]. In the next chapter, the strategy for improving the hydropower framework will be described.

2. Hydropower scheduling methodology

Regulated and run-of-the-river hydropower are modeled independently. In the original EMPIRE model, regulated hydropower availability comes at no cost, aside from low operation and maintenance costs. Thus, the model will tend to empty the reservoirs towards the end of each season, since the water is virtually free. This is a major simplification of real-world conditions, where the use of water values as marginal cost for hydropower generation is a widespread means of assigning monetary values to the available water resources. The water value can be defined as the future expected value of the stored marginal kWh of water, i.e. its alternative cost [10]. Therefore, it will generally be optimal to generate power from a unit of water whenever the water value is lower than the expected power price, or save the unit in the opposite case. This introduces the significance of saving water to other periods of the year, which is not present in the original EMPIRE model. Since seasons are modeled individually, the original formulation has no incentive to conserve water for later periods. The use of water values is one method of enabling this water-saving feature, and is the key concept of the improvement strategy we propose.

The methodology starts by dividing each reservoir into M segments of equal size, and each of these segments are given an associated water value. In the start of each season we set an initial reservoir level based on a fractional value of a full reservoir. Inflow to the reservoir is assumed to take place immediately in the beginning of a season, which can be justified by the short season durations in the model. As the reservoir level is reduced the water values increase, since the water becomes more valuable as the available amount decreases. When assuming that the lowest index number indicates the top-most reservoir segment, the inequality $WV_0 < WV_1 < \ldots < WV_{m-1} < WV_m$ must therefore hold for all segments $m \in M$.

2.1. Mathematical formulation

In this section we describe the mathematical framework for enhanced hydropower. The implementation of hydropower scheduling is done in two separate steps. The first step utilizes reservoir data to determine the available amount of energy in each reservoir segment, setting the bounds for segmental discharge. The second step includes restrictions for generation and reservoirs, and is given in the following. Reservoir discharge is connected with hydropower generation as

$$\sum_{h \in H_s} y^{gen}_{ghi\omega} = \sum_{m \in M_n} xd_{mnsi\omega}, \quad n \in N, g \in G_n^{HydReg}, s \in S, i \in I, \omega \in \Omega \tag{1}$$

It is necessary to keep track of the reservoir level at the end of each season. The end-of-season reservoir level is equal to initial reservoir level plus inflow minus total segmental discharge and spillage. This is shown in Eq. (2), while minimum and maximum reservoir levels are shown in Eq. (3):

$$r_{nsi\omega} = R_{ns\omega}^{init} - \sum_{m \in M_n} xd_{mnsi\omega} + U_{ns\omega}^{Reg,norm} \cdot p_{gi}^{gen} - s_{nsi\omega}, \quad n \in N, g \in G_n^{HydReg}, s \in S, i \in I, \omega \in \Omega \tag{2}$$

$$R_n^{min} \le r_{nsi\omega} \le R_n^{max}, \quad n \in N, s \in S, i \in I, \omega \in \Omega \tag{3}$$

The multiplication of installed capacity in the inflow term of Eq. (2) is done because we assume that changes in capacity also influence the available amount of inflow. Segmental discharge bounds are represented as follows:

$$xd_{mnsi\omega} \le xd_{mns\omega}^{max}, \quad m \in M_n, n \in N, s \in S, i \in I, \omega \in \Omega \tag{4}$$

For some nodes with small reservoirs and thereby a low degree of regulation, the water values of some segments may be identical. In these cases the discharge sequence has to be controlled through

$$xd_{m+1,nsi\omega} \le xd_{mnsi\omega}, \quad m \in \{1, \dots, N^{seg} - 1\}, n \in N, s \in S, i \in I, \omega \in \Omega \tag{5}$$

This constraint states that discharge from segment *m+1* cannot start unless discharge from segment *m* has been initiated. To keep reservoirs sustainable, it is assumed that yearly generation cannot exceed yearly inflow:

$$\sum_{h \in H_i} \alpha_h \cdot y_{ghi\omega}^{gen} \le \sum_{s \in S} \vartheta_s \cdot U_{ns\omega}^{Reg,norm} \cdot p_{gi}^{gen}, \quad n \in N, g \in G_n^{HydReg}, i \in I, \omega \in \Omega \tag{6}$$

Run-of-the-river (RoR) hydropower can be modeled in a simpler manner. Inflow is used to bound the hourly generation as a continuous, no-cost power availability. Eq. (7) describes an hourly generation limit based on the average hourly inflow value for all hours in season *s*:

$$y_{ghi\omega}^{gen} \le \frac{U_{ns\omega}^{RoR,norm} \cdot p_{gi}^{gen}}{v_s}, \quad n \in N, g \in G_n^{HydRoR}, h \in H, s \in S, i \in I, \omega \in \Omega \tag{7}$$

The objective function seeks to minimize the net present value of investment costs and expected operational costs over all years $i \in I$. With the hydropower scheduling modeled as above, it can now be formulated as

$$\min_{\mathbf{x},\mathbf{y}} z = \sum_{i \in I} \delta_i \times \left\{ \sum_{g \in G} c_{gi}^{\text{gen}} x_{gi}^{\text{gen}} + \sum_{l \in L} c_{li}^{\text{tran}} x_{li}^{\text{tran}} + \sum_{\omega \in \Omega} p_\omega \left(\begin{array}{l} \sum_{h \in H} \alpha_h \times \sum_{n \in N} \left(\sum_{g \in G_n} \left[q_{gi}^{\text{gen}} y_{ghi\omega}^{\text{gen}} \right] + q_{ni}^{\text{VoLL}} y_{nhi\omega}^{\text{LL}} \right) \\ + \sum_{s \in S} \vartheta_s \times \sum_{n \in N} \sum_{m \in M_n} xd_{mnsi\omega} WV_{mnsi\omega} \end{array} \right) \right\} \tag{8}$$

where the cost of utilizing regulated hydropower is represented by the last term: discharge from segment *m* multiplied by its water value for node *n*, season *s*, year *i* and stochastic scenario *ω*. The other terms include costs for generation and line transmission investments, power generation and lost load. Uncertainty for investment decisions is not considered because all parameters related to this stage are given deterministically in the EMPIRE model.

2.2. Data sets

Water values, maximum reservoir levels and regulated and run-of-the-river inflow has been collected from SINTEF Energy Research in Trondheim, Norway. In order to account for variations throughout the year, seasons have been divided into two categories, summer and winter. Values for initial reservoir levels are assumed higher in summer than winter. For the base scenario, 80 and 60 per cent are assumed to be initial levels for summer and winter seasons, respectively. The other scenarios use ranges from 70 to 90 per cent for summer and 50 to 70 per cent for winter. Initial reservoir levels for Norway and Sweden, the two countries with the largest reservoirs in the system, have been given more accurate data [11]. Minimum reservoir level is assumed to be 5 per cent of a full reservoir.

Due to difficulties related to computation of water values, it is noted that presented results are affected by inconsistent quality of these parameters. The EMPS model, see [10], was used to produce water values; however, the quality of the data set is modest for the years after 2010. As an approximation, we have therefore introduced generation restrictions for regulated hydropower, limiting generation from 2015 to 2060 to a 20 per cent deviation band from the generation in 2010 on a seasonal country-wise level. While large expansions of regulated hydropower in Europe is not expected in the coming decades [12], incorporating such limits is unquestionably a simplification. As such, results do not reflect our final investment recommendations, but can rather be seen as projection guidelines.

Global Change Assessment Model, see [13], provides expected generation shares for various technologies throughout the planning period, given policy scenarios. We utilize these shares in the model, though with two relaxations: Hydro-, wind and solar power are entirely excepted from the GCAM matching constraints, and a deviation allowance of 40 per cent from the GCAM values are embraced for the remaining technologies. Adding these relaxations allows us to identify effects of the new hydropower formulation more clearly, while at the same time preserving some of the added stability by incorporating GCAM matching.

3. Optimization results and analysis

Optimization results are presented for the Global 20-20-20 policy scenario, which is an extension of the EU 20-20-20 scenario to a global scope [14]. The results show optimal values for Europe needed to comply with global targets. All original parameters in EMPIRE unrelated to hydropower are kept intact. It is evident that within the Global 20-20-20 policy regime, the framework favors wind to an extensive degree. As seen in Figure 1 the policy scenario involves large-scale expansions of renewables which take place early in the planning period. Fossil technologies are present in the entirety of the temporal scope, although with significantly lower amounts towards the end of the period, as a result of the increased penetration of renewables.

Differences between the original and the enhanced hydro version of EMPIRE, see Figure 2, show a significant increase in solar capacity for the final model, with a percentage-wise difference peaking in 2040 at 45 per cent. However, from 2050 both models find it optimal to reach maximum capacity of wind and solar power.

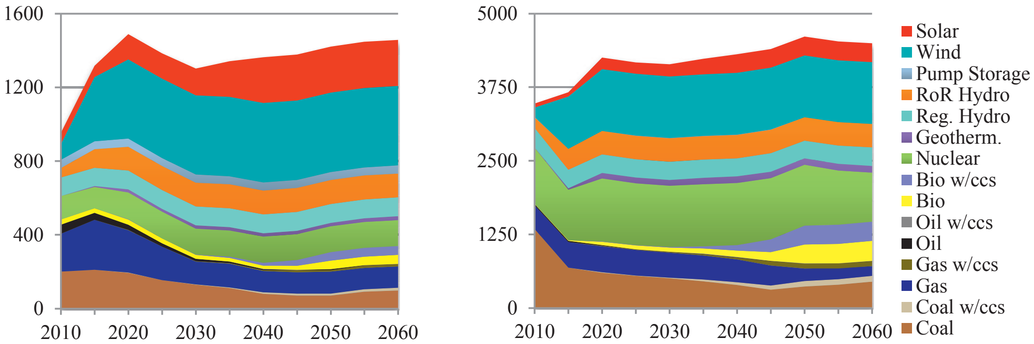

Figure 1: Generation capacity in GW (left) and generation mix in TWh/year (right) aggregated for the European power system.

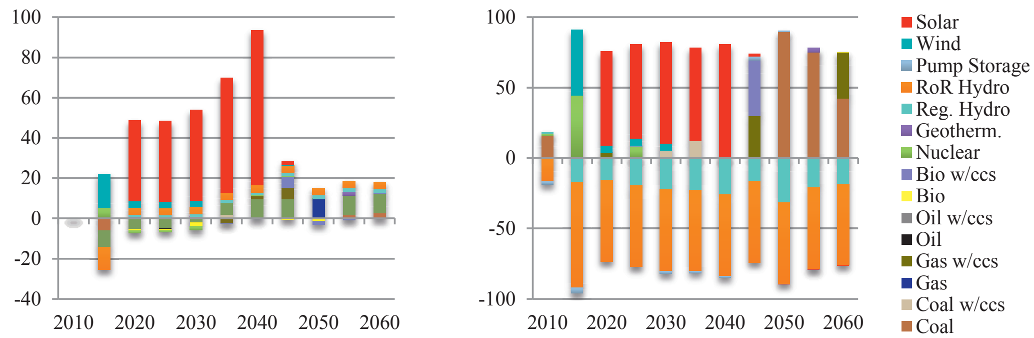

Figure 2: Generation capacity differences in GW (left) and generation mix differences in TWh/year (right) between the final and original models.

The combination of these findings suggests that the use of water values forces EMPIRE to invest in more capacity at an earlier stage, thereby increasing total costs. This can be explained through two effects: Regulated hydropower generation decreases due to more precise cost information through water values, and run-of-the-river hydropower generation is reduced because of a lower amount of available inflow. Consequently, hydropower is found to be overvalued in the original model.

While the combined hydropower generation is reduced, cheaper sources are selected as generation providers to take its place. In the first part of the planning period this is carried out by larger investments in solar power, mainly happening in Germany, Italy and Greece. The increased capacity availability is also reflected in the generation mix, with solar generation at a consistently higher level in the final model for the years 2020 to 2040. Indeed, in 2030 solar generation is 54 per cent higher than in the original model. For the last years, after solar has reached its system-wide maximum installed capacity, a higher utilization of coal serves as substitution supplier.

4. Conclusion

By implementing an enhanced hydropower formulation we have increased the level of detail for this energy source in the EMPIRE expansion planning framework. Results show that the original hydropower availability is too unconstrained, thereby causing an overvaluation of this technology. The revamped cost representation by means of water values leads to a lower utilization of hydropower relative to the original model. An earlier deployment of solar power is carried out to replace the lower generation. Total costs in the system are therefore increased. For both models, extensive investments in intermittent renewables are taking place, amounting to 47 per cent of the total capacity in 2060.

It is noted that the results presented are affected by inconsistent quality of the water values data set. The usefulness of the implementation is nonetheless valuable because of a more comprehensive and accurate representation of hydropower in this investment environment than previously. In further work, an in-depth study of water values parameters would be interesting to conduct.

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