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**Working Paper**

## Supply curves for hydro reservoirs: Estimation and usage in large-scale electricity market models

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House of  
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## SUPPLY CURVES FOR HYDRO RESERVOIRS

### Estimation and Usage in Large-Scale Electricity Market Models

HEMF Working Paper No. 01/2019

*by*

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January 2019

UNIVERSITÄT  
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*Open-Minded*

## Abstract

Hydro electricity generation is of great importance for the current and the future electricity system since it provides electricity without emitting CO<sub>2</sub> and moreover hydro reservoirs offer high operational flexibility. With increasing shares of fluctuating renewable energies, their value is even expected to increase, as – depending on the power plant type – they are able to store electricity. Therefore, an adequate representation of hydro power operation in large-scale electricity models is primordial. The aim of this paper is to analyze empirically the operation of large-scale hydro reservoirs based on observed market data. We derive supply curves for hydro reservoirs in Norway based on electricity price and hydro production time series and analyze key influencing factors. To push further, we apply the resulting supply curves in a multi-region electricity market model and show how they may be used to perform historical and counterfactual simulations.

*Keywords: hydropower, water value, Econometric models, large-scale electricity market models*

*JEL-Classification: C51, L94, Q25, Q41, Q42*

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## Symbols

$A_s$	Parameter for the reference water value of step $s$
$B_s$	Parameter for the impact of the coal price
$C_s$	Parameter for the impact of deviations from the median filling level
$DevMedianFill$	Deviation from the long-term median filling level
$DevMedianFill^\circ$	Deviation from the long-term median filling level minus average deviation from the long-term median filling level
$Efficiency$	Efficiency of a power plant
$Factor_{CO_2}$	CO <sub>2</sub> -factor
$FillLevel_{p,a}$	Calculated filling level of the reservoirs in planning period $p$ and area $a$
$FillLevel_{p,a}^{Ref}$	Reference filling level of the reservoirs in planning period $p$ and area $a$
$Price$	Observed spot price
$Price_{coal}$	Fuel price coal
$Price_{CO_2}$	CO <sub>2</sub> -price
$ResvProd$	Reservoir production
$ResvProd^\circ$	Reservoir production minus average reservoir production
$VarCostsCoal$	Variable costs of a coal-fired power plant
$VarCostsCoal^\circ$	Variable costs of a coal-fired power plant minus average variable costs of a coal-fired power plant
$WV_{p,a}^{unif}$	Water value (former model formulation) in planning period $p$ and area $a$
$WV_{p,a,s}^{new}$	Water value (new model formulation) of steps $s$ in planning period $p$ and area $a$
$WV_a^{Ref}$	Reference water value in area $a$

# 1 Introduction

Hydro electricity generation is of great importance for the current and the future electricity system since it provides electricity without emitting CO<sub>2</sub> and moreover hydro reservoirs offer high operational flexibility. In 2016 nearly 11 % of the European electricity was provided by hydropower plants (cf. International Hydropower Association (2017)). Norway contributed the most, as it is to almost 100 % reliant on hydro power. Hydro power plants with reservoirs are of particular interest due to their ability to store energy and thereby providing flexibility to meet peak and unexpected demand. With increasing shares of fluctuating renewable infeed, their value is even expected to increase. Subsequently we focus on pure hydro storage plants without pumping since those provide the largest storing capabilities, notably in Norway with about 80 TWh energy content.<sup>1</sup>

As hydro reservoirs do not have any fuel costs, the operational decision whether to produce electricity now or later is solely based on opportunity cost considerations. A detailed forward-looking computation of the opportunity cost is very complicated, as it represents a solution to a stochastic programming problem. Yet opportunity cost – also known as water value - may be derived ex post empirically by analyzing the bidding behavior of hydro power plant operators in the electricity market. We therefore perform an econometric analysis and analyze historical electricity prices and production of hydro reservoirs in Norway in order to derive the supply curves of the hydro reservoirs and to identify key influencing factors. To push further, we apply the resulting supply curves in a large-scale electricity market model and show how they may be used to perform historical and counterfactual simulations.

Norway is rather unique with almost 100 % hydro-based electricity production. If we include the additional information that run-of-river power plants cannot regulate their power production and therefore have an opportunity cost of zero, we can argue for the assumption that the price-setting plant is usually a hydro reservoir. If we additionally assume that electricity demand is fairly price-inelastic, we may estimate supply curves in a rather straightforward way. Hence, we regress the hydro reservoir production on the observed electricity spot price along with driving factors that affect the opportunity costs.

In order to derive a reliable model for hydro reservoir supply curves, four different hypotheses are formulated that are based on a simple water value model. Based on these hypotheses, the hydro reservoir supply curves are estimated and later implemented in the large-scale bottom-up

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<sup>1</sup> Also the economics of pumped hydro plants (and consequently their modeling) are somewhat different, since they include the opportunity of reservoir filling through electricity offtake from the system. And Norway so far has not got any pumped hydro plants.

electricity market model JMM (Joint Market Model). With this extension, we are able to significantly reduce the mean absolute error (MAE) of the simulated electricity spot prices without increasing the calculation time of the electricity market model.

The remainder of the paper is organized as follows. The next section gives a brief overview of the relevant literature, with a focus on modeling the operation of hydro reservoirs, especially in Norway. Section 3 develops different hypotheses with regard to the bidding behavior of hydro reservoir operators and section 4 empirically estimates the supply curves of the Norwegian hydro reservoirs. Section 5 describes the implementation of these curves within the large-sale electricity market model and furthermore shows the obtained results and compares them to historical values. The article ends with a summary of the main findings.

## 2 Literature Review

Different approaches to model the operation of hydro reservoirs and the corresponding opportunity costs, aka water values, in large-scale electricity models are summarized in the following. The literature on modeling the operation and/or the bidding behavior of hydro reservoirs is extensive but it may be divided at least roughly in the following four groups: stochastic and deterministic optimization approaches as well as simple parametric functions and econometric approaches. The literature can be furthermore differentiated according to the prime modelling objective. On the one hand there are articles that focus on solving scheduling problems (e.g. Pereira and Pinto (1991), Helseth et al. (2013), Gjelsvik, Mo, and Haugstad (2010)) and on the other hand articles that look for an adequate representation of hydro reservoirs in an electricity market modelling approach to answer research questions that do not focus on hydro modelling (e.g. Hirth (2016); Spiecker, Vogel, and Weber (2013); Trepper, Bucksteeg, and Weber (2015a)).

The stochastic approaches include notably stochastic dynamic programming (SDP) and stochastic dual dynamic programming (SDDP). They provide solutions for multistage stochastic optimization problems (cf. Pereira and Pinto (1991)) and especially SDDP is widely used to solve hydrothermal scheduling problems. These approaches are advantageous in view of detailed modeling of system characteristics while taking into account uncertainties like future water inflow. Their main disadvantage is the considerable computation time requirement. An application of the SDP method to solve the large-scale optimization problem within the electricity market model (EMPS)<sup>2</sup> is e.g. described in Wolfgang et al. (2009). They use the EMPS model for investigating possible reasons for reduced hydro reservoir levels in Norway after deregulation in

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<sup>2</sup> EFI's Multi-area Power-market Simulator.

1991. In view of computation time, SDDP is advantageous in comparison to SDP since it circumvents the problem of “curse of dimensionality”<sup>3</sup> by approximating the expected future cost function by Benders cuts so that no state discretization is necessary.<sup>4</sup> SDDP was developed for the Brazilian system by Pereira and Pinto (1991) and has been applied for many more systems like the Norwegian hydro system. Gjelsvik, Mo, and Haugstad (2010) apply SDDP on two different scheduling problems of hydrothermal power systems. One model for a small system without internal transmission bottlenecks, where SDDP is combined with SDP and one model for a large system. Helseth et al. (2013) present a SDDP-based scheduling model for the Icelandic power system. Their model adds linearized power flow constraints, start-up costs and wind stochasticity. They find that the incorporation of further details in the scheduling leads to more realistic results. Gjerden et al. (2015) test the SDDP method on a detailed model of Norway, where each hydro reservoir is modeled individually, resulting in five hundred hydropower modules. They compare the results of the SDDP model with a model that is based on aggregation and disaggregation. However, they conclude that the SDDP method is disadvantageous when simulating the system using historical inflow series and is furthermore more computation time consuming.

Zambelli et al. (2006) compare the performance of deterministic models and stochastic models for long-term hydrothermal scheduling problems. They consider as deterministic approaches deterministic dynamic programming and a storage guide curve method and as stochastic approaches stochastic dynamic programming models with and without autocorrelation in inflow time series. In a simulation study for three different basins in Brazil they conclude that the dispatch using a deterministic model is more cost efficient than with the stochastic model.

Parametric approaches include besides storage guide curves (cf. Zambelli et al. (2006)) deterministic models that iteratively determine water values as a function of e.g. reservoir levels. This is for example applied by Zakeri et al. (2016), who evaluate the impact of Germany’s energy transition on the Nordic electricity market. They model the water values as a function of weekly hydro inflow, residual load 24 hours ahead and the amount of water in the hydro reservoirs and they adjust them iteratively to match observed production patterns.

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<sup>3</sup> „Curse of dimensionality“ describes the problem that the calculation time increases with increasing number of states – which in turn increase exponentially with the number of state variable (reservoirs) considered in SDP (cf. Pereira and Pinto (1991)).

<sup>4</sup> Besides of SDDP, another method to overcome the problem of “curse of dimensionality” is to aggregate hydro reservoirs to reduce the problem into a single hydro reservoir system (cf. e.g. Arvanitidis and Rosing (1970)).



The econometric approaches try to assess hydropower production or water value profiles. E.g. Birkedal and Bolkesjø (2016) explain the hydro reservoir production by using a two stage least squares model. The authors report that the marginal costs of coal power plants, the inflow and hydro balance are important factors. However, they do not use the estimated hydropower production profiles further within a fundamental modelling context.

This paper extends the existing literature by developing econometric approaches and combining them with fundamental models. We estimate empirically validated supply curves of hydro reservoirs. These are then implemented in the large-scale electricity market model JMM (Joint Market Model). Therefore, our method has the advantage that the calculation time of the fundamental model does not increase exorbitantly with an improved modeling of hydro reservoirs. Furthermore, a detailed description of the hydropower system characteristics is not needed, as their bidding is described based on the outcomes of the econometric model. As detailed hydropower system data might be only available for power plant operators or against payment, our method still yields good results without considering detailed datasets on reservoir characteristics. Compared to simple deterministic optimization approaches, the newly developed approach also provides more realistic operation patterns.

### **3 Formulation of Hypotheses on Hydro Reservoir Supply Curves**

In order to derive an empirically validated model that is also theoretically sound, initial hypotheses are formulated for hydro reservoir supply curves that are based on a simple water value model. Therefore we state four hypotheses: the first two hypotheses are about the relation between the water value of hydro reservoirs and marginal costs of thermal power plants and the last two hypotheses describe the relation between the water value and deviations from equilibrium filling levels.

The standard supply-stack or merit order model assumes that power plant operators bid their marginal costs in the electricity spot market. Therefore, in systems that consist solely of thermal power plants, the electricity spot price is determined by the price-setting marginal power plant. The variable costs of hydro reservoirs are almost non-existent. Even in case of Norway, where electricity production is dominated by hydropower plants, the electricity price rarely experiences large drops to values near or even below zero (cf. Nord Pool Spot AS (2018)). This can be explained by considering the flexibility of hydro reservoirs. The operators face the decision whether to use the water in the hydro reservoirs now or later. Therefore, the relevant costs are the opportunity costs (water value) of using the water in the future (cf. Sandsmark and Tennbakk (2010)). The water value is hence influenced by hours with thermal price-setting technologies with higher variable costs. This can happen directly or indirectly, if a price-setting hydro reservoir

provides a relevant opportunity for other reservoirs. Even if the thermal power plants are price-setting in only a few hours, their marginal costs might affect the power price in many hours over the year. Therefore, the following hypothesis is formulated:

**H1: The water value of hydro reservoirs rises with an increase of the marginal costs of substituting thermal power plants**

Overall, the water value of hydro reservoirs is highly affected by the flexibility of the reservoirs. One important indicator for the flexibility and therefore the water value is the load (or capacity) factor (cf. Sandsmark and Tennbakk (2010)), which is defined as the ratio between the turbine capacity and the yearly production. If we neglect the uncertainty that an operator of a hydro reservoir is exposed to and neglect other restrictions for the hydro reservoir dispatch as well as the influence of the hydro reservoir on the electricity price, the main rationale for the water value of a single hydro plant may be described as follows. The opportunity costs are mainly determined by the possibility to save the water and use it in the hours with the highest electricity prices. If the reservoir is sufficiently large compared to the inflows, the pattern of inflow over the year is not important, only the overall energy input. Figure 1 shows for such a case an exemplary price-duration curve (upper part of the figure) and the corresponding electricity production of a hydro reservoir (lower part of the figure) for one year. In order to maximize the profits, the hydro reservoir operator chooses to produce electricity in hours with the highest prices. The water value is then the marginal value of the last unit of electricity sold. If the electricity prices are above the water value, the turbine of the hydro reservoir is run on full capacity, which is shown in the lower part of the figure. The water value is then chosen such that the total annual electricity production (i.e. the hatched area in the lower part of Figure 1) corresponds to the energy provided through the yearly inflows.

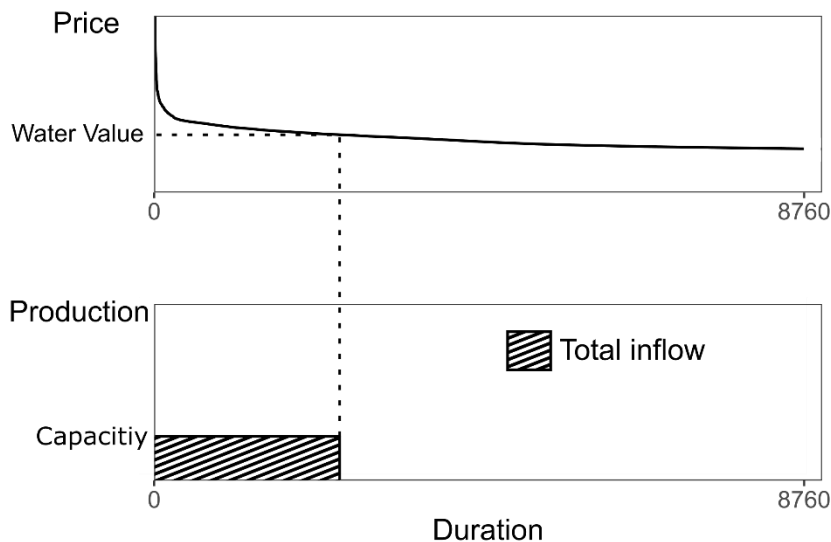


Figure 1: Price duration curve, water value and production schedule of a stylized hydro reservoir.

In the price duration curve in Figure 1, two parts may be distinguished: A small part with very high prices and a large part with moderate prices. The water value is typically located in the latter segment, given that typical load factors of hydro reservoirs range between 0.23 and 0.70<sup>5</sup> (EC SETIS (2013)). These are load factors of typical mid-merit plants in thermally dominated systems. Hence we expect mid-merit plants like coal-fired power plants to be the relevant price-setting technology for hydro reservoirs (cf. also Podewski and Weber (2018)). Even though Norway has no coal-fired power plants, Norway has a large interconnector capacity to Denmark, that may provide the relevant opportunity through cross border electricity trade (cf. Entso-e (2018), Green and Vasilakos (2012)). The smaller the reservoir in relation to the turbine capacity, i.e. the smaller the load factor, the more the marginal water value increases. These hydro power plants are then located more to the right on the supply curve. They then reach operating hours where typically prices are not set by mid-merit plants but rather by peaking plants. Hence we postulate as second hypothesis:

**H2: The water values of hydro reservoirs on the left side of the relevant supply curve are more prone to changes in the marginal costs of mid-merit power plants than for those at the upper right end.**

Other constraints that highly affect the reservoir operation are the risks of spillage or running dry. Both reduce the number of hours with profitable operation opportunities. As the inflow to the hydro reservoirs follows a seasonal pattern with superposed stochastic fluctuations (cf. Sandsmark and Tennbakk (2010)), inflows may be described as a time-variable but stationary stochastic process. Then there should also be a time-varying equilibrium filling level which corresponds to

<sup>5</sup> Sandsmark and Tennbakk (2010) give a wider range between 0.06 and 0.86 for Statkraft hydropower stations in Norway, yet indicating that for the bulk of capacity, load factors range between 0.3 and 0.7.

the optimal filling level in absence of past disturbances and in view of future stochastic fluctuations. This time-varying equilibrium filling level is reflective of average inflow and demand patterns. E.g. at the end of the winter the equilibrium filling level is rather low in cold regions with snowfall and low inflows during winter whereas it is rather high after the snowmelt. Yet if there is less water available at the beginning of the winter than usual, this is a sign of scarcity. Conversely unexpected additional inflows during February or March would induce more than average hydro availability. Therefore the deviation from the equilibrium filling level is a clear indicator of scarcity or abundance and should influence the water value. The inflow into the reservoirs is a main driver of the filling level, yet by itself it is not an indicator of scarcity in the presence of large reservoirs. It rather affects the supply curve indirectly through its cumulative effect over time. Therefore, we hypothesise the following:

**H3: Deviations of the filling level from the season-dependent equilibrium filling level impact the water value in opposite direction.**

The deviation from the equilibrium filling level affects the bidding behaviour of the hydro reservoirs. Hence, if the filling level is above the equilibrium filling level, the bidding prices should tend to decrease. If we additionally consider that the price duration curve, as indicated in Figure 1, is generally much steeper for higher prices, we can conclude that the deviation from the equilibrium filling level might have a stronger effect on the right side of the relevant supply curve. This leads to the last hypothesis:

**H4: Deviations of the filling level from the season-dependent median filling level have a larger impact on the water value of hydro reservoirs on the right side of the supply curve.**

## 4 Empirical Estimation of Hydro Reservoir Supply Curves

In the following, a linear model is stated in order to assess our previously formulated hypotheses empirically and to derive an empirically validated specification of supply curves for hydro reservoirs. Problems with the model building, like operationalization, endogeneity, non-linearities and estimation errors due to the initial assumptions are discussed.

### 4.1 Operationalization

In the previously stated hypotheses, the water value, the variable costs of mid-merit power plants and the deviation from the equilibrium filling level are identified as main drivers for the shape of the supply curves of hydro reservoirs. As these variables are not directly observable, they need to be operationalized for empirical analyses. Table 1 summarizes the operationalization of these three variables.

Table 1: Overview operationalization.

Variables	Operationalization	Abbreviation
Water Value	Observed Spot Price	Price
Reservoir production	Observed production in GWh/h	ResvProd
Deviation from equilibrium filling level	Deviation from long-term median filling level conditional on the week of the year (1-53)	DevMedianFill
Marginal costs mid-merit power plants	Variable Costs Coal (Approximated with CO <sub>2</sub> Cal 2018 and the Coal Price Index)	VarCostsCoal

The water value of the hydro reservoirs is not observable. However, an indirect observation of the supply curve of the hydro reservoirs might be possible. If a hydro reservoir is the price-setting power plant, the bid is equal to the observed spot price and the water value is revealed. Hours in which other power plants are price-setting might bias this estimate. In Figure 2 the latter problem is visualized based on a standard merit order curve with fixed demand. If a gas-fired power plant is price-setting, the observed price will overestimate the corresponding water value, as the bid of the hydro reservoir is lower. Still, the assumption that every observed price uncovers a bid of a hydro reservoir is still reasonable in a power system that is dominated by hydro reservoirs as Norway.

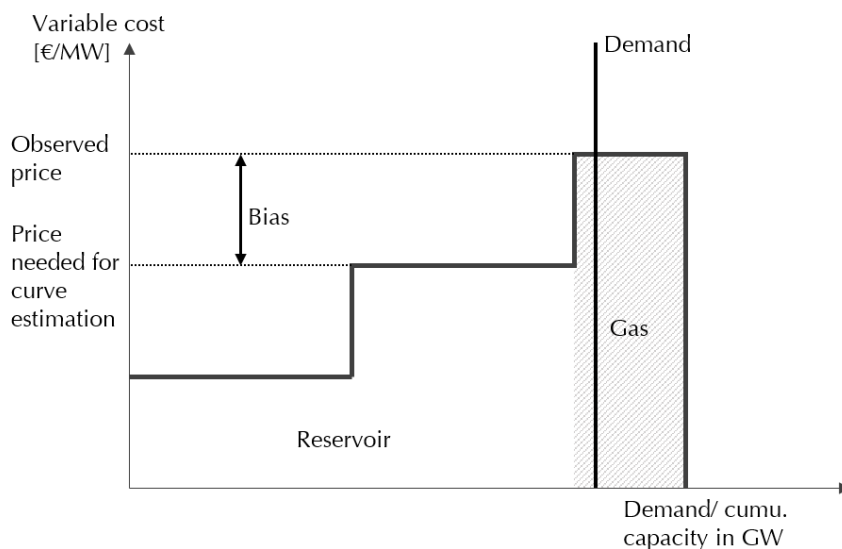


Figure 2: Possible bias due to price-setting thermal power plants.

Since run-of-river hydro plants have the lowest opportunity costs of all hydro plants, namely zero, whereas prices are almost always above zero, it is very likely that a hydro plant is the current price-setting plant or at least close to it.

The data on the production of hydro power plants is available and can be used without further modification. For the observation period, coal-fired plants have been the dominating mid-merit power plants in the Nordic and Continental power system (e.g. (Energinet; Danish Energy Agency;

2018)). The marginal costs of mid-merit power plants can therefore be approximated from the coal and CO<sub>2</sub> allowance prices based on typical plant characteristics using equation (1).

$$VarCosts_{Coal} = \frac{(Price_{coal} + Factor_{CO_2} * Price_{CO_2})}{Efficiency} \quad (1)$$

with:  $Factor_{CO_2} = 0,34 \text{ tCO}_2/\text{MW}_{th}$ ,  $Efficiency = 0.4 \text{ MWh}_{el}/\text{MWh}_{th}$

The operationalization of the deviation from the equilibrium filling level is more difficult, as it would be very complex to calculate the equilibrium filling level. Still, Zambelli et al. (2006) show that for long-term hydro scheduling the time of the year seems to be the most important factor for the equilibrium filling level. Therefore, we assume that the latter is a fixed seasonal cycle within the year and use the long-term median filling level conditional on the week of the year as an approximation.

In Table 2 the sources for the used data are summarized. For the empirical estimation we use the period from 01/2016 – 06/2018 as for this period all necessary data are available.<sup>6</sup> Missing values were interpolated in the pre-processing. In Table 3 key descriptive statistics of the data are summarized.

Table 2: Description and source of data.

Data	Unit	Time Frame	Source
Norway spot prices (NO1-NO5)	€/MWh	01/2016-06/2018 (Hourly)	Nord Pool Spot AS (2018)
Reservoir production	MWh	01/2016-06/2018 (Hourly)	Entso-e 2018
Filling level	%	01/2002-06/2018 (Weekly)	NVE (2018)
EU CO <sub>2</sub> allowance (Cal 2018)	€/t CO <sub>2</sub>	01/2016-06/2018 (Daily)	energate (2018)
Coal Price Index	€/t	01/2016-06/2018 (Daily)	energate (2018)

<sup>6</sup> Data covering the period from 01/2002-06/2018 is used for the calculation of the equilibrium filling level.

Table 3: Descriptive statistics (Whole Norway 01/2016-06/2018).

Data	Mean	Median	Standard Deviation	Min	Max
Norway spot prices [€/MWh]	29.45	28.19	8.24	4.74	169.83
Reservoir production [GW]	14.99	14.33	4.16	5.05	24.93
Filling level [percent]	60.72	63.2	18.35	25.1	86.6
EU CO <sub>2</sub> allowance (Cal 2018) [€]	6.95	5.77	2.98	3.99	16.29
Coal Price Index [€/t]	67.59	70.78	12.27	45.2	91.81
Variable cost coal-fired power plant	26.66	27.41	5.06	17.99	38.91
Deviation from median filling level	0.47	0.40	4.66	-9.2	11.4

## 4.2 Endogeneity and Non-Linearity

Endogeneity might be a problem for two variables of our analyses due to simultaneous causalities. The relationship between the production of the hydro reservoir and the observed spot price as well as the relationship between the deviation from the equilibrium filling level and the observed spot price might add a bias to the regression model.

The estimation of demand and supply curves is a classical example of regression models with potential endogeneity problems. These may be circumvented through the use of instrumental variable estimators. E.g. Birkedal and Bolkesjø (2016) use the power price of Germany as an instrument for the endogenous variable of the power price as they regress the production of hydro reservoirs on the observed power price. Yet Norway has no pumped storage capacity by now and a large-scale demand side management is not existent. Therefore, the apparent elasticity of demand in electricity spot market supply curves is mainly due to power plants that have sold their position on the future market and are willing to buy back their position within the spot market at a certain price level. In a fundamental modelling approach as chosen here, trading on the future market is disregarded and consequently the demand elasticity should rather reflect the price elasticity of physical demand while making causal inference on the supply curve for physical supply. As the price elasticity of physical demand is (close to) zero, observations of different price-quantity pairs for market results allow to infer the supply curve in an unbiased way.

For the filling level, a bi-directional causality yet may be expected a priori: A higher filling level reduces the water value and thus shifts the supply curve downwards (cf. H3). Yet with lower bidding prices, the production of hydro reservoirs tends to increase which in turn reduces the

filling level for the week. Yet this not a problem when using the available data: the reservoir filling is reported for the beginning of the week. Therefore, the inferred water values and corresponding supply curves will not feed back onto the observed filling level but only affect the filling level of the next week.<sup>7</sup>

A problem for the model building are possible non-linearities in the supply curve estimation. In Figure 3 price-quantity pairs for an exemplary week are plotted. Since water values for large reservoirs just like their filling levels and coal prices change rather slowly over time, these price-quantity curves should reflect the supply curve, given the assumption of price-inelastic yet time-varying demand.

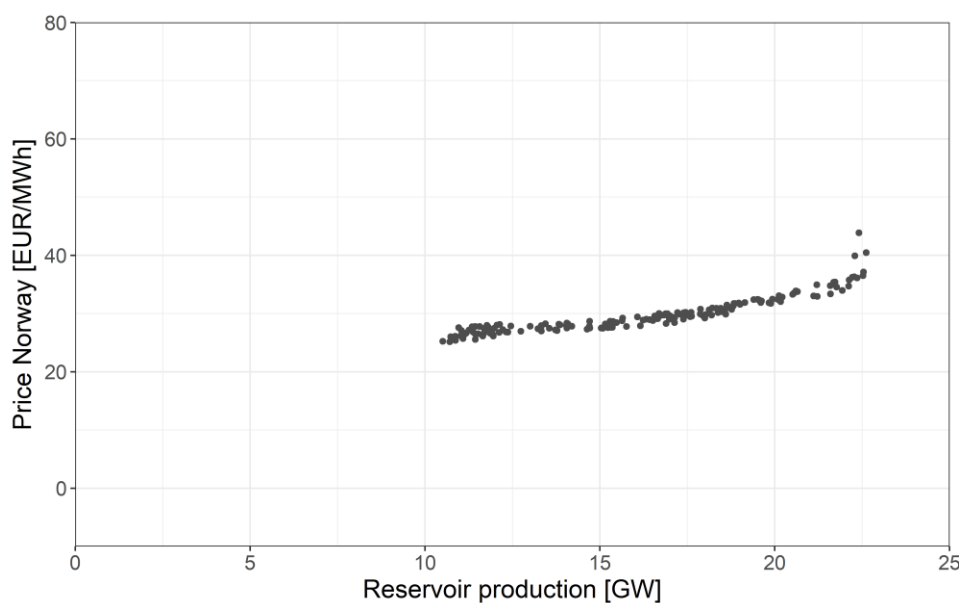


Figure 3: Scatterplot of prices in Norway vs. reservoir supply in Norway in week 49 in 2017.

In this example as in other weeks (notably with high demand), a linear relationship is observed in the middle of the supply curve whereas the slope of the supply curve increases sharply on the right side. In these hours, either hydro power plants with significantly different water values or thermal power plants could be price-setting. In the first case, it might be reasonable to allow the model to adjust to this non-linear shape. In the second case, the data points might bias our estimation and should be removed. As we cannot evaluate the price-setting technology, both cases are considered in the following.

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<sup>7</sup> An unclear causal relationship is by the way the reason why we refrain from including current hydro inflow as an additional explanatory variable (as done e.g. by Zakeri et al. (2016)). The impact of the inflow of the preceding weeks is anyhow included in the filling level of the current week. Current inflow should therefore impact bidding behavior of hydro producers mostly in as far as it may change expectations for future scarcity.



### 4.3 Regression Models and Results

For the estimation of the hydropower supply curves, the hypotheses need to be reformulated. Figure 4 illustrates graphically how the hypotheses can be stated under the assumption of a linear supply curve.

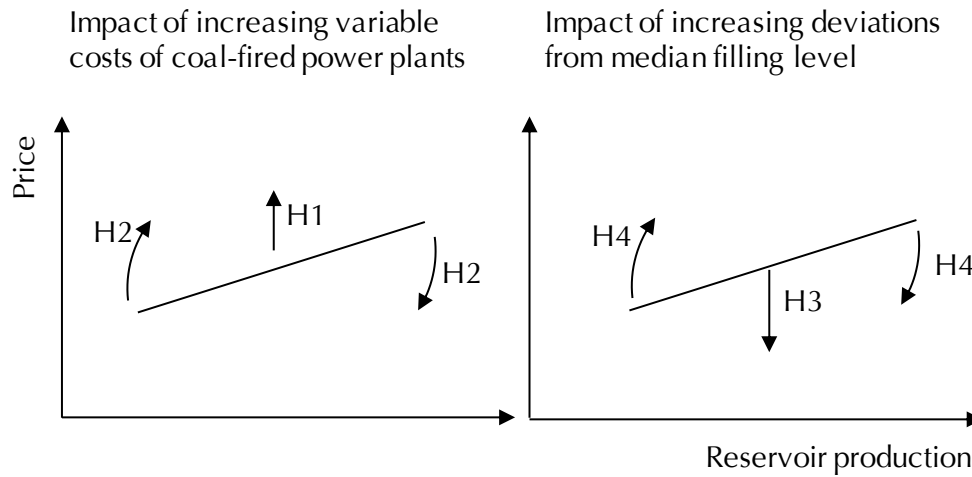


Figure 4: Visualization of the effects of the different hypotheses.

The observed power price is on the y-axis and the hydro reservoir production on the x-axis. The general effects on the water value stated in hypothesis H1 and H3 can be expressed as a vertical shift of the supply curve. The differing effects within different parts of the merit order, as stated in hypothesis H2 and H4, correspond to a change in the slope of the linearized supply curve and can be modeled econometrically as a simple interaction effect. Hypothesis H1 and H2 state that an increase of the marginal costs of coal-fired power plants will result in an increase of the water value, while having a larger effect on the left side of the relevant merit order curve. This can be translated to a rise and clockwise rotation. Hypotheses H3 and H4 can be transformed analogously to a decrease and a clockwise rotation of the supply curve with an increase of the deviation from the equilibrium filling level. The following equations show the regression model with interaction terms. The variables are reduced by their mean values which is indicated through the symbol  $^{\circ}$ . The mean values can be found in Table 3. This procedure ensures that the non-interaction coefficients are easier to interpret since they correspond to the mean shifting effect on the supply curve – or equivalently the shifting effect at the mean of the observed reservoir production values.

$$\begin{aligned}
 \text{Price} = & \beta_0 + \beta_1 \cdot \text{ResvProd}^{\circ} + \beta_2 \cdot \text{VarCostsCoal}^{\circ} + \beta_3 \cdot \text{DevMedianFill}^{\circ} \\
 & + \beta_4 \cdot \text{ResvProd}^{\circ} \cdot \text{VarCostsCoal}^{\circ} \\
 & + \beta_5 \cdot \text{ResvProd}^{\circ} \cdot \text{DevMedianFill}^{\circ} + \epsilon
 \end{aligned} \tag{2}$$

This can be rewritten as:

$$\text{Price} = \alpha_0 + \alpha_1 \cdot \text{ResvProd}^\circ + \epsilon \quad (3)$$

with

$$\alpha_0 = \beta_0 + \beta_2 \cdot \text{VarCostsCoal}^\circ + \beta_3 \cdot \text{DevMedianFill}^\circ$$

$$\alpha_1 = \beta_1 + \beta_4 \cdot \text{VarCostsCoal}^\circ + \beta_5 \cdot \text{DevMedianFill}^\circ$$

Therefore, we can interpret the factors  $\beta_4$  and  $\beta_5$  as changes to the slope parameter  $\alpha_1$ . For example, a positive value of  $\beta_4$  indicates a increase of the slope parameter  $\alpha_1$  with an increase of the variable costs of coal-fired power plants. This can be graphically interpreted as a clockwise turn of the supply curve with  $\alpha_0$  as the centre of rotation.

In an additional specification, we include nonlinearities in the supply curve by introducing the variable  $\text{ResvProd}^\circ$  (*Kink*). This variable is zero if the value of  $\text{ResvProd}$  is smaller than 23 GW and  $\text{ResvProd}^\circ - 23$  otherwise. Hence, the model includes a kink of the supply curve. This extended model is given in equation (4).

$$\begin{aligned} \text{Price} = & \beta_0 + \beta_1 \cdot \text{ResvProd}^\circ + \beta_2 \cdot \text{VarCostsCoal}^\circ + \beta_3 \cdot \text{DevMedianFill}^\circ \\ & + \beta_4 \cdot \text{ResvProd}^\circ \cdot \text{VarCostsCoal}^\circ \\ & + \beta_5 \cdot \text{ResvProd}^\circ \cdot \text{DevMedianFill}^\circ + \beta_6 \cdot \text{ResvProd}^\circ (\text{Kink}) + \epsilon \end{aligned} \quad (4)$$

In total we test four specifications. Table 4 shows the overall results of the regression analysis. Furthermore, the regression coefficients and significance levels are shown. The four models are chosen to test the proposed hypotheses and to take into account the previously stated concerns about a possible non-linearity of the supply curve. The model (0) does not include any interaction terms. Within model (1), non-linearities is neglected (see equation (2)), yet interaction effects are considered. In model (2) potential outliers are removed. They are identified by estimation of the reservoir supply curve on a weekly basis and by using Cook's distance. This model should be preferred under the assumption that thermal price setting power plants bias our estimation on the right hand side of the supply curve. In model (3) an additional variable is included that allows a kink in the supply curve at a reservoir production level of 23 GW (see equation (4)). This model is preferable under the assumption of price setting hydro reservoirs on the right side of the merit order.

Table 4: Regression results of the different model variants.

	<i>Dependent variable:</i>			
	Price			
	(0)	(1)	(2)	(3)
ResvProd <sup>°</sup>	0.69***	0.71***	0.53***	0.58***
VarCostsCoal <sup>°</sup>	0.81***	0.75***	0.76***	0.76***
DevMedianFill <sup>°</sup>	-0.41***	-0.46***	-0.46***	-0.49***
ResvProd <sup>°</sup> ·VarCostsCoal <sup>°</sup>		-0.04***	-0.04***	-0.03***
ResvProd <sup>°</sup> · DevMedianFill <sup>°</sup>		-0.01*	-0.02***	-0.04***
ResvProd <sup>°</sup> (Kink)				35.46***
Constant	0.00	-0.003	-0.30	-0.27
Observations	21,888	21,888	19,003	21,888
R <sup>2</sup>	0.53	0.54	0.64	0.61
Adjusted R <sup>2</sup>	0.53	0.54	0.64	0.61
Durbin-Watson statistics	0.16***	0.16***	0.10***	0.20***

*Note:* \*p<0.1; \*\*p<0.05; \*\*\*p<0.01, °mean subtracted

A value of zero for all interaction effects has still a reasonable explanation. The Durbin-Watson statistics suggest that there is significant autocorrelation in the data. Therefore, Newey-West standard errors are computed. The R<sup>2</sup> is reasonably high and furthermore it shows that the model improves a lot with the consideration of non-linearities.

In order to validate our hypotheses we need to show that the regression results are in line with the relations shown in Figure 4. The first coefficient, corresponding to the variable *ResvProd*, describes the average slope of our supply curve (or more precisely the estimated slope of the hydropower supply curve when all explanatory variables take their average value). It is positive in all four models. A positive coefficient for the other single effect variables (*VarCostCoal*, *DevMedianFill*) describes an upward shift of the supply curve with an increase of the variable. A negative value of an interaction effect implies a clockwise rotation of the supply curve when the variable has an above-average value and vice versa. The positive coefficient of *VarCostCoal* and the negative value of the corresponding interaction effect hence confirm hypotheses H1 and H2. The negative coefficient of *DevMedianFill* and the negative coefficient of the corresponding interaction effect are in line with hypotheses H3 and H4. Still, the latter coefficient is insignificant in model (1). Therefore, hypothesis H4 can only be confirmed based on model (2) or (3). The additional coefficient of the variable “ResvProd<sup>°</sup> (Kink)” in model (3) can be interpreted in the following way. If the reservoir production is lower than 23 GW, the slope of the supply curve at a mean value of the “Variable costs of coal-fired power plants” and “Deviation from the median

filling level" is 0.58 €/MWh/GW. At a production level above 23 GW the slope is the latter plus 35.46 €/MWh/GW.

In order to test the obtained hydropower supply curves within a large-scale electricity market model, we implement these in the scheduling model WILMAR Joint Market Model (JMM) and compare the results with both - the results of a simple single reservoir storage guide curve (similar to Zambelli et al. (2006)) and historical prices of the year 2013.

## 5 Application in a Large-Scale Electricity Market Model

Subsequently, the large-scale electricity market model JMM and especially the modelling of hydro reservoirs within the model is presented (section 5.1). Section 5.1.1 presents the standard modelling of hydro reservoirs within the JMM (version JMM – WV<sup>unif</sup>) and section 5.1.2 describes the implementation of the empirically derived hydropower supply curves within the JMM (version JMM – WV<sup>step</sup>). Then the resulting electricity prices obtained in a historical simulation are compared to observed prices and to the prices of the earlier standard model variant based on a single reservoir storage guide curve (section 5.2).

### 5.1 Large-Scale Electricity Market Model

The JMM was originally developed in the EU-funded project Wind Power Integration in Liberalized Electricity Markets (WILMAR) (cf. Barth et al. (2006)). The used version of the JMM is a detailed linear programming model that covers the geographical region of Europe with its corresponding markets and market design (cf. Tuohy et al. (2009); Meibom et al. (2011); Trepper, Bucksteeg, and Weber (2015); Bucksteeg, Niesen, and Weber (2016)). The JMM is based on the assumption of system cost minimization covering fuel, CO<sub>2</sub>, start-up and further variable costs. The JMM models each hour of the considered year and encompasses a rolling planning approach where two planning periods are distinguished: a day-ahead loop and an intraday loop. The day-ahead loop starts, in line with EPEX-based trading, at 12 o'clock one day ahead and fixes the operation planning for the following day according to available information at that time. In a second loop – 12 hours later – new information can be included and the planning is updated. In order to reflect reality, the model includes restrictions for the electricity market. These relate, among others, to the reserve power market, the electricity exchange between countries or regions as well as to the modelling of district heating and CHP units (cf. Felten, Baginski, and Weber (2017)). Moreover, several technical restrictions like startup time, minimum up and down times are considered as described more detailed in Tuohy et al. (2009).

### 5.1.1 Standard Modeling of Hydro Reservoirs within the JMM

So far, the operation of hydro reservoirs has been rather simplified, as the short planning horizon does not allow for a detailed scheduling of hydropower plants with large reservoirs. Rather the scheduling is done based on a regularly updated yet uniform water value. Only one aggregated reservoir in each area is considered, so that the same water value applies to all reservoirs in that area. Besides of standard restrictions like the hydropower reservoir dynamic equation and maximum/minimum reservoir capacity, the operation of the hydro reservoirs is driven by the water values which are updated so that the filling level tracks a storage guide level. The water values are hereby calculated using the following formula:

$$WV_{p,a}^{unif} = \max(1, WV_a^{Ref} + \alpha \cdot (FillLevel_{p-1,a}^{Ref} - FillLevel_{p-1,a})) \quad (5)$$

The water values  $WV_{a,p}^{unif}$  for area  $a$  and planning period  $p$  are thereby determined by the comparison of the reference filling level  $FillLevel_{p-1,a}^{Ref}$  with the calculated filling level  $FillLevel_{p-1,a}$  for the end of the previous period. If the calculated filling level deviates from the reference filling level, the water value  $WV_{p,a}^{unif}$  is adjusted to depart from the reference value  $WV_a^{Ref}$ <sup>8</sup>. For example, the water value increases if the filling level goes below what is normal for the time of the year. Hence, the production of the reservoirs decreases so that the filling level approaches again the reference level. The adjustment parameter  $\alpha$  is thereby set to one in the standard specification while the maximum operator is only used to prevent negative water values.

### 5.1.2 Implementing Empirically Derived Hydropower Supply Curves within the JMM

In this section, necessary adjustments of the empirically derived supply curves are described first and subsequently the adjustments within the JMM are shown.

#### *Adjustments within the empirically derived supply curves*

In order to keep the linear formulation of the JMM, the empirically derived supply curves need to be discretized. The (piece-wise) linear supply curve is approximated with a merit order with 15 pseudo-technologies, representing a stepwise supply function. This procedure is illustrated in Figure 5.

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<sup>8</sup> For backtesting model runs, the chosen reference water value is the average base price seen in that year. In simulation runs for future years, an initial model run is used in order to determine the future average electricity price.

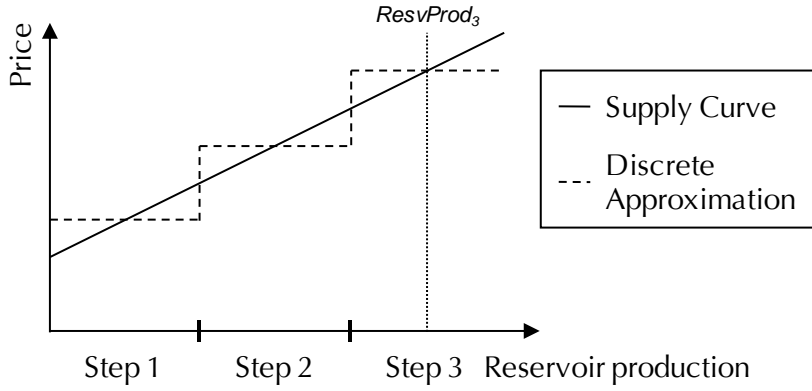


Figure 5: Step function approximation for the reservoir supply function.

Taking the model specified in equation (2) as starting point, we compute for each step  $s$  the water value function as in equation (6). Thereby the value of the reservoir production in the middle of the step is used for the evaluation.

$$WV_s = A_s + \text{VarCostCoal}^\circ_s \cdot B_s + \text{DevMedianFill}^\circ \cdot C_s \quad (6)$$

with

$$A_s = \beta_0 + \beta_1 \cdot \text{ResvProd}^\circ_s$$

$$B_s = \beta_2 + \beta_4 \cdot \text{ResvProd}^\circ_s$$

$$C_s = \beta_3 + \beta_5 \cdot \text{ResvProd}^\circ_s$$

$$s \in 1 \dots N_s$$

The constant  $A_s$  describes the reference water value of the step  $s$  of the supply curve,  $B_s$  describes the impact of the coal price and is hence multiplied with the average variable cost of the coal-fired power plants relevant for area  $a$ , whereas the coefficient  $C_s$  measures the impact of the deviations from the median filling level. This formulation is then used further within the fundamental model JMM.

### ***Adjustments within the JMM: version JMM – $WV^{\text{step}}$***

In order to implement the estimated and adjusted supply curves for hydro reservoirs of section 4 in the large-scale electricity market model JMM, the model is adapted. The new approach reflects that, in reality, there are many different hydro reservoirs in one area with different expected inflow and storage capacity and consequently different water values. The estimated linear or piece-wise linear supply curve (cf. section 4.3) is then approximated by a series of turbines with different but increasing water values.<sup>9</sup> If e.g.  $N_s = 15$  different steps in the supply curve of area  $a$  are defined

<sup>9</sup> The approximation consists in not modelling the number of reservoirs that exists in reality but to approximate their supply function by a predefined number of steps of the aggregate supply curve. We also do not model separate reservoirs but one reservoir with multiple turbines, described through the discrete steps of the supply curves.

(cf. equation (6), these are modeled as 15 different turbines for one reservoir for that area. During the rolling planning process, water values are then calculated by the following formula:

$$WV_{p,a,s}^{step} = \max(1, A_s + VarCostCoal_{p,a} \cdot B_s + (FillLevel_{p-1,a} - FillLevel_{p-1,a}^{Ref}) \cdot C_s) \quad (7)$$

The water values for area  $a$  at planning loop  $p$  are computed for each step  $s$  of the estimated bidding curve based on the parameters obtained in section 4 and making use of the relevant variable cost and of the difference between the calculated filling level  $FillLevel_{p-1,a}$  and the median filling level  $FillLevel_{p-1,a}^{Ref}$ .

These water values, multiplied with the production of the hydro reservoirs, enter the objective function so that the cheapest turbines in the supply curve are called first to produce electricity.

In the following application we use this approach only for Norway, where the empirical coefficients have been estimated. The water values for areas without supply curve estimation are still approximated using the model variant JMM –  $WV^{unif}$  described before.

## 5.2 Results

Model runs are performed using data for the year 2013. As indicated above, the results obtained with the new supply curves in the model variant  $JMM - WV^{step}$  are compared to the former model variant  $JMM - WV^{unif}$  and to historical values for the year 2013.<sup>10</sup> The focus of the analysis lies on Norway for which supply curves have been estimated empirically.<sup>11</sup> The key indicators used to evaluate the performance of the estimated supply curves within the JMM are the mean absolute error (MAE) (see equation (8)) and the root mean squared error (RMSE) (see equation (9)) for the modeled electricity prices:

$$MAE = \frac{1}{T} \sum_{t=1}^T |\hat{p}_t - p_t| \quad (8)$$

$$RMSE = \sqrt{\frac{\sum_{t=1}^T (\hat{p}_t - p_t)^2}{T}} \quad (9)$$

The following table compares the key indicators for the different model variants:

<sup>10</sup> We choose 2013 as reference year, as it is not part of the data sample used for estimating the supply curves.

<sup>11</sup> We consider Norway as a whole due to data availability. Especially hydro inflow data for the Norwegian bidding areas was not available.

Table 5: MAE and RMSE (in €/MWh) of the electricity prices for the model variants.

	$JMM - WV^{unif}$	$JMM - WV^{step} (1)$	$JMM - WV^{step} (2)$	$JMM - WV^{step} (3)$
Correlation	0.42	0.71	0.70	0.77
MAE	5.71	3.49	3.47	3.27
RMSE	7.51	5.13	5.27	4.72

The MAE and the RMSE of the electricity prices for the model variants indicate that the implementation of the stepwise supply curves improves substantially the model fit. And also the correlation between the historical values and the model variants of  $JMM - WV^{step}$  is better than for the former model  $JMM - WV^{unif}$ . Thereby the model specification (3) including the kink in the hydro supply function performs best according to all three metrics.

Figure 6 shows the hourly observed prices (Reality 2013) and the simulated prices of the former model variant ( $JMM - WV^{unif}$ ) and the adjusted model variant ( $JMM - WV^{step} (3)$ ).

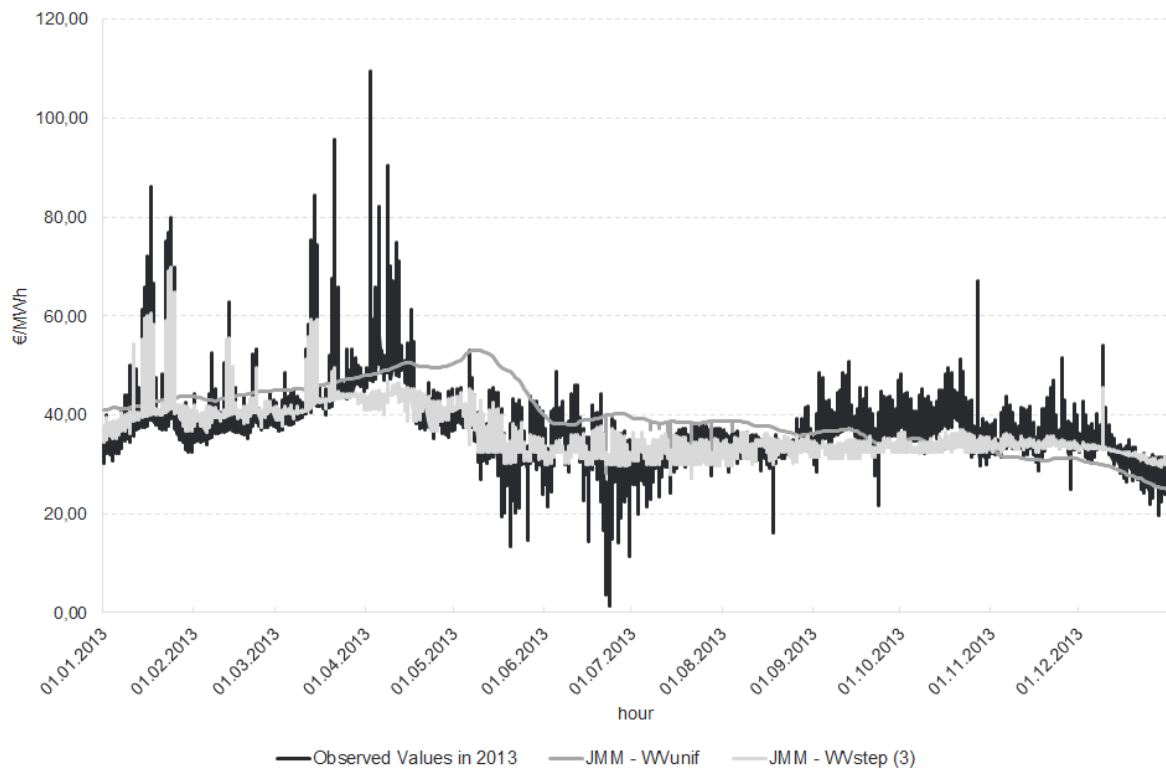


Figure 6: Simulated Norwegian electricity prices compared to historical values.

While the prices in both specifications follow the seasonal pattern of the observed prices over the year, hourly prices are more fluctuating in the new model. This is the key benefit of considering the different opportunity costs of hydro reservoirs in Norway. However the hourly comparison reveals that also the new model variant is not fully capable to capture the jumps and troughs of the Norwegian electricity prices in 2013. The remaining differences between observed and simulated prices can be partly explained by general characteristics of fundamental models.



Strategic bidding possibly applied by some producers is, for example, not considered. Given limited data availability for 2013, the modelling furthermore is not able to reflect detailed unavailabilities of power plants or interconnectors.

## 6 Conclusion

Although the modelling of hydro reservoir operation has been addressed repeatedly in research, little has been published on simplified representations of hydro power plants in large scale electricity system models. Therefore we propose a novel approach using econometric model specifications to improve the representation of hydro reservoirs within fundamental models.

The paper at hand formulates four different hypotheses about the hydropower supply curves and tests these empirically. Different considerations about endogeneity and non-linearity lead to the construction of three different model specifications. Model (1) includes both linear and interaction terms yet neglects possible non-linearities in the supply curves. Outliers potentially causing non-linearities are removed in model (2) whereas model (3) includes an additional variable to allow a kink in the supply curve. The three different model variants are applied to Norwegian data for the period 2016 to 2018. The statistical fit is very satisfactory given the parsimonious nature of the developed model specifications and the estimated coefficients are significant and confirm the formulated hypotheses. Therefore the model variants are implemented within the large-scale electricity market model JMM. The implementation provides significant improvements compared to earlier model specifications with just one single water value for all hydro reservoirs in one area.

The developed modelling approach offers the clear advantage that no detailed data about reservoir characteristics are needed and that calculation times remain unaffected by the enhanced modelling approach. Yet, the chosen approach might be less advantageous compared to other models when simulating future years. As the econometric model is estimated using historical data, structural changes in the future may lead to bad performances. For example, if coal-fired power plants are no longer setting the relevant opportunity cost, the model needs at least adjustments in the parameters in order to provide reasonable results. Another drawback is that the method is only applicable for countries with a very high share of hydro reservoirs. Hence, modellers may choose to make use of a computationally more burdensome approach. Still, if the aim is to simulate Europe's energy system with a near to mid-term horizon and if the focus is more on interdependencies between the hydro-dominated Scandinavian markets and the continental ones, the presented implementation might be quite advantageous compared to other existing models.

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