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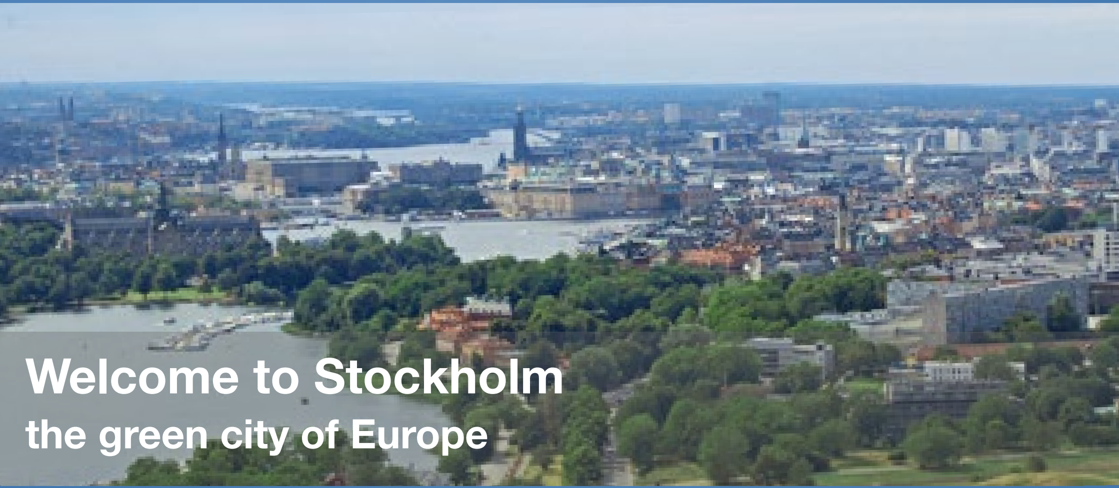

Multi-market unit-commitment and capacity reserve prices in systems with a large share of hydro power: a case study

André Ortner, Christoph Graf

***Abstract*—In line with the liberalisation of national spot markets within the European Union also the introduction of market-based reserve management can be observed in many countries. Whereas spot markets and their related products have been extensively analysed, the amount of literature focusing on the analysis of reserve markets and especially their interaction with other markets is rather scarce. This paper extends prior work on the economic equilibrium of spot and reserve markets with a special focus on markets that are characterised through a large share of hydro power. We theoretically discuss crucial factors determining the unit-commitment decision of generators by explicitly considering the interrelation of their decisions. Taking these effects into account we reflect on the economic equilibrium between spot and reserve markets. To test our hypotheses we developed a linear program with a detailed representation of the secondary control energy market design currently implemented in Germany/Austria. We use this model to derive integrated market outcomes of both the spot and balancing market. The proposed approach is applied to the Austrian power market; A market which is characterized by a large share of run-off river generators and pumped hydro storages. The results show that hydro power has a significant influence on the capacity reserve prices.**

***Index Terms*—Balancing markets, Spot markets, Pumped hydro storage, Fundamental electricity model**

NOMENCLATURE

A. Indices

$t \in T$	Index (set) of all hours of the planning horizon.
$\zeta \in \mathcal{Z}$	Index (set) of control areas $\mathcal{Z} = \{AT, DE\}$.
$\tau \in \mathcal{T}$	Index (subsets) of hour intervals $\tau(\mathcal{Z}) = \{\{wD, wN, WE\}, \{HT, NT\}\}$, where $\tau(AT) = wD$: weekdays, $\tau(AT) = wD$: weeknights, $\tau(AT) = WE$: weekends, $\tau(DE) = HT$: day time (workdays), $\tau(DE) = NT$: night time (incl. weekends).
$g(\zeta) \in \mathcal{G}$	Index (set) of all generation units dedicated to the control zone ζ.
$i(\zeta) \in \mathcal{G}$	Index (subset) of thermal generation units dedicated to the control zone ζ.
$j(\zeta) \in \mathcal{G}$	Index (subset) of hydro (storage) generation units dedicated to the control zone ζ.

André Ortner is with the Energy Economics Group, Technical University of Vienna, Gusshausstrasse 25-29/370-3, 1040 Vienna, Austria (e-mail: ortner@eeg.tuwien.ac.at)

Christoph Graf is with the Faculty of Business, Economics and Statistics, University of Vienna, Bruenner Strasse 72, 1210 Vienna, Austria (e-mail: christoph.graf@univie.ac.at)

B. Parameters

$n(\zeta)$	Number of thermal plants in control area ζ.
$m(\zeta)$	Number of hydro (pump-)storages in control area ζ.
$\overline{Q}_g$	Maximum technical power output of generation unit g, in MW.
$\overline{Q}_j^T$	Maximum technical turbining power of unit j, in MW.
$\overline{Q}_j^P$	Maximum technical pumping power of unit j, in MW.
$\overline{SC}_j$	Maximum technical storage capacity of hydro storage unit j, in MWh.
ϕ_{jt}	Storage inflow of hydro storage unit j in hour t, in MW.
σ_{jt}	Storage spillover of hydro storage unit j in hour t, in MW.
$\pi_{j\tau}^{sec}$	Share of reserved storage capacity for the delivery of balancing energy from hydro storage j within the time period τ in the secondary balancing market.
$\pi_{j\tau}^{ter}$	Share of reserved storage capacity for the delivery of balancing energy from hydro storage j within the time period τ in the tertiary balancing market.
c_{gt}^{spot}	Marginal cost of generation unit g in hour t, in €/MWh.
$c_{g\tau}^{sec}$	Marginal cost bid of generation unit g in time period τ in the secondary balancing market, in €/MWh.
$c_{g\tau}^{ter}$	Marginal cost bid of generation unit g in time period τ in the tertiary balancing market, in €/MWh.
η_j^{turb}	Turbining conversion efficiency of (pumped) hydro storage unit j.
η_j^{pump}	Pumping conversion efficiency of pumped hydro storage unit j.
D_t^{spot}	Residual spot market electricity demand in hour t.
$D_{\tau\zeta}^{sec,C}$	Reserve demand of secondary balancing market for time period τ and in control zone ζ.
$D_{\tau\zeta}^{sec,E}$	Power demand of secondary balancing market in each hour of time period τ and in control zone ζ.
$D_{\tau\zeta}^{ter,C}$	Reserve demand of tertiary balancing market for time period τ and in control zone ζ.
$D_{\tau\zeta}^{ter,E}$	Power demand of tertiary balancing market in each hour of time period τ and in control zone ζ.

C. Variables

q_{gt}^{spot}	Power generation of unit g in hour t in the spot market, in MW.

$q_{jt}^{T,spot}$ Turbining power of storage unit j in hour t in the spot market, in MW.
$q_{jt}^{P,spot}$ Pumping power of storage unit j in hour t, in MW.
$q_{jt}^{T,sec}$ Turbining power of storage unit j in hour t in the secondary balancing market, in MW.
$q_{jt}^{T,ter}$ Turbining power of storage unit j in hour t in the tertiary balancing market, in MW.
SC_{jt} Storage capacity of storage unit j in hour t, in MWh.
$Q_{g\tau}^{sec}$ Reserved capacity of generation unit g for time period τ in the secondary balancing market, in MW.
q_{gt}^{sec} Called power of generation unit g in each hour of time period τ in the secondary balancing market, in MW.
$Q_{g\tau}^{ter}$ Reserved capacity of generation unit g for time period τ in the tertiary balancing market, in MW.
q_{gt}^{ter} Called power of generation unit g in each hour of time period τ in the tertiary balancing market, in MW.

D. Lagrange Multipliers

p_t^{spot} Dual variable of the spot market demand constraint and price in €/MWh paid to the generators.
$pC_{\tau\zeta}^{sec}$ Dual variable of the secondary balancing market capacity demand constraint and price in €/MW/h paid to the participating generators during time period τ and in the control area ζ.
$pC_{\tau\zeta}^{ter}$ Dual variable of the tertiary balancing market capacity demand constraint and price in €/MW/h paid to the participating generators during time period τ and in the control area ζ.
$pE_{\tau\zeta}^{sec}$ Dual variable of the secondary balancing market energy demand constraint and price in €/MWh paid to the participating generators during time period τ and in the control area ζ.
$pE_{\tau\zeta}^{ter}$ Dual variable of the tertiary balancing market energy demand constraint and price in €/MWh paid to the participating generators during time period τ and in the control area ζ.

I. INTRODUCTION

THE particular characteristics of power systems rise the need for a balance between generation and consumption in every single point in time. Due to the fact that both generation and consumption are to some extent uncertain, a specified amount of back-up capacity has to be reserved in order to meet this requirement. In European's power markets the Transmission System Operators (TSOs) are responsible for the procurement of this back-up capacity. According to the grid code of the European Network for Transmission System Operators (ENTSO-E [1]) the necessary reserve capacity are divided into three different products, namely primary, secondary and tertiary capacity reserve. Those products differ in their time necessary to be operational.

Primary reserve are provided by the largest power plants within each country and is instantly available in case of small balance deviations that causes a frequency drop or peak, respectively, higher than 10mHz. This is done automatically by decentralized controller that are implemented within the power plants. In case of a balance deviation all power plants within the ENTSO-E transmission grid participate in providing this back-up. Secondary reserve are automatically activated within the control zone that caused the deviation in case the imbalance lasts longer than 30 seconds. All capacity offering secondary reserve capacity has to reach its dedicated power output at a maximum time of 5 minutes in order to release the primary reserve capacity. In a third step tertiary reserve capacity can be activated by the local TSO to release secondary reserve capacity as well. The maximum time span for tertiary reserve capacity to reach their dedicated power output is 15 minutes.

In order to be a contemplable reserve capacity provider, power plants need to fulfill a number of technical requirements, mostly with regard to their capability to change their power output accordingly to the predefined time frames in the several reserve products. In Austria and Germany those requirements are stated in the prequalification guidelines of the local TSOs ([2], [3], [4], [5], [6]). An important feature of those guidelines is the discrimination of hydro power units and thermal units in the case of the provision of secondary reserve power. It is stated that all thermal power units obliged to contribute a certain amount of secondary reserve capacity have to be online during this time ([7]). For hydro power units this is not the case. This highlights the extraordinary role of hydro power in the provision of reserve capacity and makes it interesting to study power systems with a large share of hydro power.

The current balancing markets all over Europe do not only differ in their mix of participating power plants, but also in their design [8]. On the one hand different reserve procurement horizons are defined. Starting from monthly tenders, we can also find weekly, four-hourly, or even hourly auctions for reserve capacity depending on the market product. The applied auction designs range from discriminatory to unique pricing models or combinations of both models. Against this background and the fact that in many markets the number of market participants in the balancing market is still small, the complexity in balancing power markets makes it difficult to analyze those markets and to interpret prices. Furthermore, the TSOs all over Europe start building coordinated balancing areas, or even merge their control zones (i.e. IGCC [9]) by following the goal of implementing the Network Code on Electricity Balancing (EB) [10] in order to further develop the EU internal electricity market. This development will deeply change Europeans balancing energy markets and thus also rise the need for a detailed analysis of the functioning of those markets.

Last but not least the increasing share of renewable energies in European power markets, especially volatile generation like wind and solar power, and the intensified participation of demand side units in balancing energy markets make it necessary to study the interaction of spot markets with balancing energy markets.

There are a number of literature concerning the analysis of balancing markets that can be categorized according to the following lines: The first part of literature is based on *physical*

models, considering the technical constraints of power systems in detail and aim for total cost minimization in order to get insights into the unit commitment and power flows. Prices from cost minimization models follow a least cost approach based on (nodal) pricing and physical constraints. However, prices sometimes stem from a regulatory policy regime. However, complex pricing schemes are mostly ignored by this approach.
The second line of literature focuses on the analysis of balancing market from a more theoretical perspective. This comprises analyses on what auction design should be chosen, what implications on cost-efficiency they might have and clarify what opportunities and incentives for strategic behavior exist (e.g. [11], [12], [13]).
The third line of literature is based on *market* models aiming for deriving market prices in balancing markets ([14], [15]). Those literature mainly focus on marginal reserve energy prices but do in most cases not adequately consider the complex pricing schemes of currently implemented market designs.
Recently, there have been not much theoretical as well as empirical work on the detailed design of balancing markets, namely, considering the complex pricing rules and interactions between several markets. However there are some work ([16], [17], [18], [19], [20]) aiming to analyze the interactions of spot and balancing energy markets from different perspectives.
In [19], [18], [20] the theoretical perspective are being taken and some significant simplifications are made in order to derive analytic conclusions. In [16] an iterative LP-model approach is being used to estimate the unit-commitment decision of thermal units. [17] develops an innovative approach considering multi-area complex pricing schemes although the focus is not on balancing market prices in detail and the effect of hydro power on such systems are not analyzed.
To the best of our knowledge there are no literature taking into account the complex pricing schemes of current implemented market designs, the interactions of several market segments and the influence of hydro power on the resulting prices.
In a first step, this paper elaborates on the question what power plants are most efficient in providing balancing capacity and what effect the market integration of power systems with a large share of hydro and thermal dominated power systems might have in terms of reserve capacity prices. In section II the used model and corresponding assumptions are described in detail. Section III then provide results on the balancing market zones of Germany and Austria. In section IV conclusions from the case study are drawn.

II. Model description and assumptions

The used model approach is based on a linear formulation and minimizes the variable costs in both the spot- and the balancing energy markets simultaneously. It is assumed that all participants can perfectly forecast all future demands. With regard to the market design we implemented all possible block offers regarding positive secondary and tertiary balancing energy that can be placed in the Austrian and German balancing energy markets. Our analysis is based on unit bidding rather than portfolio bidding and contains separated rules for hydro power units (e.g. they do not have to be online in the spot market when providing secondary reserve) are implemented. Primary balancing energy is assumed to be positive and negative for the same part and is not further considered within this paper. We did not discriminated the power units regarding their technical capabilities and assumed that all units are able to provide reserve capacity. Additional variable generations costs incurred due to the participation in the control energy market (e.g. O&M, computer linking to TSO) are neglected.
The capacity and energy prices of the balancing energy markets are an endogenous result of the model. The amount of reserve capacity bid in the market and calls of reserve energy are determined exogenous according to actual data. Power plants with reserved capacity have to be online in order to be able to provide this energy quickly.
As the Austrian-German market are the majority of time operated with any network congestions we do not consider network constraints. We solely allocate forecast errors to deviations on the demand side and do not consider forecast errors in the generation of RES as well as outages of conventional generators.
Given the currently low volume of intra-day offers compared to the volume in the day-ahead market we neglect the intra-day market in the current model setting.

The objective function is defined as

$$\min \sum_{t \in T} \left(C_t^{spot} + \sum_{\zeta \in \mathcal{Z}} C_{t\zeta}^{bal} \right) \tag{1}$$

whereas

$$C_t^{spot} = \sum_{i=1}^{n} c_{it}^{spot} \cdot q_{it}^{spot}, \quad \text{and} \tag{2}$$

$$C_{t\zeta}^{bal} = \sum_{i(\zeta)=1}^{n(\zeta)} c_{it}^{sec} \cdot q_{it}^{sec} + \sum_{i(\zeta)=1}^{n(\zeta)} c_{it}^{ter} \cdot q_{it}^{ter} \tag{3}$$

are the total variable cost of generation in the spot and balancing market, respectively. In (2) and (3) the assignment of generators to control zones is explicitly represented through the dependency of the indices i and n from the control zone index ζ. However, the spot market are considered as a single market and therefore comprises generators from all control zones. For the sake of simplicity we further omit the assignment to control zones and assume that each plant is assigned to a certain zone. Since we do not consider strategic behavior, we remove one degree of freedom via assuming that the marginal costs in all markets are the same.

$$c_{it}^{spot} = c_{it}^{sec} = c_{it}^{ter}, \quad \forall i, t \tag{4}$$

The constraints of the thermal units are

$$q_{it}^{spot}, Q_{i\tau}^{sec}, q_{it}^{sec}, Q_{i\tau}^{ter}, q_{it}^{ter} \geq 0, \tag{5}$$

$$0 \leq q_{it}^{spot} + Q_{i\tau}^{sec} + Q_{i\tau}^{ter} \leq \overline{Q}_i, \quad \text{and} \tag{6}$$

$$q_{it}^{spot} \geq Q_{i\tau}^{sec}, \quad \forall i, t, \tau. \tag{7}$$

Equation 6 ensures that the capacity dedicated to provide reserves limit the maximum available capacity in the spot market. The constraints for the hydro storage generation units are illustrated in the following.

$$q_{jt}^{T,spot}, q_{jt}^{T,sec}, q_{jt}^{T,ter}, q_{jt}^{P,spot}, Q_{j\tau}^{sec}, Q_{j\tau}^{ter} \geq 0, \quad \forall j,t,\tau. \quad (8)$$

$$q_{jt}^{spot} = q_{jt}^{T,spot} - q_{jt}^{P,spot}, \quad \forall j,t. \quad (9)$$

$$q_{jt}^{T,spot} + q_{jt}^{T,sec} + q_{jt}^{T,ter} \leq \overline{Q}_j^T, \quad q_{jt}^{P,spot} \leq \overline{Q}_j^P, \quad \forall j,t. \quad (10)$$

$$Q_{j\tau}^{sec}, Q_{j\tau}^{ter} \leq \overline{Q}_j^T, \quad \forall j,\tau. \quad (11)$$

$$\eta^{turb} \cdot \left(\pi_{j\tau}^{sec} \cdot Q_{j\tau}^{sec} + \pi_{j\tau}^{ter} \cdot Q_{j\tau}^{ter}\right) \leq SC_{jt} \leq \overline{SC}_j, \quad \forall j,t,\tau. \quad (12)$$

In the current model setting it is assumed that storages do have to be preparted that their capacity bid are called upon 100 per cent of reservation time, thus π^{sec} and π^{ter} are set to 1 in the current model setting.

$$SC_{j,t+1} = SC_{jt} - \eta^{turb} \cdot \left(q_{jt}^{T,spot} + q_{jt}^{T,sec} q_{jt}^{T,ter}\right) + \frac{1}{\eta^{pump}} \cdot q^{P,spot} + \phi_{jt} - \sigma_{jt}, \quad \forall j,t. \quad (13)$$

$$0 \leq \sigma_{jt} \leq \phi_{jt}, \quad \forall j,t. \quad (14)$$

$$SC_{j,1} = SC_{j,end}, \quad \forall j. \quad (15)$$

$$SC_{jt} \geq \eta_{jt}^{turb} \cdot q_{jt}^{T,spot}, \quad \overline{SC}_j - SC_{jt} \geq \frac{1}{\eta_{jt}^{pump}} \cdot q_{tj}^{P,spot} \quad \forall j,t. \quad (16)$$

Constraints 17 to 18 ensure that the reserved capacity per unit and procurement period always have to be the maximum of the actual called balancing power.

$$q_{it}^{sec} \leq Q_{i\tau}^{sec}, \quad q_{it}^{ter} \leq Q_{i\tau}^{ter} \quad \forall i,t,\tau. \quad (17)$$

$$q_{jt}^{T,sec} \leq Q_{j\tau}^{sec}, \quad q_{jt}^{T,ter} \leq Q_{j\tau}^{ter} \quad \forall j,t,\tau. \quad (18)$$

Finally, the demand constraints in the several markets are defined in equation 19 to 23. The variables in brackets on the right side of the equation mark the dual variables of the corresponding equation.

$$\sum_{i=1}^{n} q_{it}^{spot} + \sum_{j=1}^{m} q_{jt}^{spot} \geq D_t^{spot} \quad \forall t. \quad (pD_t^{spot}) \quad (19)$$

$$\sum_{i(\zeta)=1}^{n(\zeta)} Q_{i\tau}^{sec} + \sum_{j(\zeta)=1}^{m(\zeta)} Q_{j\tau}^{sec} \geq D_{\tau\zeta}^{sec,C} \quad \forall \tau,\zeta. \quad (pC_{\tau\zeta}^{sec}) \quad (20)$$

$$\sum_{i(\zeta)=1}^{n(\zeta)} q_{it}^{sec} + \sum_{j(\zeta)=1}^{m(\zeta)} q_{jt}^{T,sec} \geq D_{\tau\zeta}^{sec,E} \quad \forall t,\zeta. \quad (pE_{t\zeta}^{sec}) \quad (21)$$

$$\sum_{i(\zeta)=1}^{n(\zeta)} Q_{i\tau}^{ter} + \sum_{j(\zeta)=1}^{m(\zeta)} Q_{j\tau}^{ter} \geq D_{\tau\zeta}^{ter,C} \quad \forall \tau,\zeta. \quad (pC_{\tau\zeta}^{ter}) \quad (22)$$

$$\sum_{i(\zeta)=1}^{n(\zeta)} q_{it}^{ter} + \sum_{j(\zeta)=1}^{m(\zeta)} q_{jt}^{T,ter} \geq D_{\tau\zeta}^{ter,E} \quad \forall t,\zeta. \quad (pE_{t\zeta}^{ter}) \quad (23)$$

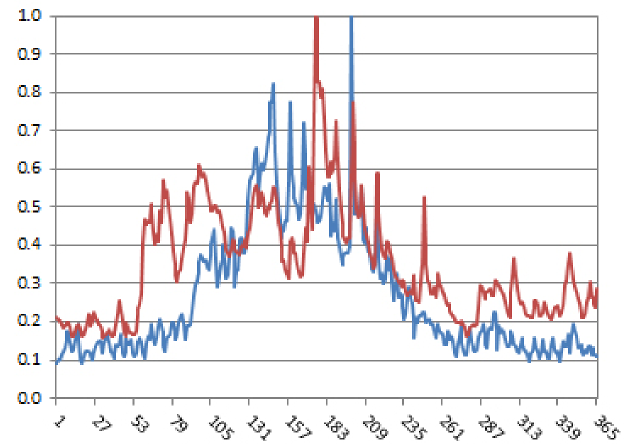

Fig. 1. Daily water inflow profiles dedicated to the German (blue) and the Austrian (red) hydro power units.

III. Numerical Example

To achieve first results the model has been calibrated for the power markets of Austria and Germany. With regard to the fact that the Austrian balancing power market has been liberalized since January 2012, our data input is based on the year 2012 as well in order to allow for comparability with the German balancing market, which have been liberalized in 2002.

The data of the power plants are taken from a detailed power plant database assembled from internal databases of our institutes which comprises all power plants above 1 MW and their corresponding technical data. To reduce the size and the complexity of the model we merged all thermal power plants with the same electrical conversion efficiency and did not consider their start-up costs and other fixed and variable operational costs, as well as their maintenance intervals or other detailed technical characteristics of their conversion technology. Furthermore, in those first scenarios we assumed that all plants are technically capable to deliver both secondary and tertiary reserve energy. In addition to the technical power plant data we used fuel data (p_{it}^{fuel}) from [21], the fuel-dependent emission coefficients (ϵ_i^{fuel}) and CO2-prices (p_t^{CO2}) from [22] to derive the hourly marginal costs

$$c_{it}^{spot} = \frac{1}{\eta_i^{el}} \cdot \left(p_{it}^{fuel} + \epsilon_i^{fuel} \cdot p_t^{CO2}\right) \quad (24)$$

of each generator. As can be seen in (24) we also did not consider any markups for location-specific transportation costs and possible taxes to the marginal costs.

The hydro power generators are divided into two groups. First, the run-off-river hydro units are modeled as must-run units with a given inflow based on historical water flows taken from [23]. The corresponding time series for Germany and Austria are based on weighted combinations of water flow data from the Danube and Rhein and are depicted in 1.

The run-off river power generation are derived via multiplying these profiles with the installed capacity.

Second, installed hydro storages and pump hydro storages in Germany and Austria are derived based on our internal power plant databases as well. Due to the fact that the number of storages significantly influence the computation time of optimization models we reduced the total number of storages considered in the model. We have done this via approximating the accumulated discharge curve (maximum accumulated power output over storage capacity) of all installed storage units per country through a discharge curve comprised by a smaller number of storage units. Furthermore, we assumed that the upper reservoirs are limited by their actual energy capacity and the lower reservoirs do not have any capacity restriction. We also did not consider any hydrological constraints and non-linearities stemming from the interconnection between several storage reservoirs and changing water fill levels. The hourly profile of the water inflows to the upper reservoirs are based on the inflows shown in 1 and are scaled to their actual yearly power generation of the storage units.

The power generation from renewable energies has been modeled as fixed must-run generation in the case of biomass/-gas units on the one hand and based on actual 2012 (day-ahead) forecasted power generation series of variable generation (e.g. wind and solar power) from the transmission system operators of Germany [3] [4] [5] [6] and Austria [2] on the other hand. Finally, the total power generated by renewables and run-off river hydro power are subtracted from the total electricity demand to derive the residual demand curve.

The electricity demand are based on the total hourly load curves available on the ENTSO-E database [1] and comprises besides the actual consumption of households the own consumption of power plants as well as grid losses. The electricity demand has also been corrected by the hourly power im-/export saldo [1] of Germany and Austria to adequately consider the influence of surrounding countries.

Data from requested quater-hourly balancing energy and procured secondary and tertiary reserve capacity during 2012 have been taken from [24] and [25], respectively. In order to operate the model on a hourly time resolution the quater-hourly data has been reduced to one value per hour. To replicate price peaks the highest value within each hour has been chosen. Within this paper we limited our focus on the analysis of the provision of positive balancing energy. However, the model extension to incorporate also negative balancing energy is straight forward.

In the following two model runs are presented to get insights in the unit-commitment of power plants and the corresponding (marginal) costs of reserve capacity reservation. The first model run is based on the assumption that Germany and Austria are divided in separated control zones and for this reason each power plant can only participate within the balancing markets within its own country. In principle, this is the situation that we are currently facing in those countries with the exemption that the tertiary balancing energy market has been opened for participants from Austria, however not the way round. In the second model run we assumed that there is just a single control zone with the accumulated balancing energy demand of the separated control zones and that all generators can participate without any restriction in the merged balancing energy markets.

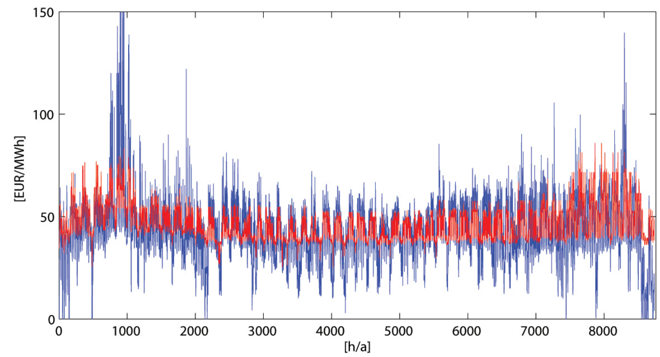

Fig. 2. Actual spot market price of EEX (*phelix-spot* in blue) and the modeled spot market price p_t^{spot} (red) during all hours of the year 2012.

Figure 2 shows the results of the spot market price and compares it two the actual market prices in Austria and Germany. It can be seen that our model on the one hand catches the medium value for most months very well and the overall correlation coefficient is 0.6294. Due to the fact that in the current version of the model no start-up costs are considered and therefore a cost-efficient down-regulation of conventional power generation occurs in times of an overproduction from renewable energies, this model do not reflect the daily price peaks and dips of the actual spot market price. Furthermore, as we do not consider maintenance intervals of power plants the model cannot replicate periods of higher prices which can be observed e.g. in the period from hour 800 to 1000. Also restrictions of combined heat and power (CHP) plants are not considered and thus the overall level of prices might be overestimated. However, the model is accurate enough to study the interaction of spot and balancing markets.

Figure 3 shows the marginal secondary reserve capacity costs of Germany, Austria and the merged control zone prices for each weekly procurement of 2012 during daytime from 08:00 to 20:00 and on working days. These costs are derived from the dual variables $pC_{\tau\zeta}^{sec}$ from equation (20) and can be interpreted as indicator for actual capacity costs of those markets. However, they do not replicate the actual capacity costs of the corresponding markets for two reasons. First, as has already been mentioned, the implemented market design within this model approach do not adequately reflect the current market designs within Germany and Austria, which consist of pay-as-bid auctions of spot market opportunity costs. Second, the derived prices from equation (20) contain in addition to the spot market (revenue)-losses the additional costs for the delivery of balancing energy as well. However, we can derive from figure 3 that Austria has on average significantly lower reserve capacity costs as Germany. When we compare figure 3 to figure 1 we can directly derive the influence of water inflows on the reservation price of capacity. Due to the fact that the relative share of installed hydro power capacity in Austria is much higher than in Germany, the observable effect on prices is quite stronger in Austria as well. The graph also shows a convergence of prices in times of low water inflows and thus again stresses the influence of hydro power production on price levels. The resulting prices from the model run with merged control zones are represented by the green plot. It can be seen that the run of the curve do not differ much from the prices in the separated control zone of Germany. This has three main reasons: First, and most importantly because the current model setting do not consider the occurrence of negative balancing energy which could lead to smoothing effects of the requested control energy in both zones and thus reduce overall costs. Second, also because of the negligence of negative balancing energy pump hydro storages cannot reveal their full potential and third, the absolute impact of Austria's hydro power capacity on the German market has to be seen in the light of the much larger electricity demand of Germany.

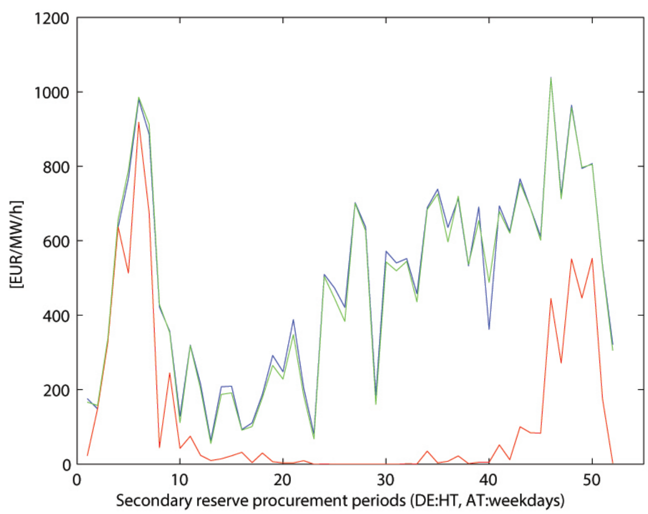

Fig. 3. Capacity costs of secondary reserve capacity during daytime and working days in Germany (blue), Austria (red) and the both control zones together (green).

Figure 4 shows the results of the model runs during night periods from 20:00 to 08:00 and the whole weekends. In principle, we can derive the same conclusions as from figure 3 with the difference that lower overall price levels can be observed during night time and weekends. Based on the fact that we analyze positive capacity reserve prices this can be explained through the lower spot market price levels during those periods. This effect is slightly balanced due to the fact that the procurement periods also comprise the weekends and thus are longer which necessarily has to rise costs.

The tertiary reserve capacity prices are close to zero in all hours and periods of the year which can indeed also be observed in actual tertiary reserve capacity prices.

In figure 5 the results of the unit-commitment of generators in the German control zone are illustrated. The bars in the graph each mark one single generator in ascending order of

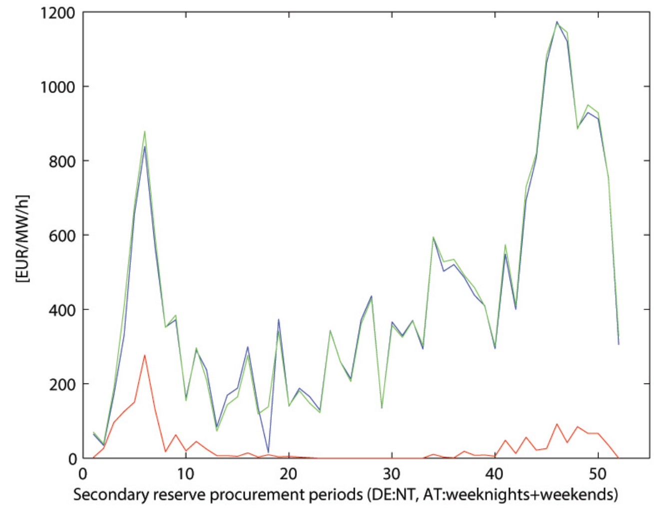

Fig. 4. Capacity costs of secondary reserve capacity during night time inclusive weekends in Germany (blue), Austria (red) and the both control zones together (green).

their marginal costs. The model has implemented 8 (pumped) hydro storage units in the German market which are all placed at the left side of the graph and are sorted according to their storage capacity in ascending order as well. The value of the blue bars is derived from the yearly production in the spot market of each generator divided by its total capacity and therefore represent the fullloadhours of each unit in the spot market. Similarly, the red bars results from the yearly accumulated (secondary) capacity reservation of each unit divided by their total capacity. Consequently, this is a measure of how many hours per year a certain unit have participated in the secondary balancing energy market. Additionally, the blue plot quantified through the secondary ordinate marks the total capacity[1] of each generator.

The graph illustrates the classification of thermal units (Nr. 9-50) according to their fullloadhours in the spot market into base-load, mid-load and peak-load units corresponding to the level of their marginal costs. The hydro storage units fall into two groups. The hydro storage units (Nr.1,2 and 8) are committed to provide reserve capacity most times of the year. It seems the storage capacity do not have an influence on this allocation, although it should be emphasizes that a number of other least-cost combinations of unit-commitments might exist. The second group comprises pump hydro storages. It can be observed that the more storage capacity, the more hours participate those storages in the balancing energy market. The only exemption is unit Nr.6 that is characterized through a high turbining capacity. Again this result has to be interpreted while having in mind that there might be other optimal allocations as well.

As stated in the introduction it can be seen in figure 5 that thermal units that are mid-load generators provide secondary reserve capacity. The involved units build a continuous band in the middle of the merit-order curve and the hours spend

[1] In case of hydro storages their turbining capacity

to provide reserves decrease with the distance from the generator in the middle of the band. This result conforms the theoretical discussion in the introduction and the results from [16].

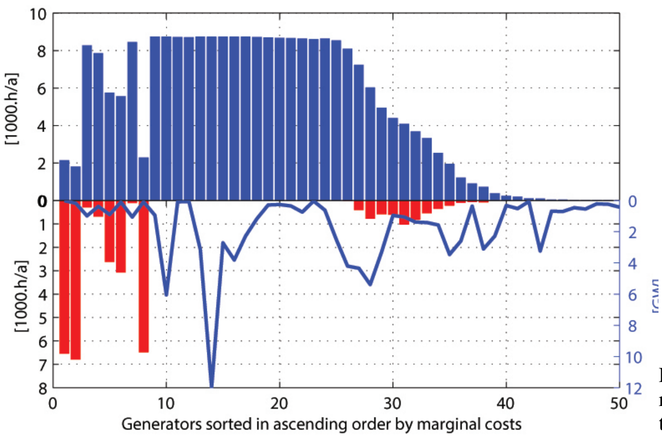

Fig. 5. Fullloadhours (blue bars) and number of hours per year of secondary reserve capacity reservation (red bars) for each generator in ascending order of their marginal costs and within the control zone of Germany. The corresponding capacity of each generation unit is shown in the blue plot.

Figure 6 illustrates the same scenario for the control zone of Austria. In this graph the first 11 units are hydro storages (Nr.1-6 are pump hydro storages and Nr.7-11 are hydro storages). Similarly to the situation in Germany, pumped hydro storages are the more committed to the provision of reserves the more storage capacity they have. In this case also the exemption from this observation holds that those units with the biggest turbining capacity do not provide much reserve capacity. In contrast to Germany the hydro storages in Austria do not provide large shares of capacity reserve, rather than running in the common spot market. Furthermore, it seems like that the base-load units in Austria provide a certain share of reserve capacity. However, the inspection of their fullloadhours makes clear that those units are operated de facto as mid-load units in the common spot market with Germany and therefore this observation also fits to the insight that in the case of thermal generators mid-load units most efficiently provide secondary reserve capacity.

Finally, figure 7 illustrates the results of the model run where both control zones were merged. It can be seen that in this model run the bandwidth of participating units get broader and thus the average hours of capacity reservation decreases. As stated before, because we do not consider the occurrence of negative balancing energy especially pump hydro storages (Nr. 3,5,7) tend to shift their capacity allocation to the spot market. In the case of hydro storages we can observe a tendency to the spot market the more storage capacity a certain unit have (Nr. 8,10,11,12,13). The obviously reason is that those storages have to make best use of their water inflow and therefore

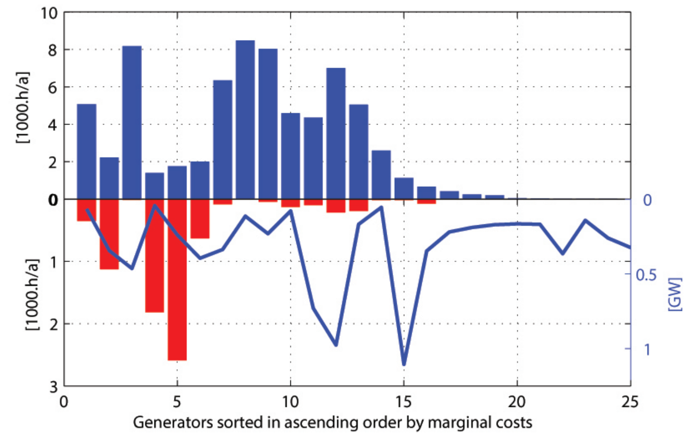

Fig. 6. Fullloadhours (blue bars) and number of hours per year of secondary reserve capacity reservation (red bars) for each generator in ascending order of their marginal costs and within the control zone of Austria. The corresponding capacity of each generation unit is shown in the blue plot.

tend to maximize their operational fullloadhours. Again, the thermal units comprise a continuous band of units situated in the middle of the merit-order curve. With regard to the higher amount of balancing energy of the merged control zones we can see an intensified commitment of thermal units in providing secondary reserves because the hydro units are better suited to balance fluctuations in the spot market demand.

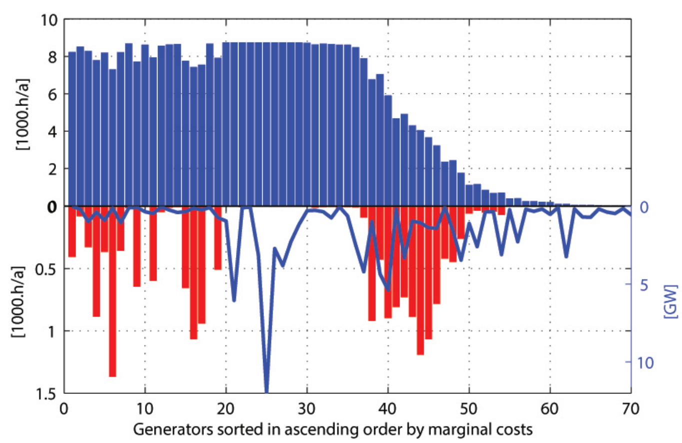

Fig. 7. Fullloadhours (blue bars) and number of hours per year of secondary reserve capacity reservation (red bars) for each generator in ascending order of their marginal costs and within the combined control zone of Germany and Austria. The corresponding capacity of each generation unit is shown in the blue plot.

IV. Conclusions

We presented a linear optimization model that is based on an integrated approach for the combined modeling of spot-and balancing markets in one stage. In particular, the focus has been put on the influence of hydro power units on reserve capacity prices and the analysis of the unit-commitment decision of generators within this context. To analyze those questions we calibrated our model to the German and the Austrian balancing energy market to elaborate on the different market outcomes. Those markets are characterized through considerable different shares of hydro units. It has been shown that a larger share of hydro units significantly influence the level of total secondary reserve capacity costs. We also derived some insights in the differing unit-commitment of hydro storage units versus pumped hydro storage units according to their maximum power output and their storage capacity. Furthermore, we found that mostly mid-load thermal units are cost-efficiently provide secondary reserve capacity. To study potential cost reductions of merged balancing energy markets also negative balancing energy demand has to be incorporated in the model in order to derive smoothing effects. Future work comprises the further development of the model to adequately implement the markets designs implemented in those countries.

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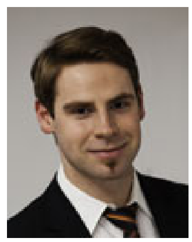

André Ortner is a research associate and PhD candidate at the Energy Economics Group at the Technical University of Vienna. He holds a master degree in electrical engineering (power engineering and energy economics) from Vienna University of Technology. His major field of research are the market and grid integration of renewable energies into Europeans power systems.

Christoph Graf is a research and teaching assistant at the faculty of Business, Economics, and Statistics at the University of Vienna. He holds a master degree in economics from the University of Vienna. His research comprises the analysis of market power in electricity markets and market effects stemming from the integration of volatile renewable energies.