

A Recovery Mechanism with Loss-Related Profits in a Day-Ahead Electricity Market with Non-Convexities

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Abstract--In wholesale electricity markets, unit commitment costs and capacity constraints create non-convexities which may bring about losses to some of the participating generation units. To keep the losing units in the market, a recovery mechanism that makes them whole is needed. In this paper, we present a recovery mechanism which compensates the units that incur cost-based losses with recovery payments, in order to ensure that they end up with positive profits. The profits resulting from the recovery payments are loss-related. More specifically, a losing unit will receive recovery payments to end up with final net profits that are set to a percentage, say α , of the losses. We evaluate this mechanism with a simulation-based methodology for certain values of the regulating parameter α , and the results show that this mechanism produces relatively low uplifts. We also comment on the pros and cons of this design and provide directions for further research.

Index Terms--Day-ahead electricity market, non-convexities, recovery mechanism.

I. NOMENCLATURE

A. Sets - Indices

U	Generation units, indexed by u
u	Generation unit index: $u \in U$
h	Hour (time period) index: $h \in \{0, 1, \dots, H\}$

B. Parameters

$P_{u,h}^g$	Price of energy offer for unit u , hour h
$P_{u,h}^r$	Price of reserve offer for unit u , hour h
NLC_u	No-load cost for unit u
SUC_u	Start-up cost for unit u
SDC_u	Shut-down cost for unit u
D_h	Demand (load) for hour h
R_h^{req}	Reserve requirement for hour h
Q_u^{\min}	Technical minimum for unit u
Q_u^{\max}	Technical maximum for unit u
R_u^{\max}	Maximum reserve availability for unit u
MU_u	Minimum uptime for unit u

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MD_u	Minimum downtime for unit u
ST_u^0	Initial status of unit u (at hour 0)
X_u^0	Number of hours unit u has been “ON” at hour 0
W_u^0	Number of hours unit u has been “OFF” at hour 0
<i>C. Decision variables</i>	
$G_{u,h}$	Total generation (output) for unit u , hour h
$R_{u,h}$	Reserve included in DAS for unit u , hour h
$ST_{u,h}$	Status (condition) for unit u , hour h . Binary variable. 1: ON(LINE), 0: OFF(LINE)
$Y_{u,h}$	Startup signal for unit u in hour h . Dependent binary variable. 1: Start-up, 0: No start-up
$V_{u,h}$	Shutdown signal for unit u in hour h . Dependent binary variable. 1: Shut-down, 0: No shut-down
$X_{u,h}$	Number of hours unit u has been ON at hour h since last start-up. Integer variable
$W_{u,h}$	Number of hours unit u has been OFF at hour h since last shut-down. Integer variable

II. INTRODUCTION

THIS paper considers the design of a joint energy/reserve, day-ahead electricity market with non-convexities. The market model is formulated as a *Mixed Integer Linear Programming* (MILP) problem that is solved every day, simultaneously for all 24 hours of the next day. The objective is to determine the unit commitment and the clearing of all the market commodities, namely energy and reserves, to minimize costs; with the term “reserves” we refer to the frequency-related ancillary services.

Non-convexities as a feature of electricity markets have been addressed in [1]-[14]. They are due to the commitment costs and capacity constraints of the generation units, which make the generators’ side in the market “lumpy” [13]. This lumpiness, if not reflected in the bids of the units, may lead to inefficient dispatching [13], [14]. With this in mind, throughout this paper, we consider multi-part bids that allow the generation units to explicitly express all their cost components (variable and commitment costs) in the day-ahead market. We also assume that the commodities are priced according to a uniform, marginal pricing scheme [15].

Due to the non-convexities, the revenues from participating in such a market design may not always be sufficient to cover the total costs of the generation units. To keep the losing units

in the market, a recovery mechanism is needed to compensate them and make them whole.

Our approach differs from other previous ones in that we consider the recovery mechanism as part of the existing market design. Rather than modifying the objective function of the *Day-Ahead Scheduling* (DAS) or the clearing prices, we do not directly interfere with the day-ahead market design and solution, and we therefore let the commodity prices be equal to the shadow prices of the respective market clearing constraints. Instead, we introduce a simple rule for recovery payments that will allow the generation units to have positive profits.

In this paper, which extends our preliminary works [5] and [6], we present a recovery mechanism that addresses the issue of non-convexities in joint energy/reserve, day-ahead electricity markets, and allows for positive profits that are related to the magnitude of the losses; hence we refer to this mechanism as a *recovery mechanism with loss-related profits*.

The remainder of this paper is organized as follows. In Section III, we present the model of a joint energy/reserve day-ahead market problem, and in Section IV, we describe the recovery mechanism under consideration. In Section V, we study a test case and we use a simulation-based methodology to evaluate the performance of this mechanism. The numerical results are presented in Section VI. Finally, Section VII concludes our work and provides directions for further research.

III. THE DAS PROBLEM

The design of the joint energy/reserve, day-ahead electricity market that we consider is based on Greece's day-ahead market paradigm [16]. To keep our analysis focused, we make several simplifying assumptions, without loss of the most important features of the real market design.

Specifically, we focus only on thermal plants, and do not consider hydro plants, renewable energy sources, and imports/exports, as they are subject to different market rules and scheduling processes. Also, we consider only one type of reserve (tertiary spinning and non-spinning reserve); an extension to include all types (primary, secondary, and tertiary) is straightforward. The demand and reserve requirements are exogenously determined by the system operator and are adjusted to take into account the absence of energy injection from hydro plants, renewable energy sources, and net imports. The producers submit energy offers for each hour of the following day, as a stepwise function of price-quantity pairs, with successive prices being strictly non-decreasing. For simplicity, and without loss of generality, we assume a single price bid for energy. The producers also submit reserve bids as price-quantity pairs and start-up, shut-down, and no-load costs.

The DAS problem can be formulated as a *Mixed Integer Programming* (MIP) problem as follows:

$$\begin{aligned} \min_{G_{u,h}, R_{u,h}, ST_{u,h}, Y_{u,h}, V_{u,h}} \quad & f_{DAS} = \sum_{u,h} P_{u,h}^g \cdot G_{u,h} + \sum_{u,h} P_{u,h}^r \cdot R_{u,h} \\ & + \sum_{u,h} ST_{u,h} \cdot NLC_u + \sum_{u,h} Y_{u,h} \cdot SUC_u + \sum_{u,h} V_{u,h} \cdot SDC_u \end{aligned} \quad (1)$$

$$\text{subject to:} \quad \begin{aligned} \sum_u G_{u,h} &= D_h & \forall h & (p_h^G) \\ \sum_u R_{u,h} &\geq R_h^{req} & \forall h & (p_h^R) \end{aligned} \quad (2) \quad (3)$$

$$G_{u,h} - ST_{u,h} \cdot Q_u^{\min} \geq 0 \quad \forall u, h \quad (4)$$

$$-G_{u,h} - R_{u,h} + ST_{u,h} \cdot Q_u^{\max} \geq 0 \quad \forall u, h \quad (5)$$

$$-R_{u,h} + ST_{u,h} \cdot R_u^{\max} \geq 0 \quad \forall u, h \quad (6)$$

$$(X_{u,h-1} - MU_u)(ST_{u,h-1} - ST_{u,h}) \geq 0 \quad \forall u, h \quad (7)$$

$$(W_{u,h-1} - MD_u)(ST_{u,h} - ST_{u,h-1}) \geq 0 \quad \forall u, h \quad (8)$$

$$Y_{u,h} = ST_{u,h}(1 - ST_{u,h-1}) \quad \forall u, h \quad (9)$$

$$V_{u,h} = ST_{u,h-1}(1 - ST_{u,h}) \quad \forall u, h \quad (10)$$

$$X_{u,h} = (X_{u,h-1} + 1)ST_{u,h} \quad \forall u, h \quad (11)$$

$$W_{u,h} = (W_{u,h-1} + 1)(1 - ST_{u,h}) \quad \forall u, h \quad (12)$$

$$ST_{u,0} = ST_u^0 \quad \forall u \quad (13)$$

$$X_{u,0} = X_u^0 \quad \forall u \quad (14)$$

$$W_{u,0} = W_u^0 \quad \forall u \quad (15)$$

with $G_{u,h}, R_{u,h} \geq 0$, $ST_{u,h}, Y_{u,h}, V_{u,h}$ binary, and $X_{u,h}, W_{u,h}$ integer, $\forall u, h$.

The objective function (1) minimizes the cost of providing energy and reserve as well as other commitment costs (start-up, shut-down, and no-load cost). Constraints (2) and (3) represent the market clearing constraints, i.e., the energy balance and the reserve requirements. Constraints (4)-(8) represent the generation units' technical constraints (technical minimum/maximum, reserve availability, minimum up/downtime). Equalities (9)-(12) define the binary and integer variables, namely the start-up/shut-down signals, and time counters of hours that a unit has been online/offline. Equalities (13)-(15) state the initial conditions of the units.

The nonlinearities that appear in constraints (7)-(12) can be replaced with linear inequalities, introducing auxiliary variables wherever necessary, thus obtaining an MILP problem. We then solve the MILP problem and fix the integer variables at their optimal values; this leads to a *Linear Programming* (LP) problem with meaningful shadow prices. Based on marginal pricing theory [15], the energy and reserve commodities are paid at the shadow price of the market clearing constraints (2) and (3) of the resulting LP problem, p_h^G and p_h^R , respectively.

IV. RECOVERY MECHANISM WITH LOSS-RELATED PROFITS

To elaborate, let VC_u be the *variable costs* for generating energy and keeping reserves, CC_u be the *commitment costs*, and REV_u be the *revenues* of generation unit u resulting from its participation in the day-ahead market. For the remainder of this paper, we will focus our attention on an arbitrary

generation unit; hence, for notational simplicity, we will omit subscript u . Let GPROF be the *gross profits* of an arbitrary generation unit, given by

$$\text{GPROF} = \text{REV} - [\text{VC} + \text{CC}] \quad (16)$$

From (16), it is obvious that a generation unit may incur losses, because its revenues (REV) from the commodities (energy and reserves) may not be sufficient to recover both variable and commitment costs (VC+CC). Even if the unit is explicitly compensated for the commitment costs, it may still incur losses. It may happen that in some hour(s) the unit is extra-marginal for energy, i.e., its energy offer is above the marginal price for energy, and yet the DAS solution schedules it at its technical minimum due to technical constraints, such as the technical minimum or the minimum up time. Consequently, the unit's revenues may be lower than its bids. If, in addition, the unit's offers were truthful, i.e., equal to the true costs, then its revenues would be lower than its variable costs, and the unit would incur losses for that hour. If the total losses over all 24 hours are substantial, the gross profits, GPROF, may end up being negative, which means that the unit will incur losses over the entire DAS horizon.

In this paper, we examine a mechanism which compensates a unit that incurs losses with *recovery payments* (RP), and allows it to keep *net profits* (NPROF) that are set to a fixed percentage say α , of its losses; hence the recovery mechanism associates the final profits with the losses (*loss-related profits*).

A necessary condition that must be met, in order for the unit to receive positive recovery payments, is that the gross profits are negative, i.e., that they correspond to *losses*, namely,

$$\text{GPROF} < 0 \Rightarrow \text{RP} > 0 \text{ and } \text{NPROF} = \text{GPROF} + \text{RP} \quad (17)$$

In this case, the final net profits will be

$$\text{NPROF} = \alpha [-\text{GPROF}] = \alpha [\text{VC} + \text{CC} - \text{REV}] > 0 \quad (18)$$

From (16), (17), and (18), the recovery payments that achieve these profits are:

$$\text{RP} = (1 + \alpha) [\text{VC} + \text{CC} - \text{REV}] \quad (19)$$

To the best of our knowledge such a design is not implemented in any of the existing market models.

As is the case with all market designs, one can find several pros and cons in this one, too. Firstly, note that this design creates an incentive for the units that exhibit losses to maximize their losses (in absolute values), in order to end up with higher profits. Even though this incentive seems to be peculiar, it leads to a particularly "nice" behavior. The units with high variable costs, which are also those with the highest probability to incur losses, have an incentive to bid as low as possible, in order to maximize their profits; hence this behavior may deter high prices, and lead to truthful bids for these units. On the downside, however, it may happen that these units end up with higher profits than the ones with lower variable costs.

The choice of parameter α (nonnegative) is a major design challenge for the regulator, as it controls the profits after the recovery. In fact, it may turn out to be hard to choose the value of this parameter, but this makes the work even more

challenging, and provides additional incentives to investigate the performance of such a design.

V. INPUT DATA AND METHODOLOGY

To evaluate the recovery mechanism with loss-related profits, we use as a test case a simplified model of the Greek electricity market with 10 units (U1-U10). Unit U1 is an aggregate representation of all available lignite units. Units U2, U3, U4 and U5 are combined cycle units, U6 and U7 are gas units, U8 and U9 are oil units, and U10 is a "peaker", i.e., a gas unit that can provide all its capacity for tertiary reserve. Tables I and II show the test case data that pertain to the generation units and the hourly energy and reserve requirements. Quantities are given in MW, and prices for energy and reserve bids in €/MWh. Minimum uptimes are given in hours, and commitment costs in €. The minimum uptimes are equal to the minimum downtimes. In the Greek market model, the objective function does not include the start-up cost; it only includes the shut-down cost with a value which is equal to the warm start-up cost to discourage DAS solutions that easily shut down units. Given this particularity, we assume that all units, except for U1 are initially offline; the aggregate unit U1 should be online to ensure a feasible solution.

TABLE I
UNITS' DATA (DAS INPUT)

Unit	\bar{Q}_u^g	\underline{Q}_u^g	\bar{Q}_u^r	C_u^g	MU_u	SUC_u	NLC_u
U1	3,800	2,400	250	35	24	1,500,000	20,000
U2	377	240	137	49	3	13,000	500
U3	476	144	180	52	5	10,000	300
U4	550	155	180	55	5	25,000	350
U5	384	240	144	57	3	15,000	500
U6	151	65	45	64	16	18,000	150
U7	188	105	45	65	16	27,000	250
U8	287	120	10	70	8	50,000	600
U9	144	60	20	72	12	24,000	300
U10	141	0	141	150	0	5,000	200

TABLE II
ENERGY DEMAND AND RESERVE REQUIREMENTS

h	1	2	3	4	5	6	7	8	9	10	11	12
D_h	4200	3900	3800	3700	3700	3600	4000	4300	4800	5200	5550	5500
R_h^{req}	450	400	400	400	400	400	450	500	550	600	600	600
h	13	14	15	16	17	18	19	20	21	22	23	24
D_h	5450	5450	5300	5000	4950	4900	5000	5200	5100	5000	4800	4500
R_h^{req}	600	600	600	550	550	550	550	600	600	550	500	500

In our earlier works [5] and [6], we sketch a simulation-based procedure to identify the bidding patterns of the market participants under various recovery mechanisms. In this paper, we shall use the same procedure to evaluate the impact of the new recovery mechanism with loss-related profits, on the market outcome. For the sake of completeness, we briefly mention the basic assumptions and steps.

The players (generation units) participate as potential price makers in a non-cooperative game with complete information

that is repeated for many rounds. We assume that the commitment costs are auditable and that the players submit truthful bids for their commitment costs. Also, for simplicity, and in order to remove any potential gaming with the reserve offers, we assume zero-priced reserve offers. Therefore, the only decision variable for the player is the bid for energy, which may range from the variable cost to the price cap, that is currently set at 150 €/MWh. Initially, each player places a bid for energy equal to its actual variable cost. In the following rounds, each player determines its bid as the price that maximizes its profits assuming that the other players' bids will remain unchanged. Since each player has the same objective of maximizing its profits, a new state of bids will be generated. The repetition of this game for many rounds reveals the bidding patterns of each player.

For the purposes of our analysis, we assume that all units, except U1 and U10, will participate in this game. Unit U1 will always have profits as it has the lowest cost, and unit U10 will have revenues mainly from the reserve market, since it will be the last unit to be dispatched for energy.

For the units with a profit-maximizing strategy (U2-U9), we assume that among multiple price offers that generate equal profits, they will choose to bid at the lowest price (risk-averse strategy). The bid that maximizes the profit is found by a “brute-force” procedure, exploring the set of prices from the cost to the price cap, with step of 1 €/MWh. In case of equal bids submitted by two or more units, the tie-breaking rule that we use favors the one with the lowest variable cost.

Let us now consider the measures that we use to evaluate the performance of this mechanism.

Assuming that all payments that are not associated with energy generation are actually paid by the retailers, who buy energy from the pool (and eventually by the consumers), as an

uplift (surcharge) on the energy clearing price, the key performance measure is the magnitude of this uplift. In this paper, the uplift has two components: the first is associated with the payments for reserve (ancillary services) and the second with the recovery payments. Evidently, a “good” design should generate low uplifts.

Other performance measures that reveal the incentive compatibility of the mechanism include the bidding patterns of the generation units, as well as their net profits.

VI. NUMERICAL RESULTS

We modelled the DAS problem presented in Section III using the mathematical programming language AMPL [17] and solved it with the ILOG CPLEX 10.1 optimization commercial solver on a Pentium IV 1.8GHz dual core processor with 1GB system memory (integrality was assigned at zero and all other parameters were set at their default values). The problem consists of 480 continuous, 1000 general integer, 730 binary decision variables, and 6158 constraints.

We tested several values of the regulating parameter α , and performed runs for a predetermined number of 50 rounds; the 50-round game consisted of 21,751 DAS problems, with a computational time of approximately 4 seconds on average for each DAS problem.

Fig. 1 shows the bidding pattern for an indicative value of the regulating parameter $\alpha = 0.50$ (50%) (for clarity of illustration purposes we omitted the last 10 rounds). Note that for the units U2-U9, which are considered to have a profit-maximizing strategy, the cost is ascending from U2 to U9 (the variable cost of each unit in Fig. 1 appears in the initial round 0). The average energy price is also shown (black line).

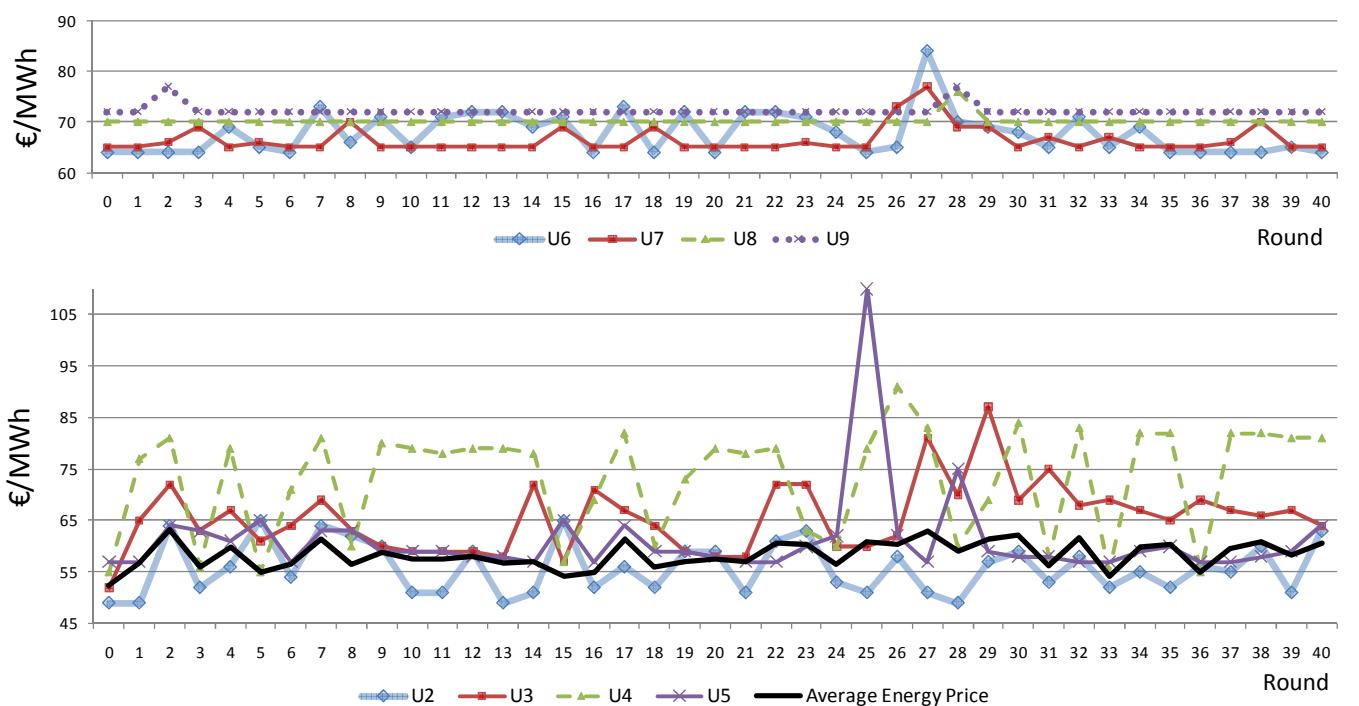


Fig. 1. Bidding patterns of the generation units for $\alpha = 0.50$ (50%)

TABLE III
AVERAGE AGGREGATE RESULTS

	Energy Payments (€/MWh)	Reserve Payments (€/MWh)	Recovery Payments (€/MWh)	Total Payments (€/MWh)	Total Uplift (€/MWh)	Total Uplift (% of En. Paym.)
α	(1)	(2)	(3)	(4) = (1) + (2) + (3)	(5) = (2) + (3)	(6) = (5)/(1)*100%
5%	57.396	0.532	0.164	58.092	0.696	1.213%
10%	57.396	0.532	0.171	58.099	0.703	1.225%
25%	58.140	0.575	0.209	58.924	0.784	1.348%
50%	58.626	0.632	0.247	59.505	0.879	1.499%
75%	58.628	0.632	0.288	59.548	0.920	1.569%
100%	57.937	0.572	0.382	58.891	0.954	1.647%
150%	58.129	0.623	0.454	59.206	1.077	1.853%
200%	60.149	0.709	0.424	61.282	1.133	1.884%

TABLE IV
AVERAGE BIDS OF GENERATION UNITS U2-U9

α	U2	U3	U4	U5	U6	U7	U8	U9
5%	58.57 (9.57)	62.43 (10.43)	72.86 (17.86)	59.43 (2.43)	69.43 (5.43)	65.86 (0.86)	70.00 (0.00)	72.00 (0.00)
10%	58.57 (9.57)	62.43 (10.43)	72.86 (17.86)	59.43 (2.43)	69.43 (5.43)	65.86 (0.86)	70.00 (0.00)	72.00 (0.00)
25%	57.35 (8.35)	64.73 (12.73)	72.08 (17.08)	61.29 (4.29)	68.04 (4.04)	66.51 (1.51)	70.12 (0.12)	72.37 (0.37)
50%	56.14 (7.14)	67.63 (15.63)	72.88 (17.88)	63.33 (6.33)	68.59 (4.59)	67.33 (2.33)	70.45 (0.45)	72.71 (0.71)
75%	56.14 (7.14)	67.63 (15.63)	72.88 (17.88)	63.33 (6.33)	68.67 (4.67)	67.33 (2.33)	70.45 (0.45)	72.71 (0.71)
100%	57.69 (8.69)	64.96 (12.96)	70.96 (15.96)	62.61 (5.61)	67.80 (3.80)	66.69 (1.69)	70.16 (0.16)	72.20 (0.20)
150%	57.37 (8.37)	66.41 (14.41)	71.39 (16.39)	62.65 (5.65)	68.57 (4.57)	66.45 (1.45)	70.24 (0.24)	72.31 (0.31)
200%	58.45 (9.45)	70.94 (18.94)	76.04 (21.04)	69.39 (12.39)	71.78 (7.78)	69.98 (4.98)	73.73 (3.73)	73.76 (1.76)
	49.00	52.00	55.00	57.00	64.00	65.00	70.00	72.00

TABLE V
AVERAGE PROFITS OF GENERATION UNITS U2-U9

α	U2	U3	U4	U5	U6	U7	U8	U9
5%	48,484	56,279	26,346	20,810	2,688	484	219	392
10%	48,484	56,279	26,357	20,834	2,736	667	437	784
25%	55,476	53,233	30,200	24,864	2,857	2,700	1,710	1,657
50%	63,378	52,404	31,515	27,077	4,050	3,936	4,275	3,301
75%	63,386	52,423	31,776	27,312	4,269	4,809	5,946	4,719
100%	56,681	51,660	30,201	23,935	3,840	6,589	7,423	6,989
150%	57,355	53,929	33,815	24,845	3,959	10,646	9,283	9,851
200%	74,458	64,450	44,687	32,762	7,236	13,041	10,464	11,186

In Fig. 1, we observe an “oscillatory” and rather speculative behavior of the units with low variable costs, which is due to their high profit margins. Units with higher variable costs, on the other hand, bid more conservatively, because they have low profit margins. The profit-maximizing strategy drives the units with low variable costs to bid high, in an attempt to become price-makers. This behavior is expected to appear independently of the recovery mechanism. The same strategy, in the herein case of loss-related profits, drives the units that exhibit losses to bid close to their costs, in order to maximize the losses and therefore the payments. This explains the more stable bidding pattern of the units with higher variable costs.

In Tables III-V, we present the main numerical results. Table III shows the average energy payments, reserve payments, recovery payments, and total payments in terms of €/MWh. The total uplift is reported in terms of both €/MWh and as a percentage of the energy payments. Table IV shows the average bids and in parenthesis the difference between the average bid and the variable cost (which is shown in the last

row for comparison reasons), as a measure of the units’ tendency to overbid. Table V shows the average profits (in €) of the units with a profit-maximizing strategy.

We summarize some key remarks:

1) The uplifts are quite low, less than or close to 1 €/MWh, which represents less than 2% of the energy payments (see columns 5 and 6 in Table III). This is a particularly nice result, especially if we take into account the fact that the largest part of the uplift refers to the reserve payments. Note that such low uplifts are observed even for particularly high values of the regulating parameter, e.g. for $\alpha = 2.00$ (200%).

2) The units with higher variable costs generally bid close to or even at their cost. This verifies the incentive compatibility of this mechanism to drive the units with high variable costs in bidding close to their cost.

3) The profits of the units with higher variable costs generally increase with the regulating parameter α . Since these units are inclined to bid low (close to or at their cost), in case they are dispatched, they exhibit losses, and therefore, their

loss-related profits are increasing with α .

4) The aggregate results for the values of $\alpha = 0.05$ (5%) until $\alpha = 1.50$ (150%) do not exhibit significant differences; the energy payments (in €/MWh) range from 57.4 to 58.6, and the total payments from 58 to 59.5. Also, the results for $\alpha = 0.05$ (5%) and $\alpha = 0.10$ (10%) are practically the same. The difference in net profits when $\alpha = 5\%$ and $\alpha = 10\%$ is too small in absolute terms to significantly change the bidding behavior of the units and hence the overall performance of the mechanism. Similar observations are made for the values 50% and 75%.

On the downside, it may happen that a unit with higher variable cost obtains higher profits than a unit with lower variable cost (e.g., compare the profits of U6 and U9). This reversal raises questions regarding the incentive compatibility of the mechanism; it is certainly a drawback of this design that needs to be considered. However, the selection of the parameter α , may limit this effect. Also, one should take into account that units with high variable costs will not always be dispatched; hence, one would expect that in the long-run the units with lower variable costs would end up with higher profits. Nevertheless, this behavior remains to be investigated in future works, and should be viewed in combination with the revenues from potential capacity payments.

VII. CONCLUDING REMARKS AND ISSUES FOR FURTHER RESEARCH

The preliminary results show that the recovery mechanism with loss-related profits performs quite well, in the sense that it produces low uplifts and, depending on the value of the regulating parameter α , allows for “reasonable” profits. Also, it does not lead to high prices, and induces the units with high variable costs to bid close or precisely at their cost.

Of course, like any other mechanism, this one, too, has its drawbacks. To investigate this further, many more tests and special comparative studies with other recovery mechanism designs need to be performed, such as the ones described in [5] and [6]; this is a subject of ongoing work by the authors.

To give a sense, the results for this particular test case show that the loss-related recovery mechanism that was introduced in this paper produces an aggregate outcome, in terms of uplift and total payments, which is comparable with the outcome of the regulated bid recovery mechanism presented in [6]. Also, if we consider a mechanism with loss-related profits but with an explicit compensation for the commitment costs, the results are much worse, compared to the results of the mechanism presented in this paper, which does not explicitly compensates for the commitment costs.

Finally, another subject of related ongoing research by the authors is the attempt to analytically solve for the jointly optimal bidding strategies of the profit-making units using game theoretic arguments. This is a very difficult task and can only be performed for very small “nominal” systems, similar to the duopoly electricity auction model (without fixed costs) investigated by [18].

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