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Recovery Mechanisms in Day-Ahead Electricity Markets With Non-Convexities—Part I: Design and Evaluation Methodology

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***Abstract*—In centralized day-ahead electricity markets with marginal pricing, unit commitment costs and capacity constraints give rise to non-convexities which may result in losses to some of the participating generating units. Therefore, a recovery mechanism is required to compensate them. In this paper, we present and analyze several recovery mechanisms that result in recovery payments after the market is cleared. Each of these mechanisms results in a different type and/or amount of payments for each participating unit that exhibits losses. We also propose a methodology for evaluating the bidding strategy behavior of the participating units for each mechanism. This methodology is based on the execution of a numerical procedure aimed at finding joint optimal bidding strategies of the profit-maximizing units. In a companion follow-up paper (Part II), we apply this methodology to evaluate the performance and incentive compatibility of the suggested recovery mechanisms on a simplified test case model of the Greek electricity market.**

***Index Terms*—Day-ahead market, electricity market modeling and simulation, non-convexities, recovery mechanism, unit commitment.**

NOMENCLATURE

A. Sets—Indices

h	Hour (time period) index: $h \in \{0, 1, \ldots, H\}$; H: time horizon; typically $H = 24$.
u	Generation unit index: $u \in U$; U: set of generation units.
b	Block bid index (for energy offers): $b \in \{1, \ldots, B\}$; B: number of blocks.

B. Parameters

System Energy/Reserve Requirements:

D_h^G	Demand for energy (load) for hour h.
D_h^R	Reserve requirement for hour h.

Generation Unit Technical/Economic Data:

$\underline{Q}_u^G$	Technical minimum for unit u.
$\bar{Q}_u^G$	Technical maximum for unit u.
$\bar{Q}_{u,b}^G$	Block maximum for unit u, block b.
$\bar{Q}_u^R$	Maximum reserve availability for unit u.
MT_u^{Up}	Minimum uptime for unit u.
MT_u^{Down}	Minimum downtime for unit u.
$P_{u,b,h}^G$	Price of energy offer for unit u, block b, hour h.
$P_{u,h}^R$	Price of reserve offer for unit u, hour h.
$C_{u,b}^G$	Cost of energy generation for unit u, block b.
C_u^R	Cost of reserve for unit u.
C_u^{SU}	Startup cost for unit u.
C_u^{SD}	Shutdown cost for unit u.
C_u^{NL}	No-load cost for unit u.

Initialization Parameters:

$X_u^{\mathrm{St},0}$	Initial status of unit u (at hour 0).
$Y_u^{\mathrm{On},0}$	Number of hours unit u has been "ON" at hour 0.
$Y_u^{\mathrm{Off},0}$	Number of hours unit u has been "OFF" at hour 0.

C. Decision Variables

$Q_{u,b,h}^G$	Total generation (output) for unit u, block b, hour h.
$Q_{u,h}^R$	Reserve for unit u, hour h.
$X_{u,h}^{\mathrm{St}}$	Status (condition) for unit u, hour h. Binary variable. 1: ON(line), 0: OFF(line).
$X_{u,h}^{\mathrm{SU}}$	Startup signal for unit u in hour h. Dependent binary variable. 1: Startup, 0: No startup.
$X_{u,h}^{\mathrm{SD}}$	Shutdown signal for unit u in hour h. Dependent binary variable. 1: Shutdown, 0: No shutdown.
$Y_{u,h}^{\mathrm{On}}$	Number of hours unit u has been ON at hour h since last startup (dependent integer variable).
$Y_{u,h}^{\mathrm{Off}}$	Number of hours unit u has been OFF at hour h since last shutdown (dependent integer variable).

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I. Introduction

ELECTRICITY market design has been a major challenge for both economists and engineers for the last two decades. The transition from monopolistic structures to deregulated markets has raised numerous questions on the design and the resulting incentives which to date have not had definite answers. Different designs have been proposed and implemented, but many issues remain open.

A. Background and Motivation

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 least-cost unit commitment and clearing of all market commodities, namely energy and reserves, where the term "reserves" refers to frequency-related ancillary services. The non-convexities are due to the commitment costs and capacity constraints of the generation units, which make the generators' side in the market "lumpy". Requesting from generators to submit energy-only bids, which do not reflect this lumpiness, can lead to market equilibria that are neither competitive nor efficient [1], [2]. 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 [3].

Non-convexities make marginal costs less than average variable costs. Marginal cost pricing can therefore fail to recover commitment costs, resulting in losses for some of the participating units. To compensate them for these losses, a recovery mechanism is needed. The standard practice for addressing this issue is based on the "revenue sufficiency guarantee" [4], according to which make-whole payments are assessed to the generators and the resulting costs are uplifted to the loads. In this paper, we look at several alternative recovery mechanism designs that result in recovery payments after the market is cleared (ex post), and we propose a methodology for evaluating them.

The first design that we examine lets the losing units keep a fixed percentage of their variable costs. A variant of this design is used in the Greek market. The second design lets the losing units keep a fixed percentage of their losses. The third design fully recovers their bids. This is the uplift payment scheme currently deployed by system operators in the US. Finally, we also look a variant of this design where the bids are recovered provided that they are within a certain set margin from their costs.

B. Literature Review

Non-convexities as a feature of electricity markets have been addressed in [5]–[23]. O' Neill *et al.* [5] model a market with indivisibilities as an MILP problem and use its optimal solution to create a *linear programming* (LP) problem by expanding the set of commodities to include any activities that are associated with the integer variables. Hogan and Ring [6] consider the unit commitment problem for a day-ahead electricity market and present a "minimum-uplift" pricing approach that focuses on non-convexities, taking into account the generation units' startup costs and technical minimum and maximum constraints. Bjørndal and Jörnsten [7] address the same problem, and propose a methodology which is based on the generation of a separating valid inequality that supports optimal resource allocation. Ruiz *et al.* [8] propose a primal-dual approach for pricing non-convexities, in an attempt to avoid uplifts. The above papers [5]–[8] refer to a numerical example in Scarf [9] that demonstrates the lack of a market-clearing price in a market with non-convexities. Sioshansi *et al.* [10] exploit the scheme in [5] to show that make-whole payments can help reduce surplus volatility and differences to some extent. Andrianesis *et al.* [11] describe a bid recovery mechanism, also based on the analysis in [5], which applies to the day-ahead market problem. In a preliminary version of this work, Andrianesis *et al.* [12] investigate the incentive compatibility of various recovery mechanisms on a market structure that is based on the Greek electricity market. Motto and Galiana [13] propose a price-based formulation that involves "augmented pricing," for an energy-only, single-period unit commitment problem. The same authors [14] study the coordination problem in energy-only markets with non-convexities. They establish a minimum input requirement, but do not consider any additional monetary uplifts. An uplift approach, in a different context than ours, is presented in [15] and [16]. Gribik *et al.* [17] consider alternative ways of defining uniform energy prices and calculate the associated impact on the energy uplift required to support the least-cost unit commitment and dispatch. The idea of a "convex hull pricing model" in [17] is further elaborated in [18] to reduce the uplift payments. Muratore [19] addresses the issue of non-convexities in a different context, and proposes a peak-load pricing scheme that can recover the fixed costs in a yearly period for an energy-only market. Alternative pricing approaches have also been proposed in [20]–[23].

Although the above literature proposes market designs that address non-convexities, it does not evaluate the incentive compatibility associated with these designs. Such an evaluation involves finding the optimal bidding strategy of each market participant. Depending on the interactions with other participants, this problem may fall into one of three categories [24]: 1) the participant acts as a price-taker (see e.g., [25]); 2) the participant acts as a price-maker (see e.g., [26]), trying to maximize his profit, assuming the other participants' bids are known and fixed; and 3) the participant tries to maximize his profit taking into account the other participants' strategies as well. The latter category aims at identifying market equilibria. Ventosa *et al.* [27] survey electricity market equilibrium models up to the early 2000s. Hobbs *et al.* [28] use an iterative scheme (diagonalization) to compute a market equilibrium, where in each iteration, each market participant solves a profit maximization problem, assuming that the other participants' bids remain fixed at the values of the previous iteration. De la Torre *et al.* [29] consider multi-period Nash equilibria and apply an iterative procedure to identify behavior patterns of the generation units; the units decide on the quantity to bid, while the price is determined by price quota curves. The problem formulation assumes a simple pricing rule according to which the market clearing price is the price of the last accepted production bid, without considering reserves or any recovery mechanism. A similar iterative procedure is also employed by Haghighat *et al.* [30], in an attempt to find Nash equilibria in joint energy/reserve markets, under a pay-as-bid pricing scheme, without considering the non-convexities of the unit commitment problem. Barroso *et al.* [31] present an MILP solution approach for finding a Nash equilibrium in strategic bidding in short-term energy-only electricity markets with equilibrium constraints. More recently, Hasan *et al.* [32] and Hasan and Galiana [33] address the issue of Nash equilibria for an energy-only electricity market, without taking into account unit commitment and associated costs, technical minimum, and inter-temporal constraints. Lastly, Sioshansi and Nicholson [34] debate on centrally committed versus self committed markets and characterize Nash equilibria for a stylized single-period symmetric duopoly. In the former design, the generators submit two part offers (energy and startup) and the recovery of their bids is guaranteed with make-whole payments.

To obtain equilibrium solutions, the above models either limit the players' bidding options or suppress important market structure features, such as discontinuities in the cost structure and inter-temporal effects. However, as the market design becomes more complicated, finding a Nash equilibrium becomes practically infeasible. Nevertheless, attempting to numerically find a Nash equilibrium by some iterative scheme can reveal insightful patterns of bidding behavior under the specific market rules, even if this scheme does not converge to a solution.

C. *Aim and Contribution*

Our aim in this paper, which builds on our preliminary work [11] and [12], is to: 1) present several recovery mechanisms that address the issue of non-convexities in joint energy/reserve, unit commitment-based day-ahead electricity markets, and 2) propose a methodology for evaluating the bidding strategy behavior of the participating units under each mechanism. The evaluation will provide insights on the incentive compatibility properties of these mechanisms.

Rather than modifying the objective function of the *day-ahead scheduling* (DAS) problem or the clearing prices, we do not directly interfere with the day-ahead market design and solution, so we let the commodity prices be equal to the shadow prices of the respective market clearing constraints. Instead, we introduce simple rules for recovery payments that will allow the generation units to have positive profits. These payments are settled after the day-ahead market is cleared; hence, they depend on the market outcome.

The advantage of this approach is that the dispatching and pricing of the commodities is still subject to the existing and well-established day-ahead market rules for co-optimizing energy and ancillary services. This approach can be particularly attractive to regulators, because proposals that change the pricing rules (e.g., the payment cost minimization based clearing format that some claim reduces the amount of payments, etc.) are often misguided, misunderstood or mistrusted by the market participants and prove to be a source of friction. Hence, keeping the widely-accepted marginal pricing scheme for the procured commodities is particularly important for the market.

D. *Paper Organization*

The remainder of this paper is organized as follows. In Section II we present the model of a joint energy/reserve day-ahead market problem that we use as a basis of our study. In Section III we address the need for a recovery mechanism, and we present several alternative recovery mechanisms. In Section IV we develop a numerical methodology for assessing the incentive compatibility of each mechanism. Finally, in Section V we draw our conclusions.

In a companion follow-up paper (Part II) [35], we apply the proposed numerical methodology that we develop in this paper on a simplified test case model of the Greek electricity market. We discuss the results and derive insights on the incentive compatibility of the recovery mechanisms under consideration.

II. Joint Energy/Reserve Day-Ahead Market Problem

We consider a typical design of the joint zonal energy/reserve day-ahead electricity market. An example of such a design is contained in [36]. To keep our analysis focused, we make several simplifying assumptions without loss of the most important features of a practical market design.

Specifically, we focus on thermal plants only; we do not consider hydro plants, renewable energy sources, and imports/exports. Also, we consider only one type of reserve, namely, tertiary spinning reserve; an extension to include other types of reserves (such as primary, secondary) is straightforward. The producers submit energy offers for each hour of the following day, as a stepwise function of price-quantity pairs, and reserve bids, as single price-quantity pairs. Current practices of system operators put substantially more restrictions on the submitted unit commitment costs than on the energy bids. The reason is that market power mitigation procedures are currently used only to mitigate the energy bids, but not the unit commitment bids. With this in mind, we assume that producers submit their true startup, shutdown, and no-load costs. Misstating the commitment costs could be examined in the context of market power mitigation methodologies. This could be an issue for further research.

We note that in practice, market and system operators know the true costs of the generators, since the market participants are obligated to submit cost information to them. These data include the heat rate curves that are used to calculate the incremental costs of the generators as well as the unit commitment costs. System operators have specific procedures and work with market participants to update these cost data on a periodic basis. They use these data to ensure that market participants do not exercise market power.

With these assumptions in mind, the DAS problem can be formulated as a *mixed integer programming* (MIP) problem as follows:

$$\min_{\substack{Q^G_{u,b,h},Q^R_{u,h}\\X^{\mathrm{St}}_{u,h}}} \left\{ \begin{array}{l} \sum_{u,b,h} P^G_{u,b,h}\cdot Q^G_{u,b,h} + \sum_{u,h} P^R_{u,h}\cdot Q^R_{u,h} \\ + \sum_{u,h} X^{\mathrm{SU}}_{u,h}\cdot C^{\mathrm{SU}}_u + \sum_{u,h} X^{\mathrm{SD}}_{u,h}\cdot C^{\mathrm{SD}}_u \\ + \sum_{u,h} X^{\mathrm{St}}_{u,h}\cdot C^{\mathrm{NL}}_u \end{array} \right\} \tag{1}$$

subject to : (shadow prices)

$$\sum_{u,b} Q^G_{u,b,h} = D^G_h \qquad \forall h \quad \left(\lambda^G_h\right) \tag{2a}$$

$$\sum_{u} Q^R_{u,h} \geq D^R_h \qquad \forall h \quad \left(\lambda^R_h\right) \tag{2b}$$

$$\sum_b Q^G_{u,b,h} \geq X^{\mathrm{St}}_{u,h} \cdot \underline{Q}^G_u \quad \forall u,h \quad (3a)$$
$$\sum_b Q^G_{u,b,h} + Q^R_{u,h} \leq X^{\mathrm{St}}_{u,h} \cdot \bar{Q}^G_u \quad \forall u,h \quad (3b)$$
$$Q^G_{u,b,h} \leq \bar{Q}^G_{u,b,h} \quad \forall u,h \quad (3c)$$
$$Q^R_{u,h} \leq X^{\mathrm{St}}_{u,h} \cdot \bar{Q}^R_u \quad \forall u,h \quad (3d)$$
$$\left(Y^{\mathrm{On}}_{u,h-1} - MT^{\mathrm{Up}}_u\right)\left(X^{\mathrm{St}}_{u,h-1} - X^{\mathrm{St}}_{u,h}\right) \geq 0 \quad \forall u,h \quad (4a)$$
$$\left(Y^{\mathrm{Off}}_{u,h-1} - MT^{\mathrm{Down}}_u\right)\left(X^{\mathrm{St}}_{u,h} - X^{\mathrm{St}}_{u,h-1}\right) \geq 0 \quad \forall u,h \quad (4b)$$
$$X^{SU}_{u,h} = X^{\mathrm{St}}_{u,h}\left(1 - X^{\mathrm{St}}_{u,h-1}\right) \quad \forall u,h \quad (5a)$$
$$X^{SD}_{u,h} = X^{\mathrm{St}}_{u,h-1}\left(1 - X^{\mathrm{St}}_{u,h}\right) \quad \forall u,h \quad (5b)$$
$$Y^{\mathrm{On}}_{u,h} = \left(Y^{\mathrm{On}}_{u,h-1} + 1\right) X^{\mathrm{St}}_{u,h} \quad \forall u,h \quad (5c)$$
$$Y^{\mathrm{Off}}_{u,h} = \left(Y^{\mathrm{Off}}_{u,h-1} + 1\right)\left(1 - X^{\mathrm{St}}_{u,h}\right) \quad \forall u,h (5d)$$
$$X^{\mathrm{St}}_{u,0} = X^{\mathrm{St},0}_u \quad \forall u \quad (6a)$$
$$Y^{\mathrm{On}}_{u,0} = Y^{\mathrm{On},0}_u \quad \forall u \quad (6b)$$
$$Y^{\mathrm{Off}}_{u,0} = Y^{\mathrm{Off},0}_u \quad \forall u \quad (6c)$$

with $Q^G_{u,b,h}, Q^R_{u,h} \geq 0, X^{\mathrm{St}}_{u,h}, X^{\mathrm{SU}}_{u,h}, X^{\mathrm{SD}}_{u,h}$ binary, and $Y^{\mathrm{On}}_{u,h}$, $Y^{\mathrm{Off}}_{u,h}$ integer, $\forall u, b, h$.

The objective function (1) minimizes the cost of providing energy and reserve as well as other commitment costs, namely, startup, shutdown, and no-load costs. Constraints (2) represent the market clearing constraints, i.e., the energy balance and the reserve requirements. The generation units' technical minimum/maximum, and the reserve availability constraints are given by (3); the minimum up/down-time constraints are stated by (4). To keep the formulation compact, we have not included any ramp constraints; such constraints can be easily included along with other additional constraints that may apply in any specific market design. Equalities (5) define the binary and integer variables, namely the startup/shutdown signals, and time counters of hours that a unit has been online/offline. Equalities (6) state the initial conditions of the units.

Nonlinear constraints (4) and (5) can be replaced by linear inequalities, which can be found in [36], to turn the above MIP problem into an MILP problem. If we solve that problem and fix the integer variables at their optimal values (marked with an asterisk), we obtain an LP problem in which constraints (4) and (5) have been replaced with the following equalities:

$$X^{\mathrm{St}}_{u,h} = X^{\mathrm{St}(*)}_u \quad \forall u,h \quad (7a)$$
$$X^{\mathrm{SU}}_{u,h} = X^{\mathrm{SU}(*)}_u \quad \forall u,h \quad (7b)$$
$$X^{\mathrm{SD}}_{u,h} = X^{\mathrm{SD}(*)}_u \quad \forall u,h. \quad (7c)$$

We can then use that LP to calculate the clearing prices of the energy and reserves, as the shadow prices of the market clearing constraints (2a) and (2b), λ^G_h and λ^R_h, respectively.

The DAS model presented above, for simplicity, assumes a single zone. It can be expanded to include multiple zones. Further, in some markets, like the Greek electricity market, the energy pricing scheme is zonal, whereas the reserve pricing scheme currently in use is a "maximum bid accepted" scheme. Alternatively, the zonal marginal pricing for both energy and reserves can be applied, as in [37], consistent with marginal pricing theory.

III. Proposed Recovery Mechanisms

As was mentioned in the introduction, the revenues from participating in the market described in the previous section are not always sufficient to cover the costs of the participating generating units.

To elaborate, let VC_u be the *variable costs* for generating energy and providing reserves, CC_u the *commitment costs*, BID_u the *bids*, and REV_u the *revenues* of generation unit u resulting from its participation in the day-ahead market. The above costs, revenues and bids are given by

$$\mathrm{VC}_u = \sum_{b,h} C^G_{u,b} \cdot Q^G_{u,b,h} + \sum_h C^R_u \cdot Q^R_{u,h} \quad (8a)$$
$$\mathrm{CC}_u = \sum_h X^{\mathrm{SU}}_{u,h} \cdot C^{\mathrm{SU}}_u + \sum_h X^{\mathrm{SD}}_{u,h} \cdot C^{\mathrm{SD}}_u + \sum_h X^{\mathrm{St}}_{u,h} \cdot C^{\mathrm{NL}}_u \quad (8b)$$
$$\mathrm{BID}_u = \sum_{b,h} P^G_{u,b,h} \cdot Q^G_{u,h} + \sum_h P^R_{u,h} \cdot Q^R_{u,h} \quad (8c)$$
$$\mathrm{REV}_u = \sum_h \left\{ \lambda^G_h \cdot \sum_b Q^G_{u,b,h} \right\} + \sum_h \lambda^R_h \cdot Q^R_{u,h}. \quad (8d)$$

For the remainder of this section and for Section IV, we will focus our attention on an arbitrary generation unit; hence, for notational simplicity, we will omit subscript u. In what follows, we justify the need for recovery payments (Subsection A), and we introduce several designs for the recovery payments (Subsection B).

A. Need for Recovery Payments

Let GPROF be the *gross profits* of an arbitrary generation unit, given by

$$\mathrm{GPROF} = \mathrm{REV} - (\mathrm{VC} + \mathrm{CC}). \quad (9)$$

From (9), it is obvious that the generation unit may incur losses, because its revenues from the commodities (energy and reserve) may not be sufficient to recover the commitment costs. Even if the commitment costs are explicitly compensated, however, the unit may still incur losses as follows. It may happen that in some hour(s) the unit is extra-marginal with respect to energy, i.e., its energy offer is above the marginal price, and yet the DAS solution schedules it at its technical minimum. Consequently, the unit's revenues will be lower than its bids. If, in addition, the unit's offers were truthful, i.e., equal to the true variable costs, then its revenues will be lower than its variable costs, and the unit will incur losses for that hour. If the total losses over all 24 hours are substantial, GPROF may end up being negative, which means that the unit will incur losses over the entire DAS horizon.

Based on this analysis, a recovery mechanism that provides adequate recovery payments is needed to compensate for the potential losses. The recovery payments should be calculated over the whole 24-hour period (as opposed to hourly recovery payments) so that any volatile behavior in the commodity prices (for small changes in the demand; see [6] for a discussion) due to the non-convex nature of the optimization problem is smoothed out. In the following subsection, we discuss several alternative recovery payment designs.

B. Recovery Payments Designs

We first consider two cases regarding the calculation of market revenue losses: cost-based and bid-based. These cases lead to two types of recovery payments:

1) cost-based recovery payments, and
2) bid-based recovery payments.

To simplify the notation, we let $\pi(a)$ and $\pi(b)$ denote the cost-based and bid-based profits of the unit, respectively. These quantities are defined as follows:

$$\pi(a) = \mathrm{REV} - (\mathrm{VC} + \mathrm{CC}) = \mathrm{GPROF} \tag{10a}$$

$$\begin{aligned}\pi(b) &= \mathrm{REV} - (\mathrm{BID} + \mathrm{CC}) \\ &= \mathrm{GPROF} - (\mathrm{BID} - \mathrm{VC}).\end{aligned} \tag{10b}$$

From (10a) and (10b), note that

$$\pi(a) = \pi(b) + (\mathrm{BID} - \mathrm{VC}) \tag{10c}$$

where the quantity $(\mathrm{BID} - \mathrm{VC})$ is the difference between the as-bid based costs and the true variable costs.

A necessary condition that must be met in order for the unit to receive recovery payments is that the above quantities are negative, i.e., that they correspond to market revenue losses. To further elaborate, let RP be the *recovery payments* of the generation unit and NPROF be its *net profits* after the recovery payments, if any. Then

$$\mathrm{NPROF} = \begin{cases} \pi(i), & \text{if } \pi(i) \geq 0, \\ \pi(i) + \mathrm{RP}, & \text{if } \pi(i) < 0, \end{cases} \quad \text{for } i = a, b. \tag{11}$$

Next, we derive expressions for the recovery payments for each of the two cases (cost-based and bid-based), assuming that the condition $\pi(i) < 0$ in (11) holds.

1) Cost-Based Recovery Payments: To be attractive, a recovery mechanism with cost-based RP should allow for positive net profits. To design such a mechanism, we must first define the basis of these profits in the case where $\pi(a) < 0$, and then derive an expression for RP that will achieve such profits. We consider two designs: one where the net profits are proportional to the unit's variable costs (design A.1) and another where the net profits are proportional to the unit's (cost-based) market revenue losses (design A.2).

Design A.1: VC-Related Profits: In this design, the final net profits, in case the unit receives recovery payments, are set to a fixed percentage, say α_1, of its variable costs, namely

$$\mathrm{NPROF(A.1)} = \alpha_1 \mathrm{VC}. \tag{12a}$$

From (10a), (11), and (12a), the recovery payments, paid ex-post, that achieve these profits are

$$\begin{aligned}\mathrm{RP(A.1)} &= \alpha_1 \mathrm{VC} - \pi(a) \\ &= (1 + \alpha_1)\mathrm{VC} + \mathrm{CC} - \mathrm{REV}.\end{aligned} \tag{12b}$$

Apart from the fact that relating the final net profits with the variable cost seems to be a rather natural approach,[1] this mechanism creates an incentive for maximizing the variable costs of a unit (in case of losses). A potential drawback of this mechanism is that the direct association of the final net profits with the variable costs, implied by (12a), could favor expensive, thus inefficient units. However, as the variable cost is also a function of the scheduled quantity, there is also an incentive for maximizing production; hence it may also lead to cost-reflective bids, so that the scheduled quantity is the maximum possible. Therefore, the outcome is not obvious and needs to be investigated.

Another key feature is that the final net profits are independent of the magnitude of the losses. This creates a "discontinuity" of the net profits at the point of zero gross profits. To elaborate, think of two units with gross profits equal to 1 euro and -1 euro, respectively. The first unit will receive no RP and will end up with net profits of 1 euro, whereas the second unit will receive RP and will end up with net profits of $\alpha_1 \cdot$ VC euro. A minimum profit condition could be applied in order to solve this discontinuity, but it could raise other discussions on the fairness of guaranteed profits, and as such it is not further examined in this work.

Design A.2: Market Revenue Loss-Related Profits: To overcome some of the drawbacks of design A.1, we propose an alternative mechanism where the final net profits that a unit is allowed to keep are set to a fixed percentage, say α_2, of its market revenue losses instead of its variable costs, namely

$$\mathrm{NPROF(A.2)} = \alpha_2[-\pi(a)] = \alpha_2(\mathrm{VC} + \mathrm{CC} - \mathrm{REV}) \tag{13a}$$

From (10a), (11), and (13a), the recovery payments that achieve these profits are

$$\begin{aligned}\mathrm{RP(A.2)} &= (1 + \alpha_2)[-\pi(a)] \\ &= (1 + \alpha_2)(\mathrm{VC} + \mathrm{CC} - \mathrm{REV}).\end{aligned} \tag{13b}$$

Such a design may prove to be a more reasonable approach, because relating net profits to losses eliminates the problem of "discontinuity" associated with design A.1, and may also result in lower recovery payments. Specifically, if $\alpha_1 = \alpha_2 = \alpha$, it is easy to see, from (12a) and (13a), that the net profits under design A.2 are lower than those under design A.1, only if $\mathrm{REV} > \mathrm{CC}$.

In addition, under this design, units that are likely to be price-makers but may possibly incur losses [perhaps because they are extra-marginal in some hour(s) or because they cannot recover their commitment costs] have an incentive to submit cost-reflective bids, as they will profit from lower energy prices (the lower their revenues, the higher their losses and hence their profits). There may still be some unfairness in the margin, in the sense that a unit with negative GPROF could incur higher NPROF than a unit with positive GPROF; however, in the long run, the probability of this event should generally be low, otherwise the unit would not be profitable in the market.

[1]Reference [12] presents a variant of design A.1 which allows explicit compensation of the commitment costs.

Note also that if $\alpha_1 = \alpha_2 = 0$, the two mechanisms are equivalent, as the unit will receive RP to end up with zero net profits. In this case, RP represents "make-whole" payments. However, the zero-net profit condition is not attractive. In practice, and as far as the units' bidding behavior is concerned, this case would produce no different incentives than as if there were no recovery payments.

To summarize, in both designs A.1 and A.2, the units may show a tendency to bid low in case they estimate market revenue losses (gross) through their market participation, to achieve higher net profits (including the recovery payments) by either maximizing their scheduled quantities (therefore their VC) in design A.1, or maximizing the magnitude of their market revenue losses in design A.2. One of the potential drawbacks of both designs A.1 and A.2 is that they may not discourage high bids, because the recovery is not directly associated with the bids; therefore, these mechanisms may result in high prices and profits. An alternative design, which associates the recovery payments with the bids is considered next.

2) Bid-Based Recovery Payments: Under a bid-based recovery mechanism, the units are compensated with RP in order to recover their costs as they are reflected by their bids. The idea of such a design is that a unit should be able to recover its as-bid costs, without resorting to a pay-as-bid scheme. In a sense, such a recovery mechanism is a "hybrid" uniform and pay-as-bid pricing scheme. We consider two alternative designs: one where the as-bid costs are always recovered, provided that the unit incurs market revenue losses (design B.1) and another where the as-bid costs are recovered, provided that the unit incurs losses *and* its price offers for the commodities are within a given "reasonable" margin from the respective true costs (design B.2).

Design B.1: Unregulated Bid Recovery: According to the unregulated bid-recovery mechanism, the recovery payments are

$$\mathrm{RP(B.1)} = -\pi(b) = \mathrm{BID} + \mathrm{CC} - \mathrm{REV}. \tag{14a}$$

From (10b), (11), and (14a), the net profits are

$$\mathrm{NPROF(B.1)} = \mathrm{BID} - \mathrm{VC}. \tag{14b}$$

From the expression above and (10c) note that the net profits are equal to the difference $\pi(a) - \pi(b)$.

This mechanism allows units that have positive bid-based profits to keep them and compensates those that exhibit market revenue losses by fully recovering their cost-reflective *bids*. This design is sketched in [11] and [12], based on the results of [5].

A drawback of this mechanism, as is shown in [11] and [12], is that, in an oligopolistic market, the units may take advantage of the bid-recovery opportunity and place very high bids, resulting in particularly high and volatile prices. Current market designs offer bid mitigation measures to protect against such a market outcome. However, these measures require constant monitoring and adjustments, as necessary.

Design B.2: Regulated Bid Recovery: To overcome the drawback of design B.1, we propose the imposition of a regulated price cap that a unit has to respect in order to be eligible for RP given by (14a). Specifically, if a unit has bid-based profits, then it will receive no RP. If the unit exhibits market revenue losses (again on a bid basis), then it will receive RP to reach NPROF, given by (14b), only if its energy (respectively, reserve) price offers lie between its true energy (respectively, reserve) cost and an upper bound, called "regulated cap", which is equal to a fixed amount, say β^G (respectively, β^R), over its true energy (respectively, reserve) cost. The regulated cap should be chosen wisely to ensure proper pricing under scarcity conditions. In other words, in order for $\mathrm{RP} > 0$, apart from the condition $\pi(b) < 0$ in (11), the following condition must also hold:

$$P^G_{u,b,h} \in \left[C^G_{u,b}, C^G_{u,b} + \beta^G\right] \quad \text{and} \quad P^R_{u,h} \in \left[C^R_{u}, C^R_{u} + \beta^R\right]. \tag{15}$$

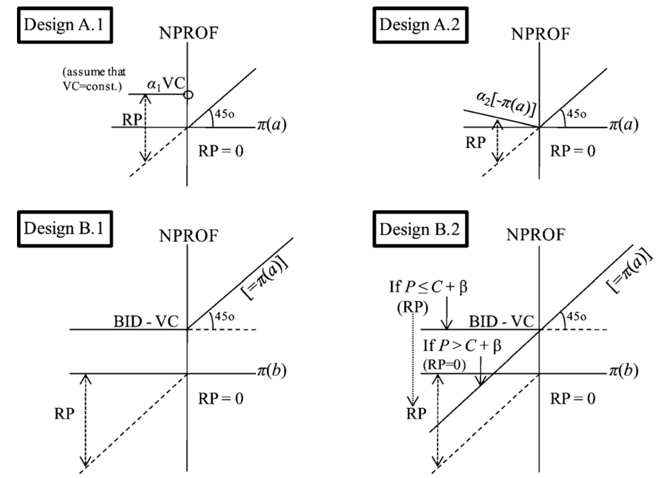

Fig. 1. Net profits for alternative mechanism designs.

This mechanism motivates the bidder to behave less speculatively. Parameters β^G and β^R can serve as design parameters set by the regulator. A large value for either of these parameters will provide a strong incentive for the unit to bid within the recovery-eligibility margin, but may also result in large total payments; a low value, on the other hand, may not provide an adequate incentive and units may tend to bid above the upper bound.

Fig. 1 summarizes the four designs and visualizes (11) to show NPROF and RP with respect to $\pi(i)$, for $i = a, b$.

IV. Recovery Mechanism Evaluation Methodology

In this section, we propose a methodology for evaluating the performance of the recovery mechanisms presented in Section III to gain further insights into their incentive compatibility properties. This methodology employs an iterative numerical procedure that solves simultaneously for the optimal bidding strategies of the profit-maximizing units.

Normally, some units, such as base-load units, are price takers, bid low or self-schedule. Others, such as peak-load OCGT units, may bid high to maximize their profits. In some cases, these units are only willing to sell ancillary services and produce energy only if the price is quite high. Therefore, the set of profit-maximizing units is a subset of U.

Let $U_p \subseteq U$ be the subset of units with a profit-maximizing strategy; the remaining units bid either at cost or at the price cap.

Let $\mathbf{P}_u$ be the vector of energy and reserve price offers, $P^G_{u,b,h}$ and $P^R_{u,h}, \forall h$, of profit-maximizing unit u. Let $\underline{\mathbf{P}}_{-u}$ be the set of vectors $\mathbf{P}_v, \forall v \in U_p \backslash \{u\}$. $\mathbf{P}_u$ represents the set of offers of unit u, and $\underline{\mathbf{P}}_{-u}$ represents the set of offers of all other units except u. Finally, let $\mathrm{NPROF}_u(\mathbf{P}_u, \underline{\mathbf{P}}_{-u})$ be the net profits after recovery of generating unit u, when its offers are $\mathbf{P}_u$ and its competitors' offers are $\underline{\mathbf{P}}_{-u}$. Each unit u will independently try to maximize its net profits, given the competitors' offers, $\underline{\mathbf{P}}_{-u}$, by setting its offers at

$$\mathbf{P}^{(*)}_u(\underline{\mathbf{P}}_{-u}) = \arg \max_{\mathbf{P}_u \in \mathbf{S}} \mathrm{NPROF}_u(\mathbf{P}_u, \underline{\mathbf{P}}_{-u}),\ u \in U_p \tag{16}$$

where $\mathbf{S}$ is the feasible space of $\mathbf{P}_u$ and is typically given by the interval $[C^G_{u,b}, P^{G,\mathrm{CAP}}]$ for energy; similarly for reserve.

If all units do the same, then, theoretically, at equilibrium, the profit-maximizing units will submit offers $\mathbf{P}^{(*)}_u$, which are the solution of the following $|U_p| \times |U_p|$ system of equations:

$$\mathbf{P}^{(*)}_u = \mathbf{P}^{(*)}_u \left(\underline{\mathbf{P}}^*_{-u}\right), \quad \forall u \in U_p. \tag{17}$$

Equation (16) represents a particularly challenging bilevel optimization problem [38], which we briefly sketch below for clarity.

At the upper level, the generation unit u aims at maximizing its net profits, as follows:

$$\max_{\mathbf{P}_u} \mathrm{NPROF}_u(\mathbf{P}_u, \underline{\mathbf{P}}_{-u}),\ \text{subject to}:\ \mathbf{P}_u \in \mathbf{S}. \tag{18}$$

At the lower level, the system operator solves the optimization problem (1)–(6), in order to minimize the total system energy cost.

The problem determined by (18) and (1)–(6) is a mixed integer nonlinear bilevel program. Note that to compute the objective function of the upper level problem, NPROF [see (11) and (10)], which depends on the recovery mechanism in effect, one needs to compute the market revenues (REV) first, which include [see (8d)] products of lower level dual (λ^G_h and λ^R_h) and primal variables ($Q^G_{u,b,h}$ and $Q^R_{u,h}$, respectively). In addition, numerical experience has shown that $\mathrm{NPROF}_u(\mathbf{P}_u, \underline{\mathbf{P}}_{-u})$ is not unimodal; therefore, maximizing it analytically is practically intractable.

If solving the optimization problem (16) is practically intractable, analytically unraveling the self-reference of (17) becomes impossible. In fact, the existence of a pure strategy Nash equilibrium solution is highly improbable, due to the complexity of the problem and the non-convexities.

Nonetheless, trying to numerically solve (17) by a classical scheme of successively approximating the optimal offer vectors $\mathbf{P}^{(*)}_u$ using a fixed-point iterative procedure, similar to the ones described in [28]–[30], is a task worth pursuing, because it can reveal patterns of bidding behavior of the individual players and the ranges and cumulative averages of values of different quantities of interest, such as the offers, recovery payments, net profits, clearing prices and total payments, among others. The outline of such a procedure follows below.

Let $\mathbf{P}^{(n)}_u$ be the value of the vector of offer-values of generating unit u at the nth iteration, and let N be the maximum number of iterations we are willing to have.

Set $\mathbf{P}^{(0)}_u$ to some initial value, $\forall u \in U_p$.
For $n = 1, 2, \ldots, N$:

$$\text{Find } \mathbf{P}^{(n)}_u = \mathbf{P}^{(*)}_u \left(\underline{\mathbf{P}}^{(n-1)}_{-u}\right), \forall u \in U_p \tag{19}$$

where $\mathbf{P}^{(*)}_u(\underline{\mathbf{P}}^{(n-1)}_{-u})$ is obtained by numerically solving (16).

A reasonable starting point would be to assume that each unit u initially submits truthful bids, i.e., $\mathbf{P}^{(0)}_u \equiv \{P^{G(0)}_{u,b,h}, P^{R(0)}_{u,h}\}$ such that $P^{G(0)}_{u,b,h} = C^G_{u,b}$ and $P^{R(0)}_{u,h} = C^R_u, \forall b, h$.

Normally, the above procedure is terminated if the maximum number of iterations, N, is reached. It may be terminated earlier at iteration $n < N$, however, if $\mathbf{P}^{(n)}_u = \mathbf{P}^{(k)}_u, \forall u \in U_p$, for some $k = 0, 1, \ldots, n-1$. In fact, if $k = n-1$, then a solution of (17) has been found. If $k < n-1$, then the procedure has reached a "cycle" of period $n-k$, meaning that the values of the next iterations will be equal to the values of previous iterations, as follows: $\mathbf{P}^{(n+1)}_u = \mathbf{P}^{(k+1)}_u, \mathbf{P}^{(n+2)}_u = \mathbf{P}^{(k+2)}_u, \ldots, \mathbf{P}^{(2n-k)}_u = \mathbf{P}^{(n)}_u$. If the space of allowable offers of the participating units is discretized, then the number of combinations of offers of the different units is finite, and therefore a cycle will always exist, as long a period as it may have. Such cycles have been observed in numerical tests and reported in [12].

The presented iterative scheme for solving what is essentially a *one-shot* (single-day) game can be viewed alternatively as a simulation procedure for solving a hypothetical, non-cooperative *repetitive* game with complete information, over many rounds, where in each round n, the decision variable for each player is the vector of energy and reserve offers, $\mathbf{P}^{(n)}_u$. In the first round, each player places some arbitrary initial offers. In the next round, each player determines his next offers by maximizing his net profits, assuming that the other players' offers will remain unchanged. This scheme generates a new set of offers. The game continues until either a predetermined number of rounds is reached, or the resulting set of offers has been reached in an earlier round. The implementation of this procedure reveals the bidding patterns of the players and the resulting market outcomes for each recovery mechanism.

The numerical procedure given by iteration (19) can be computationally extremely demanding. Even under the assumption that each unit places a single price-quantity energy offer and a single price-quantity reserve offer for each period (hour), the number of decision variables for each of the $|U_p|$ units is $2 \cdot H = 2 \cdot 24 = 48$. In this case, solving (16) means optimizing a non-convex function of 48 variables.

To overcome this computational barrier, in Part II of this paper [35], where we implement the proposed methodology, we assume that each unit places a single price-quantity energy offer (the same for all periods), and a zero-priced reserve offer that is not subject to optimization. The first assumption is not severe, as it may be the case that the units do not find it advantageous to submit multiple price-quantity offers; for example, such a behavior is sometimes observed in the Greek energy market. The second assumption helps us focus our attention on the energy bids, which determine the main volume of transactions in the day-ahead market. Note that even under zero-priced reserve offers, the reserve price can still be positive, because of marginal pricing. Both assumptions help significantly reduce the size of the problem and make it computationally tractable.

Even under the above assumptions, however, solving (16) is still not trivial. The way we practically solve it in Part II [35], is by discretization and "brute force" evaluation of all feasible solutions. Namely, we assume that the decision variable $\mathbf{P}_u$ can take a finite number of discrete values, evenly distributed a certain step size apart, over the interval from the cost of energy generation to a price cap specified by the regulator. We then evaluate the net profits for each value and select as optimal the value which maximizes these profits. The selection of the step size is important as it affects the computational time and accuracy of results. Also, in some cases, the evaluation of the net profits for certain values is redundant, which helps reduce the number of computations. Finally, the optimal offer of each generation unit can be found independently of the other units, allowing the option for massive parallel computations.

The main advantage of the proposed methodology is that it can be applied in a straightforward manner by regulators and system operators to help them predict the bidding behavior of market participants under various recovery mechanisms (ex ante evaluation). The implementation is easy, and commercial optimization platforms can be readily used. Since this is an offline procedure, the computational time is not a critical parameter.

V. Concluding Remarks

Many approaches in the literature propose pricing in day-ahead electricity markets above marginal cost as a means of recovering average variable costs, in the presence of non-convexities. In these approaches, the system operator typically sets up an optimization problem that aims at minimizing the procurement cost.

In this paper, we follow a different approach. We keep classical marginal (bid-cost) pricing by solving the day-ahead scheduling problem, whose objective is to minimize system bid-cost, and set up an additional mechanism that recovers the commitment costs and may also provide recovery payments to eliminate any market revenue losses. This approach does not directly interfere with the market design, as it provides recovery payments after the market is cleared. It interferes with it only indirectly, in that the units' bidding decisions should take into account both the revenues from the market commodities and the recovery mechanism.

We consider various recovery mechanisms and discuss their advantages and disadvantages. We also propose a comprehensive methodology for evaluating these mechanisms in terms of their performance, market power and incentive compatibility properties, as the non-convexities, inter-temporal effects, and other structural elements of the market affect the players' bidding strategies in ways which are far from obvious. In the Part II companion of this paper [35] we present the implementation of the proposed recovery mechanism evaluation methodology, associated practical details, and evaluate the recovery mechanisms in a realistic market model of the Greek energy zonal market.

This paper does not deal with recovery mechanisms required to limit or eliminate the expansion of recovery payments, intentionally sought by market participants, above and beyond the appropriate outcome of a competitive market, by manipulating the interplay between the day-ahead and real-time markets. Neither does it deal with recovery payments for lost opportunity costs, as in the case of a low-cost generator that may be scheduled to be offline even if the energy clearing price is low [6], [17], as this is a somewhat controversial issue which is outside the scope of this paper. These issues could be directions for further research.

The proposed methodology for evaluating the recovery mechanisms could be classified as a simulation approach that seeks to find equilibria without resorting to simplifying assumptions regarding the players' bidding options (e.g., Cournot bidding models), the competitors' response function (e.g., supply function competition models), or the dependence of the market price on the players' bids, (e.g., simulation models that are based on price-quota functions). It still refers to a static model, however, which neglects the fact that market participants base their decision on their accumulated experience through their interaction with the market environment (e.g., demand variations, competitors' decisions, etc.). A direction for further research would be to use adaptive agent-based simulation methodologies to reveal features of electricity markets that a static model ignores. Recent reviews of such methodologies can be found in [39]–[41].

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