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Combined cycle unit commitment in a changing electricity market scenario

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ABSTRACT

For Generation Companies (GENCOs) one of the most relevant issue is the commitment of the units, the scheduling of them over a daily (or longer) time frame, with the aim of obtaining the best profit. It strongly depends on the plant operational generation costs, which depend in turn on the choices taken at the design stage; it follows that design technical choices should also aim at determining the best generation cost structure of generating units with respect to the market opportunities. In the paper the unit commitment (UC) problem has been considered, with highlights on changes in the market scenario. The paper analyzes the relevance of some design choices (structure, size, regulation type) on the economics of the operation of gas–steam combined cycle generating units. To solve the UC problem, a recently proposed method for mixed integer nonlinear programming problems, with the use of a derivative free algorithm to solve the continuous subproblems, has been considered. The results for two GENCOs are reported: one managing a single unit and the other managing three units. Numerical examples show the sensitivity of the UC solutions to the market conditions and to the design choices on the regulation type in the evolving scenario of the Italian Electricity Market.

Introduction

The unit commitment (UC) can be referred to as the comprehensive problem of determining the on/off status and the production level of generating units over a given time horizon (a day, a week) such that some objective is optimized [1]. The UC is a mixed-integer nonlinear optimization problem.

In the past, the main attention has been devoted to centralized UC, where generators are controlled by a central authority so as to meet its load requirements. The so-called profit-based UC [2–4] calls now for the attention of generation companies (GENCOs). For them, maximizing the net revenues with an operation as profitable as possible is a pivotal issue to optimally participate into the liberalized, re-regulated markets and win competition.

Either for conversion of outdated plants or for new installations, the preferred choice is the gas–steam combined cycles technology, for its short time of return on investments, limited effects of economies of scale and convenient optimal size, high efficiency, low environmental impact, operational flexibility.

Combined cycle units may be of different size, configuration, type of regulation. Any of these technological aspects influences the overall characteristics of the unit as well as the generation cost curve. Since the UC results depend to a large extent on the operational generation costs, it is seen that technological aspects influence the UC solution; in turn, this influence depends on the market conditions the GENCO operates into.

The possibility of getting satisfactory UC solutions depends on the choices made at the design stage; a poor choice of technical characteristics could hamper a good decision-making process at the operational stage. The way technical choices do influence optimal operational results has to be given a clear evidence, and the market conditions have to be taken into account.

When looking for a UC solution, a GENCO faces uncertainty. It is so either if it acts as a price-taker (as in perfect competition) and its operational decision depends on the price forecast (e.g.the day-ahead hourly price forecast), or if it is an oligopolistic player, and its operational decision depend on its forecasted residual demand curve. To cope with the uncertainties embedded in the decision-making process, different approaches are possible, such as mean–variance, value-at-risk, conditional-value-at-risk.

In [4], the UC problem has been formulated with a modified mean–variance approach useful for both a price-taker GENCO and an oligopolistic one; the objective function accounts for the uncertainties of the problem and for the risk aversion of the decision-maker as well. In [5], the influence of the technical

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characteristics of the generating units on the UC solution has been considered for a price-taker GENCO with perfect price forecast.

The aim of this paper is to consider the general case of an oligopolistic GENCO with uncertain residual demand curve forecast and to show the influence of the technical characteristics of the combined cycles generating units on its UC solution. This would give advice on the technical solution to be chosen to ensure the best profit in a changing market scenario.

The UC problem formulation proposed in [4] is firstly recalled. A general discussion on the characteristics of gas–steam combined units is presented, with particular attention paid to the design choices on the plant cycle configuration, size and regulation type. In order to give evidence to the influence of the technical characteristics on the UC solution, we have assumed a simple representations of the combined cycle plant; in particular, we have taken into account only one of all the possible configurations a combined cycle plant can have in operation [6,7]. We made these assumptions since we judge that with different case study settings, the difference among the UC outcomes due to the design choices could be not clearly understood, and even blurred.

As case study, a comparison between two real situation in the evolving Italian Electricity Market is considered; as concern technical aspects, three different size units, configuration and regulation types are taken into account. Eventually, the results for single and multi-unit commitment problem are illustrated.

Unit commitment problem

The formulation of the unit commitment problem presented in [4] is recalled for the general case of a GENCO that can influence the market price and manages more than one generating unit; the simpler cases of a GENCO acting as a price-taker and/or managing just one unit are special cases of the general one.

Objective function

The formulation of the objective function of the UC problem, as a function to be minimized, is first presented and discussed. Technical constraints are added to obtain the complete UC problem formulation.

Costs

The operating costs a GENCO incurs in reflect the variable generation costs and the shutting-down and starting-up commitment costs.

Variable generation cost for the ith unit, C_t^i, can be described as a function of power, generated in the tth interval, P_t^i:

$$C_t^i = C^i\left(P_t^i, z_t^i\right) = a^i {P_t^i}^2 + b^i P_t^i + c^i z_t^i, \tag{1}$$

in (1), a^i, b^i, c^i are the production cost coefficients and z^i represents the set of the operating statuses of the ith unit over the commitment period ($z_t^i \in \{0,1\}$, where 0 represents inactivity whereas 1 stands for activity):

$$z^i = \left[z_1^i, z_2^i, \dots, z_T^i\right], \tag{2}$$

in which T is the number of time intervals in the time period relevant to the unit commitment problem (i.e. a day, a week). Cost C_t^i is different from zero only if $z_t^i = 1$ [see also (13)]; it accounts for the fuel costs and for the fixed share of the short-run operating costs.

When the ith unit is in operation and producing, a shut-down cost, CD_t^i, is paid each time the unit is turned off. This cost is usually considered as a constant (d^i), not dependent on the number of hours the unit has been turned on:

$$CD_t^i = CD^i(z^i, t) = \max\left\{0, d^i\left(z_{t-1}^i - z_t^i\right)\right\}; \tag{3}$$

d^i takes into account the costs of maintenance and cooling associated with the shut-down of the unit and can usually assumed negligible ($d^i = 0$).

Start-up cost, CU_t^i, is paid each time the unit is turned on; Indeed, as observed in [8], if a boiler has been shut-down and allowed to cool, its temperature will drop exponentially with time. Then, CU_t^i depends on how long the unit has been off, namely:

$$\begin{aligned} CU_t^i &= CU^i(z^i, t) = \max_{\tau=0,\dots,\tau_c^i} u_\tau^i \left(z_t^i - \sum_{k=1}^{\tau} z_{t-k}^i\right) \\ u_\tau^i &= \begin{cases} 0 & \text{if } \tau = 0, \\ \alpha^i + \beta^i\left(1 - e^{-\frac{\tau}{\gamma^i}}\right) & \text{if } \tau > 0 \end{cases} \end{aligned} \tag{4}$$

where τ_c^i, in the expression of CU_t^i, is the time the units needs to completely cool down and $\alpha^i, \beta^i, \gamma^i$ in the expression of u_τ^i, are constants that represent the cost of starting the turbine alone, the cost of starting the boiler when it is completely cooled, and the thermal time constant of the unit, respectively. A detailed description of these costs can be found in [8].

The total operating cost incurred by the GENCO over the commitment period, C_{tot}, is:

$$C_{tot} = C_{tot}(z, P) = \sum_{i=1}^{N_u} \sum_{t=1}^{T} C^i\left(P_t^i, z_t^i\right) + CD^i(z^i, t) + CU^i(z^i, t), \tag{5}$$

where N_u represents the number of generating units to be committed; z and P the commitment of all units over the programming period and their production, respectively [see also (2)]:

$$\begin{aligned} z &= [z^1, \dots, z^{N_u}] \\ P &= [P^1, \dots, P^{N_u}] \\ P^i &= \left[P_1^i, P_2^i, \dots, P_T^i\right]. \end{aligned} \tag{6}$$

We remark that no linearization of CD_t^i and CU_t^i is carried out to obtain expression (5) of the total cost C_{tot}. In fact, even if such a linearization had been performed, the overall objective function would still turn out to be nonlinear and non-convex (as it will be clarified in the next subsection).

Revenues

The GENCO's revenue in the tth interval, R_t, derives from selling the power generated in the interval to the electricity market. Recalling [4], the selling price is modeled by using the GENCO's residual demand function, $\rho(\cdot)$, which depends on the total power produced (sold) by the GENCO in the interval, and may vary along the commitment period. Since the residual demand function derives from the forecast of load demand and competitors' behavior, it is affected by uncertainty.

With this understanding, the GENCO's revenues in the tth time interval can be modeled as:

$$R_t = R_t(\rho_t, P_t) = \rho(P_t, \theta_t, t) P_t, \tag{7}$$

where θ_t represents a random variable and P_t is the total power produced (sold) by the GENCO in the tth interval

$$P_t = \sum_{i=1}^{N_u} P_t^i. \tag{8}$$

Total revenues over the commitment period, R_{tot}, are given by:

$$R_{tot} = R_{tot}(P_G, \theta) = \sum_{t=1}^{T} \rho(P_t, \theta_t, t) P_t, \tag{9}$$

where P_G and θ represent the GENCO's total production and the uncertainties on the residual demand forecast for all time intervals, respectively:

$$P_G = [P_1, \ldots, P_T]$$
$$\theta = [\theta_1, \ldots, \theta_T]. \tag{10}$$

Profit

The GENCO's profit over the commitment period, Π_{tot}, depends: (a) on the commitment of the units, i.e., z); (b) on the powers generated by each unit, i.e., P; (c) on the GENCO's total production, i.e., P_G; (d) on the vector of random variables θ that are used to capture the uncertainty in the residual demand curves. Hence, we can write:

$$\Pi_{tot} = R_{tot}(P_G, \theta) - C_{tot}(z, P) = \Pi_{tot}(z, P, P_G, \theta). \tag{11}$$

Note that, even though R_{tot}, and hence Π_{tot}, depends on a vector of random variables θ, we can obtain a deterministic objective function by adopting a modified mean–variance approach as better clarified in the following subsection.

Objective function

In addition to the profit, the objective function to be minimized can account for the risk in committing, as in [4,9]:

$$f(z, P, P_G) = B_r(z, P)\sigma^2_\theta(\Pi_{tot}(z, P, P_G, \theta)) - E_\theta(\Pi_{tot}(z, P, P_G, \theta)) \tag{12}$$

where $E_\theta(\Pi_{tot})$ and $\sigma^2_\theta(\Pi_{tot})$ are, respectively, expected value and variance of the profit with respect to the vector of random variables θ, and $B_r(z, P)$ is a function of the commitment, i.e. of the z and P variables, and is defined as follows

$$B_r(z, P) = \frac{A_r}{2C_{tot}(z, P)}.$$

We note that, due to the weighting function $B_r(z, P)$, the objective function f turns out to be non-convex. This is a drawback of the adopted and modified mean–variance formulation; the weighting function $B_r(z, P)$ would yield a non-convex objective function even if the underlying cost function was convex. We remark that there are other ways in which it is possible to account for the risk in committing the units apart from the mean–variance approach. In particular, possible ways could consists in incorporating Value-at-Risk (VaR) or Conditional Value-at-Risk (CVaR) [10] in the objective function in place of the variance/covariance terms.

In the expression of $B_r(z, P)$, constant A_r is the so-called risk aversion coefficient [4,9], which allows to account for the risk attitude of the decision-maker.

Scenarios

We recall the scenarios definition proposed in [4]. Namely, in the function $\rho(P_t; \theta_t; t)$ representing the residual demand curve, we assume all the random variables $\theta_t, t \in \mathcal{T}$, have the same discrete probability distribution; θ_t has $r = 21$ different possible realizations $\theta^1_t, \ldots, \theta^r_t$ with probabilities $\pi^1, \ldots, \pi^r$.

The realizations of prices and quantities in each scenario can be represented as follows, for $s = 1, \ldots, r$:

$$\rho(p_t; \theta^s_t; t) = \rho(p_t - \Delta p(\theta^s_t); t) + \Delta\rho(\theta^s_t),$$

where $\Delta p(\theta^s_t)$ and $\Delta\rho(\theta^s_t)$ are variations of quantity and price. We examined two cases of price variations, as reported in Table 1. The first case, referred to as "Small Price Variations" (SPV) is represented by $\Delta\rho_1(\theta_t)$ and corresponds to a knowledge of prices less uncertain that the one represented by $\Delta\rho_2(\theta_t)$, referred to as "Large Price Variations" (LPV). Finally, scenarios' probability distribution is reported in Fig. 1.

Table 1
Scenario realizations.

θ_t	$Pr(\theta_t)$	$\Delta p(\theta_t)$	$\Delta\rho_1(\theta_t)$ (SPV)	$\Delta\rho_2(\theta_t)$ (LPV)
θ^1_t	0.000429117	−100	10	50
θ^2_t	0.000920851	−70	9	45
θ^3_t	0.002480458	−50	8	40
θ^4_t	0.005984882	−35	7	35
θ^5_t	0.012934755	−30	6	30
θ^6_t	0.025040268	−25	5	25
θ^7_t	0.043420952	−20	4	20
θ^8_t	0.067443978	−15	3	15
θ^9_t	0.093837208	−10	2	10
θ^{10}_t	0.116948937	−5	1	5
θ^{11}_t	0.130558596	0	0	0
θ^{12}_t	0.130558596	5	−1	−5
θ^{13}_t	0.116948937	10	−2	−10
θ^{14}_t	0.093837208	15	−3	−15
θ^{15}_t	0.067443978	20	−4	−20
θ^{16}_t	0.043420952	25	−5	−25
θ^{17}_t	0.025040268	30	−6	−30
θ^{18}_t	0.012934755	35	−7	−35
θ^{19}_t	0.005984882	50	−8	−40
θ^{20}_t	0.002480458	70	−9	−45
θ^{21}_t	0.001349967	100	−10	−50

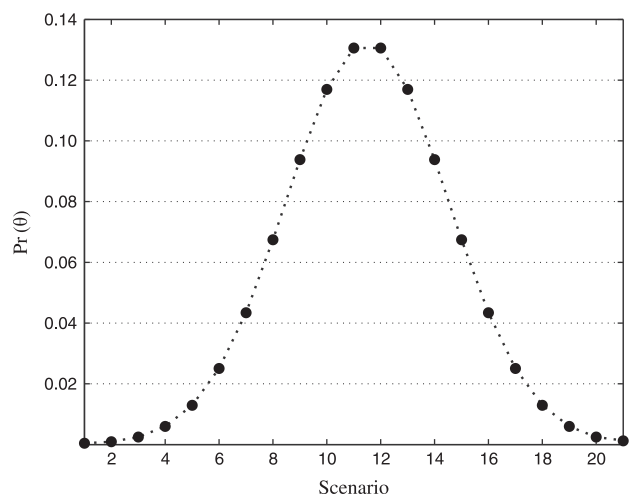

Fig. 1. Scenarios' probability distribution.

Constraints

Technical constraints of units do not interfere with each other; generating units are assumed to behave independently from one another.

For each unit, the following constraints hold, where the operating condition at the beginning of the commitment time period is represented by:

z^i_0: initial operating status,
P^i_0: initial generated power.
$\widehat{y}^i_0, (\widetilde{y}^i_0)$: number of consecutive time intervals in which the unit has been uncommitted (committed) at the beginning of the commitment period. More precisely, if $z^i_0 = 1$ then $\widetilde{y}^i_0 > 0$ and $\widehat{y}^i_0 = 0$, whereas, if $z^i_0 = 0$ then $\widetilde{y}^i_0 = 0$ and $\widehat{y}^i_0 > 0$.

Production

$$P^i_m z^i_t \leqslant P^i_t \leqslant P^i_M z^i_t, \quad t = 1,\ldots,T \tag{13}$$

where P^i_m and P^i_M are minimum and maximum production of the unit.

Rate of change

$$\begin{aligned} &P^i_{t+1} - P^i_t \leqslant R^i_{up}, \quad t = 1,\ldots,T-1 \\ &P^i_{t+1} - P^i_t \geqslant -R^i_{dw}, \quad t = 1,\ldots,T-1 \end{aligned} \tag{14}$$

where R^i_{up} and R^i_{dw} are maximum ramp-up and ramp-down rates of the unit.

Up and down times

$$\begin{aligned} &z^i_t - z^i_{t-1} \leqslant z^i_\tau, \begin{cases} \tau = t+1,\ldots,\min\left\{t + t^i_{up} - 1, T\right\}, \\ t = 1,\ldots,T \end{cases} \\ &z^i_{t-1} - z^i_t \leqslant 1 - z^i_\tau, \begin{cases} \tau = t+1,\ldots,\min\{t + t^i_{dw} - 1, T\}, \\ t = 1,\ldots,T \end{cases} \end{aligned} \tag{15}$$

where t^i_{up} and t^i_{dw} are the minimum on and off durations.

The value of $\widetilde{y}^i_0$ and $\widetilde{y}^i_0$ are specifically accounted for.

UC problem

Finally, we can state the UC problem as:

$$\begin{aligned} \min \quad & f(z, P, P_G), \\ \text{s.t.} \quad & g(P, P_G) = 0, \\ & h(z, P) \geqslant 0, \end{aligned} \tag{16}$$

where $f(z, P, P_G)$ is given by (12), $g(P, P_G)$ represents (8), and $h(z, P)$ represents (13)–(15).

Problem (16) is a deterministic problem, where the uncertainties are embedded in the preprocessed mean–variance objective function; it is a mixed integer nonlinear programming problem.

Solution method

Let us better examine problem (16). First, note that when the discrete activation/deactivation variables z are held fixed, say $z = \bar{z}$ with $\bar{z}$ satisfying (15), Problem (16) becomes a standard linearly constrained optimization problem, which can be put in the form

$$\begin{aligned} \min \quad & \phi(P, P_G) = f(\bar{z}, P, P_G), \\ \text{s.t.} \quad & g(P, P_G) = 0, \\ & h(\bar{z}, P) \geqslant 0. \end{aligned} \tag{17}$$

The main feature of both problems (16) and (17) resides in their objective functions which, in the cases of interest (as those considered in Section 'Combined cycle unit commitment solutions'), are non-convex and nonsmooth functions. Indeed, we recall the $f(\cdot)$ is highly nonlinear and non-convex due to the presence of the weighting function $B_r(z, P)$, see (12).

In [11] an algorithm has been introduced for solving mixed variable programming problems, just like problem (16) above, based on the combination of a local search with respect to the continuous variables and of a local search in the discrete neighborhood of the current point. This algorithm has been applied to the solution of Problem (16). In particular, the method is based on the idea to alternate between two phases:

- an attempt to update the continuous variables, P and P_G, by a local continuous search (Phase 1),
- an attempt to update the discrete variables, z, by a local search in the discrete neighborhood of the current point (Phase 2).

Some comments are in order to better understand the behavior of the second phase, i.e. that in charge of updating the discrete variables. In this phase we try to update the discrete variables by considering the points belonging to the discrete neighborhood $\mathcal{N}(z, P, P_G)$ of the current incumbent point produced by Phase 1. We recall that given any feasible point (z, P, P_G), a discrete neighborhood is a user-defined set of feasible points (z', P', P'_G) "close" to the given one. For a better understanding of the concept and for the rigorous definition of discrete neighborhood adopted in the paper we refer the reader to [4].

The proposed algorithm for mixed variable programming is formally stated as follows:

Mixed Integer Variable Algorithm (MIVA).

Data: A feasible production schedule $(\bar{z}, \bar{P}, \bar{P}_G, \xi \geqslant 0$, $\theta \in (0, 1), \bar{\eta} > 0$.

Repeat

(S1) Compute $(\widetilde{P}, \widetilde{P}_G)$ s.t. $U(\bar{z}, \widetilde{P}, \widetilde{P}_G) \leqslant U(\bar{z}, \bar{P}, \bar{P}_G)$ by means of a continuous local search.

(S2) If there exists a $(\hat{z}, \widehat{P}, \widehat{P}_G) \in \mathcal{N}(\bar{z}, \widetilde{P}, \widetilde{P}_G)$ such that

$$U(\hat{z}, \widehat{P}, \widehat{P}_G) \leqslant U(\bar{z}, \widetilde{P}, \widetilde{P}_G) - \bar{\eta},$$

set $\bar{z} := \hat{z}, \bar{P} := \widehat{P}, \bar{P}_G := \widehat{P}_G$, and go to S5.

(S3) Define $W := \{(z, P, P_G) \in \mathcal{N}(\bar{z}, \widetilde{P}, \widetilde{P}_G) : U(z, P, P_G) \leqslant U(\bar{z}, \widetilde{P}, \widetilde{P}_G) + \xi\}$.

- **(3.1)** If $W \neq \emptyset$, choose $(z', P', P'_G) \in W$. Otherwise go to S4.
- **(3.2)** Compute P'' and P''_G by applying a continuous local search to Problem (16) where $z = z'$ is fixed.
- **(3.3)** If $U(z', P'', P''_G) \leqslant U(\bar{z}, \widetilde{P}, \widetilde{P}_G) - \bar{\eta}$, set $\bar{P} := P''$, $\bar{P}_G := P''_G, \bar{z} := z'$, and go to S5.
- **(3.4)** set $W := W \setminus \{(z', P', P'_G)\}$, and go to 3.1.

(S4) Set $\bar{P} := \widetilde{P}, \bar{P}_G := \widetilde{P}_G$.
if neither the local continuous search nor the discrete search have been able to produce a decrease of the objective function greater or equal to $\bar{\eta}$, set $\bar{\eta} := \theta\bar{\eta}$.

Until (S5) Stopping condition is met.

At Step S1, Phase 1 is performed by applying the local continuous search starting from point $(\bar{P}, \bar{P}_G)$. This procedure tries to produce a new point $(\widetilde{P}, \widetilde{P}_G)$, where the objective function is sufficiently decreased. In particular, if the procedure is not able to produce a sufficient decrease of the objective function, the point $(\widetilde{P}, \widetilde{P}_G)$ is set equal to $(\bar{P}, \bar{P}_G)$.

Phase 2 is performed in Steps S2 and S3. In particular, at Step S2 the objective function is evaluated at each point in $\mathcal{N}(\bar{z}, \widetilde{P}, \widetilde{P}_G)$. If one of these points produces a decrease with respect to $U(\bar{z}, \widetilde{P}, \widetilde{P}_G)$ greater than or equal to $\bar{\eta}$, it becomes the current point and a new iteration is started. Otherwise the discrete neighborhood is further investigated in Step S3. In particular, a set $W \subseteq \mathcal{N}(\bar{z}, \widetilde{P}, \widetilde{P}_G)$ of points with objective value not significantly

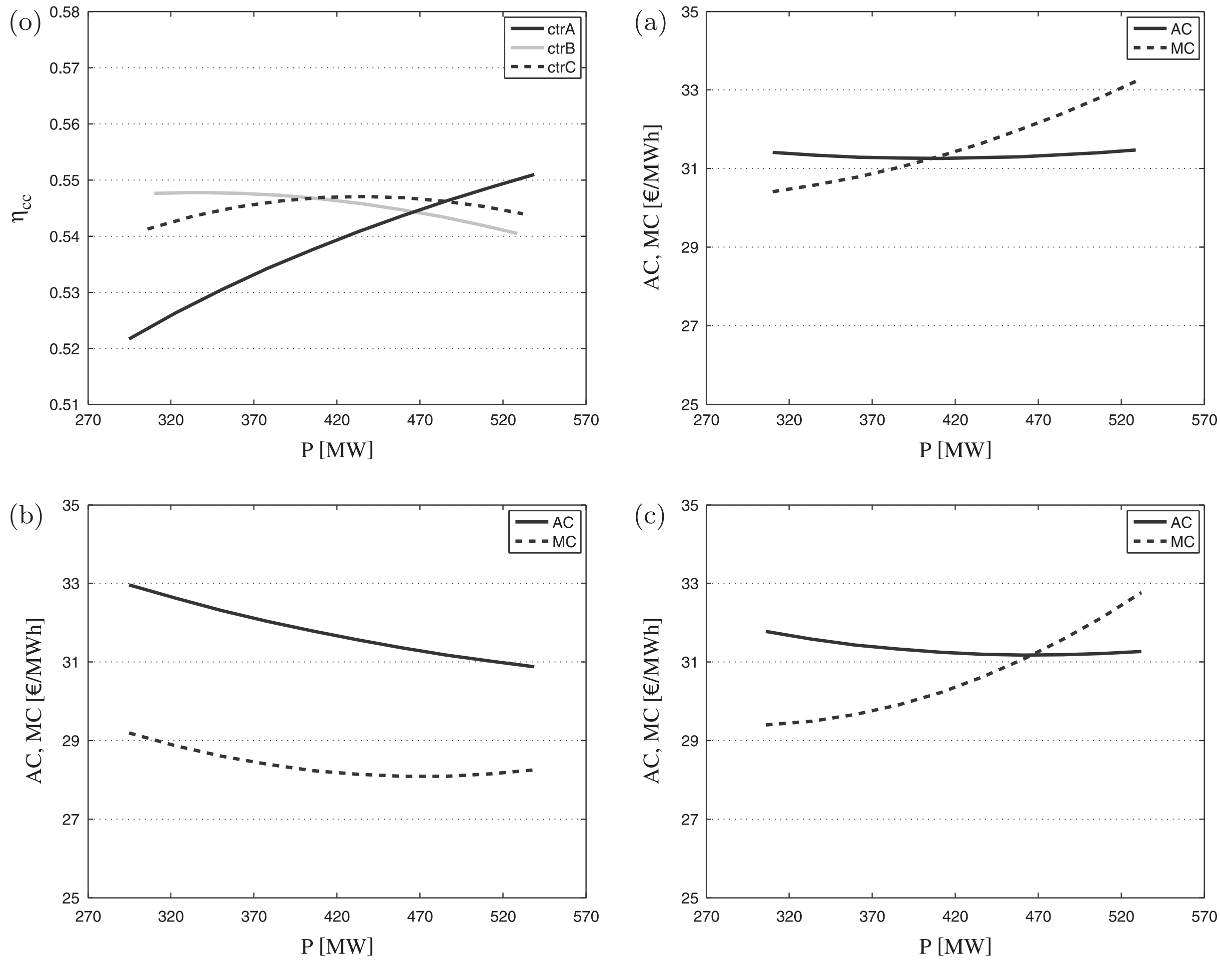

Fig. 2. (o) Combined cycle global efficiency (η_{cc}), versus total output power for a large size power plant (3LR) with type A, B and C regulation. (a,b,c) Average variable costs (AC) and marginal costs (MC) versus total output power for a large size combined cycle power plant (3LR) with: (a) type A regulation, (b) type B regulation, (c) type C regulation.

worse than $U(\bar{z}, \widetilde{P}, \widetilde{P}_G)$ is selected. Each of these points $(z', P', P'_G) \in W$ is considered "promising", and the algorithm tries to determine if it is worth replacing $\bar{z}$ with z'.

At Step S4 the point $(\bar{z}, \widetilde{P}, \widetilde{P}_G)$ becomes the new current point and, if neither the local continuous search nor the discrete search have been able to produce a decrease of the objective function greater or equal to $\bar{\eta}$, then this parameter is reduced before starting the next iteration.

Algorithm MIVA stops when $\bar{\eta}$ becomes sufficiently small, say $\bar{\eta} \leqslant 10^{-5}$ and neither the local continuous search nor the discrete search have been able to produce a decrease of the objective function greater or equal to $\bar{\eta}$.

We stress that Algorithm MIVA is a local-search-type method, that is it is able to solve problem (16) to local optimality. To try and achieve better results, MIVA can be inserted in a multi-start scheme. A detailed test of MIVA in comparison with other classical approaches was reported in [4]; in it, a better accuracy with less computational times was always observed. In all cases, on a Intel Pentium IV 3.2 GHz processor with 2 GB memory, simulation times were always within 4 h of CPU time.

Combined cycle power plants

Combined cycle power plants present a wide range of design options, such as the number of units, the type of Heat Recovery Steam Generator (HRSG), the regulations, the electrical circuits.

Such characteristic do influence the operating costs of the plant; in particular, the dependence of the operational costs on the size, the configuration and the regulation type of the units has been addressed in [5]. Here, we recall the main results, useful to the subsequent development of the application.

Configuration and size

Combined cycle power plant can be equipped with a HRSG with two levels of evaporation pressure (2L) or with three levels of evaporation pressure with reheat (3LR); the latter shows better thermal recovery and higher efficiency than the former.

The operating conditions of the steam cycle strictly depend on the ones of the gas cycle (we refer here to the unfired technology); a detailed modeling of the HRSG allows to account for that dependence. In addition, it is relevant to take into account the actual environmental conditions, such as the ambient air pressure and temperature, and the cooling water temperature.

A combined cycle unit can be equipped with different numbers of turbines; typical configurations are *one gas-one steam* and *two gas-one steam*.

Regulation

Combined cycle units are mainly controlled by acting on the gas section. It can be carried out basically by:

a. acting only on the fuel mass flow (to vary the gas turbine output power);
b. acting on both the fuel mass flow and the compressor inlet guide vanes (to vary both the gas turbine output power and one of the characteristic temperatures of gas cycle).

The general and most common situation is b.; it allows for different control laws:

A. to keep at constant reference value, T_{co}, the gas temperature at the combustor outlet;
B. to keep at constant reference value, T_{to}, the gas temperature at the gas turbine outlet;
C. to force the exhaust gas temperature at the gas turbine outlet to assume a reference value, $T_{to,ref}$, which varies according to the operating conditions.

For example, a linear law could be

$$T_{to,ref} = T_{to,rated}\left(1 - \alpha_s \frac{P_{GT} - P_{GT,rated}}{P_{GT,rated}}\right), \tag{18}$$

where P_{GT} represents gas turbine output power, $\alpha_s > 0$ the slope factor, and subscript 'rated' indicates the vale at rated operating conditions.

The choice of the type of regulation, which is carried out at the design stage, influences the operation of the plant. Indeed, for given gas cycle components, it determines different exhaust gas characteristics, and then a different design of HRSG and of the steam section to maximize the exhaust gas heat recovery. The effects of different types of regulation on the cost curves are represented for a large 3LR combined cycle power plant in Fig. 2 [5].

Combined cycle unit commitment solutions

The dependency of the UC solution on the decision taken at the design stage in different market scenario settings is shown.

Table 2
Unit data.

Regulation type	Year	Cost coefficients		
		a [€/MW^2 h]	b [€/MW h]	c [€/h]
Unit #1 – 56 MW, 2L – one gas turbine & one steam turbine				
A	2008	0.14366	40.196	320.1
	2012	0.13361	37.381	297.7
B	2008	−0.01756	50.133	214.2
	2012	−0.01633	46.623	199.2
C	2008	0.06436	45.162	255.9
	2012	0.05985	42.000	237.9
	P_{min} [MW]	P_{max} [MW]	R_{up} [MW/h]	R_{dw} [MW/h]
A	32.24	56.09	33.00	33.00
B	30.80	57.29	33.00	33.00
C	31.61	56.79	33.00	33.00
	Min time on t_{up} [h]	Min time off t_{dw} [h]	Shut-down cost d [€]	Start-up cost α [€] ($\beta = 0$)
	3	2	0	493
Unit #2 – 530 MW, 2L – two gas turbines & one steam turbine				
A	2008	0.0062015	53.7537	1248.3
	2012	0.0057673	49.9905	1160.9
B	2008	−0.0035971	56.3631	2079.3
	2012	−0.0033453	52.4172	1933.7
C	2008	0.0111244	48.3483	2553.7
	2012	0.0103456	44.9636	2375.0
	P_{min} [MW]	P_{max} [MW]	R_{up} [MW/h]	R_{dw} [MW/h]
A	307.5	528.1	308.0	308.0
B	293.8	538.2	295.0	295.0
C	305.0	531.1	306.0	306.0
	Min time on t_{up} [h]	Min time off t_{dw} [h]	Shut-down cost d [€]	Start-up cost α [€] ($\beta = 0$)
	4	3	0	6571
Unit #3 – 530 MW, 3LR – two gas turbines & one steam turbine				
A	2008	0.0121158	49.2659	1929.7
	2012	0.0112676	45.8169	1794.6
B	2008	−0.0038304	56.5874	1983.2
	2012	−0.0035622	52.6259	1844.4
C	2008	0.0139996	45.8104	3018.4
	2012	0.0130196	42.6033	2807.1
	P_{min} [MW]	P_{max} [MW]	R_{up} [MW/h]	R_{dw} [MW/h]
A	310.0	528.8	312.0	312.0
B	294.7	539.0	295.0	295.0
C	305.9	532.2	306.0	306.0
	Min time on t_{up} [h]	Min time off t_{dw} [h]	Shut-down cost d [€]	Start-up cost α [€] ($\beta = 0$)
	4	3	0	6571

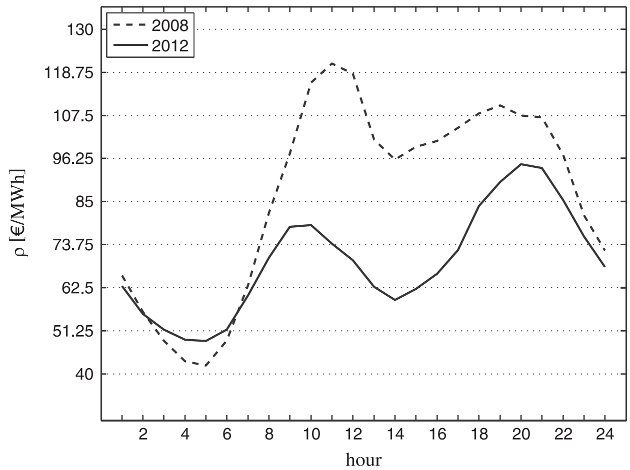

Fig. 3. Daily diagram of average hourly prices of the Wednesdays of the year.

Three possible units of different configuration (with respect to the HRSG and number of turbines), and size are considered, as well as the three possible regulation schemes presented in Section 'Solution method'. For all cases the generating units are assumed initially turned on and able to shut down. The main data for such units are reported in Table 2; more details can be found in [5].

Two market situations have been taken into account, which represent the evolving Italian Market in the years 2008 and 2012. The daily diagrams of Fig. 3 have been considered as market prices for both situations; each diagram is obtained assuming an average hourly price computed on all the Wednesdays of the year. For each market scenario, two possible GENCOs, with different shapes of the residual demand curve are considered. The first one, named *singleunit-GENCO*, represents a small market operator with little or no market power; the second one, *multiunit-GENCO*, a large market operator whose decisions may heavily affect the market price. Piece-wise linear functions have been defined for the residual demand curves $\rho(\cdot)$, whose parameters have been obtained by elaborating freely distributed historical data from the Italian Gestore del Mercato Elettrico (the independent market operator) [12,4].

The piece-wise linear residual demand curves directly concur in the expression of the objective function $f(z, P, P_G)$, i.e. no further modeling with addition binary variables has been carried out. This is reasonable since the nonlinearity and non-convexity of the objective function does not depend only on the nonlinearity of the residual demand curves but, rather on the expression of the weighting function $B_r(z, P)$, see e.g. (12).

Three different *singleunit-GENCO*s are considered here operating different types of unit: respectively type #1, #2 and #3 of Table 2. As concern the only *multiunit-GENCO*, it operates three units, one for each type.

Regarding risk aversion A_r, a slightly more competitive behavior of *singleunit-GENCO* ($A_r = 4$) with respect to the *multiunit-* one ($A_r = 3$) has been considered (see Eq. (12), [4,9]).

Tables 3 and 4 show the results for all cases, for both year 2008 and 2012, making possible some considerations on the evolution of the market and the related optimal choices regarding the technical aspects of the units.

Singleunit-GENCO

As concerns *singleunit-GENCO*s (see Table 3), a comparison of results for all sizes in year 2008 highlights that the highest profit is obtained for a *type-B* regulation. This regulation aims to minimize unit costs at full power (see Fig. 2(b)); it means that, in the case studies, the market pushes units to operate at high power, making it convenient to adopt a regulation type in which the maximum global efficiency is at full load (see Fig. 2(o)). So, no particular flexibility is required to regulation; this is also a characteristic of the units in oligopolistic markets [5]. Eventually the results show also that size of units has no relevant impact on the choice of regulation, whereas small units present a higher profit for MW than the largest ones.

The results for *singleunit-GENCO* in year 2012 show a noticeable different situation, also highlights how market changes towards a

Table 3
Profit, *singleunit-GENCO*.

Unit type	Regulation type	Year	Profit
#1	A	2008	50060.2
		2012	30005.2[b]
	B	2008	52239.1[a]
		2012	29056.8
	C	2008	51327.2
		2012	29734.3
#2	A	2008	416771.9
		2012	251245.3[b]
	B	2008	433608.5[a]
		2012	235982.1
	C	2008	421935.2
		2012	249216.5
#3	A	2008	418227.8
		2012	255391.5[b]
	B	2008	435164.8[a]
		2012	237479.9
	C	2008	424096.7
		2012	251105.5

[a] Best in 2008.
[b] Best in 2012.

Table 4
Profit, *multiunit-GENCO*.

Unit type	Regulation type	Year	Profit
#1 #2 #3	A A A	2008	736940.7
		2012	392187.5
	A B C	2008	744314.1
		2012	398684.6
	A C B	2008	740168.9
		2012	398263.2
	A B B	2008	748827.61
		2012	397147.2
	A C C	2008	734989.1
		2012	395733.3
	B B B	2008	747439.8
		2012	398430.4
	B A C	2008	729669.8
		2012	395180.9
	B C A	2008	729520.2
		2012	395921.0
	B A A	2008	725358.8
		2012	393576.8
	B C C	2008	733489.4
		2012	397128.4
	C C C	2008	732838.4
		2012	396553.1
	C B A	2008	750104.0[a]
		2012	399062.9[b]
	C A B	2008	736456.6
		2012	397775.9
	C B B	2008	746765.1
		2012	397828.9
	C A A	2008	724705.1
		2012	393010.7

[a] Best in 2008.
[b] Best in 2012.

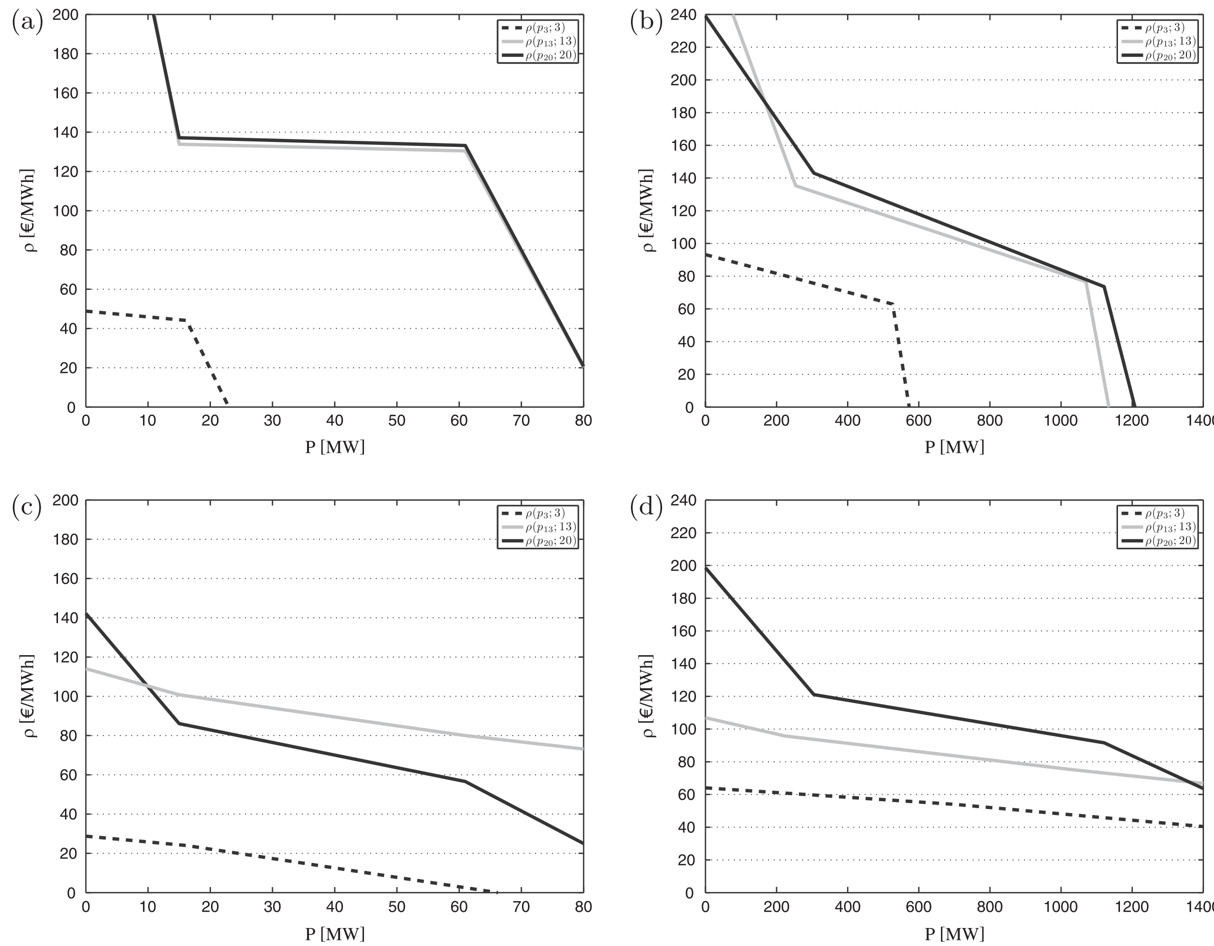

Fig. 4. (a) Residual demand curves for a *singleunit-GENCO* at $t = 3, 13, 20$, for unit #1, in 2008 – (c), same case in 2012. (b) Residual demand curves for a *multiunit-GENCO* at $t = 3, 13, 20$, for units #1#2#3, in 2008 – (d), same case in 2012.

more competitive one. In this case, a comparison among results for all sizes of the units highlights that the best profit is obtained for a *type-A* regulation. This regulation aims to maximize gas heat recovery efficiency at minimum power operation (see Fig. 2b), so as to ensure that the combined cycle global efficiency is kept almost constant for varying the output power (see Fig. 2o). In other words,a great flexibility is required to regulation to make the unit able to operate at low cost in a high range of output powers. This is also a characteristic required to units in a competitive market [5]. Also in this case, the size of the units has no relevant impact on the choice of regulation and small units present a higher profit per MW than large ones.

Comparing different cases both for year 2008 and 2012, it can be also noticed a significant reduction of profit, due to low electricity prices in 2012. The changing situation of the market towards a more competitive one is also evidenced by a comparison between the two residual demand curves of *singleunit-GENCO*, obtained from the historical data of the market. In the residual demand curve for 2008, the middle segment is almost horizontal (see Fig. 4(a) and 4(c)), reporting the typical behavior of a price taker; in 2012, the middle segment presents a more pronounced slope, showing an increased market power of *singleunit-GENCO*. The comparison makes it clear that for a *singleunit-GENCO* the change in the market structure also would require different types of regulation. The generated power and daily profit for the best solutions are reported in Fig. 5.

Multiunit-GENCO

Differently from *singleunit-GENCO* (see Table 4), the *multiunit-GENCO* has the possibility to influence the price of the market, thanks to its market power. It can be noticed that if the same regulation is adopted for all units, the best profit is obtained, both for 2008 and 2012, for a *type-B* regulation. This means that, in both cases, a *multiunit-GENCO*, in influencing the market price, operates close to full power to maximize its profit. However it can be also noticed that even a better profit can be obtained with a mix of regulations of type CBA, both for year 2008 and 2012. This indicates that even for a *multiunit-GENCO*, the presence of a proper combination of regulation types that ensures a greater flexibility allows a more effective use of units to find the best solution.

As for *singleunit-GENCO*, a comparison between results for year 2008 and 2012 for *multiunit-GENCO* shows a significant reduction of the profit, as expected from a more competitive market situation. The comparison among demand curves in 2008 and 2012 for *multiunit-GENCO* (see Fig. 4(b) and 4(d)) gives also a measure of the lost market power, highlighted by the less pronounced slope of the middle segment. The generated power and daily profit for the best solutions are reported in Fig. 5.

Eventually, a comparison among demand curves for *singleunit* and *multiunit-GENCO* in 2012, with the presence of a still significant slope in both cases, highlights that in the transition toward a more competitive market situation in Italy, the number of market

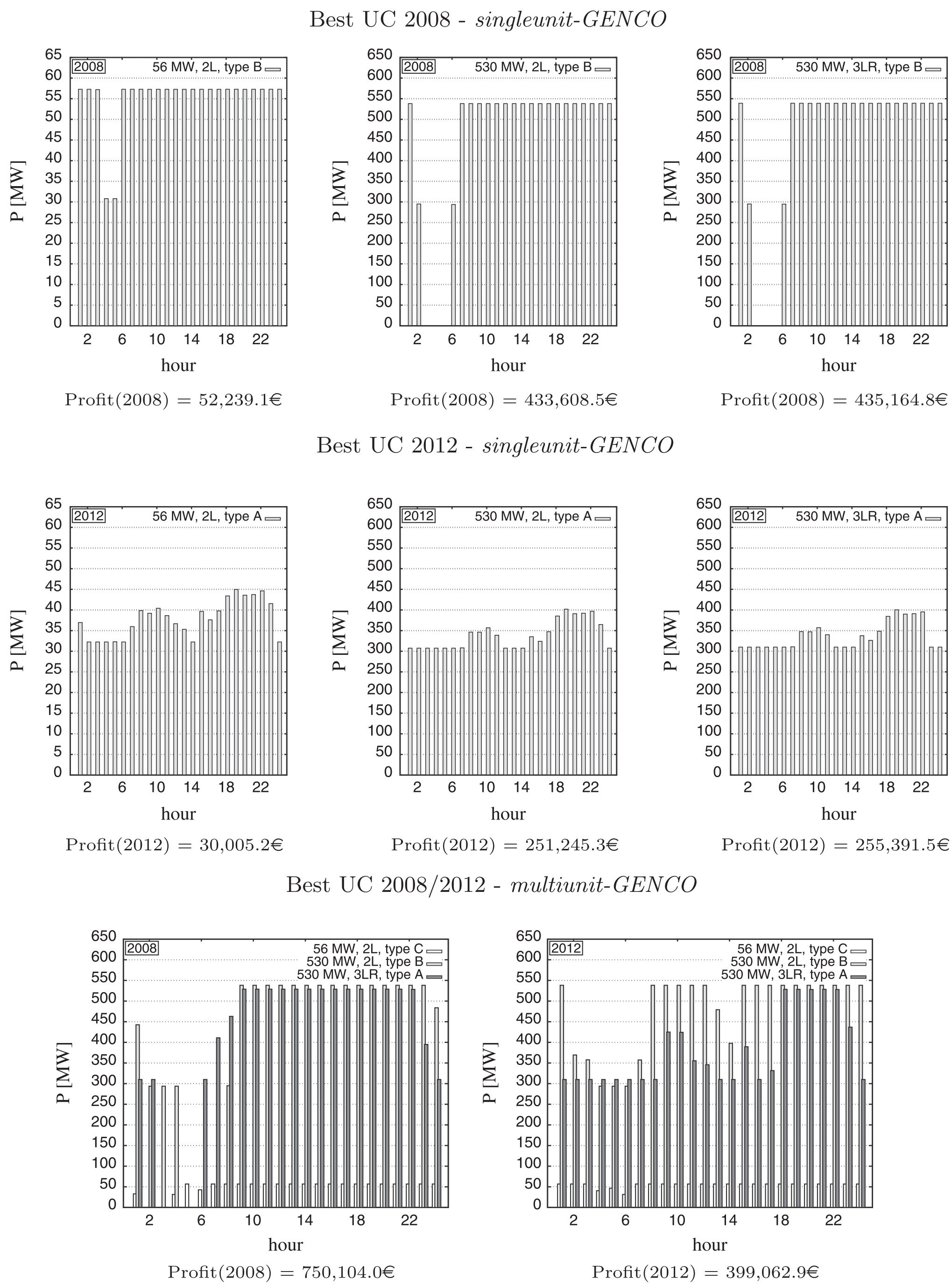

Fig. 5. Best UC results: generated power and daily profit.

operators is not yet sufficient to consider a perfect market situation, even if market is much more competitive than in 2008.

Conclusion

The change in the electricity market requires producers to get the best from their units. To achieve this result, the design decision-making process needs to be supported in choosing the best cost structure with respect to the market opportunities. The paper highlights the economical influence of some technical choices on the generation costs, and the consequent impact on the UC solution for *single-* and *multiunit-GENCO*. Numerical results have shown the economical relevance at the operation stage of technical choices taken at the design stage, such as unit structure, size and regulation type in the evolving scenario of Italian Electricity Market.

Acknowledgements

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