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STRATEGIC BIDDING IN DEREGULATED POWER SYSTEMS

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ABSTRACT

This paper describes a general methodology for bidding in a deregulated generation market. It is discussed the hierarchy of the problems that must be solved and it is presented in detail a method for solving the utility self unit-commitment problem in deregulated systems. Cost recovery is one of the main utility priorities. The method proposed in this paper considers both the expected energy sales revenue and expected operating cost to determine optimum generation bids. Finally, results of an application example are presented.

Keywords: Strategic bidding, Deregulation, Unit-commitment.

1. INTRODUCTION

The electricity supply industry is undergoing a major restructuring process. Traditional and centralised regulation is being replaced by a competitive and deregulated framework. Utilities need new planning and market tools to operate in a new competitive environment. This is the case for Spanish utilities since January 1st, 1998. They must operate their generating units according to the results of the electricity wholesale market.

Several methods have been proposed for simulating competitive generation markets [1]. Simulation models are focused on characterising generator behaviour, price evolution, market power influences, etc. However, in general, short-term constraints and inter-temporal links are not considered, so these models do not solve the optimal bidding problem. Reference [2] reviews relevant literature about strategic bidding. References [3,4] solve the optimal transactions scheduling problem between participants in deregulated markets. Reference [3] models price uncertainty using fuzzy numbers. In reference [4] dynamic programming is used to solve a 24 hours horizon economic dispatch, where profit is maximised subject to minimum up/down time and ramp constraints. However, in all these references unit-commitment constraints are not considered and it is assumed a perfect competition scenario where price corresponds always to the marginal cost of generators.

The research work presented in this paper shows the problems to be solved by a generating utility and describes in detail the self unit-commitment problem in a competitive market. In this approach, competitor behaviour is deterministically characterised by their forecasted bidding curves. Mixed-integer linear programming is used to formulate the 0/1 variables, i.e. start-up and shutdown decisions. The methodology presented could be applied to any deregulated system based on bids. However, the Spanish regulation [5,6] has been used as reference market model.

In the Spanish system there is a day-ahead market where utilities submit independent hourly bids for each generating unit. Generating units allowed for bidding are the thermal units and the hydro generating units. System marginal price is computed every hour by the intersection of the aggregated demand and supply curves. The market clearing algorithm is based on simple bids, although it incorporates ramp constraints and indivisible bids (minimum stable loads) in order to obtain a quasi-feasible thermal scheduling. An important feature of the market clearing algorithm is the Minimum Income Condition, MIC. If market prices do not yield enough income for a particular unit, this is income above the MIC declared, this unit is not dispatched.

Section 2 describes generating utility objectives. These include only short-term objectives, although also long-term signals, such as stranded costs payments, should also be considered.

Section 3 presents a utility decisions hierarchy to solve the bidding problem. Utility decisions are classified by its temporal range: a weekly problem (WP) which deals with selecting the generating units to be in service, and a daily problem (DP) which handles the problem of finding the optimal hourly bids. Section 4 describes how to model competitors behaviour. Section 5 describes how to represent the revenue function of a utility in the generation market. Section 6 presents in detail how WP is solved, while Section 7 outlines the method for solving DP. Section 8 includes a numerical example where the proposed methodology is applied to a practical case.

2. UTILITY OBJECTIVES

The main utility objective can be defined as a margin maximisation subject to an efficient operation of its generating resources. Hereafter both concepts are explained in detail.

2.1 Margin maximisation

Margin is defined as the difference between income and costs. In this problem, only market revenue and operating costs are considered. Investment costs and possible stranded cost payments are not taken into account in this work.

Weekly margin (p) is defined as the difference between energy sales revenue (r) and operating costs (c) during a week:

$$p = r - c \tag{1}$$

Operating costs are formed by fuel costs, start-up costs and shutdown costs.

Let $D_A(h)$ be the power produced by the utility in hour h and $\pi(h)$ the system marginal price computed in hour h. Weekly income is obtained by adding the products of price and power extended to the 168 hours of the week.

$$r = \sum_{h=1}^{168} \pi(h) \cdot D_A(h) \tag{2}$$

Notice that maximising p is a non-linear and non-convex problem.

2.2 Efficient operation

A utility is most interested in operating its generating resources as efficiently as possible. Therefore, the number of shutdowns and start-ups of thermal plants should be minimised; smooth load curves are preferred for thermal plants; water spills should be avoided, etc. Utilities may obtain efficient operation schedules by means of the adequate bids.

3. UTILITY DECISIONS HIERARCHY

In a centralised system, the problem of selecting the units to be *on* and *off* is the classic unit-commitment problem [7] that can be solved using diverse optimisation techniques. However, in a deregulated system each utility has to decide which units to start-up and when to do it. Once the set of units to be *on* and quantities of water to be produced are determined, it is necessary to elaborate the bids for each unit and day.

The Weekly Problem (WP) faces the self unit-commitment problem in a competitive market. Essentially it is an optimisation problem where the weekly margin is maximised. Each utility has information about its own cost structure. However, competitor utilities real costs are unknown. Past market results are needed to estimate competitor behaviour. Also system demand must be forecasted.

WP is solved using a mixed-integer linear programming formulation where the utility is represented by its real cost structure and competitors by its estimated bidding curves. Water value, provided by long-term models, must also be considered as an input to the WP for those utilities with hydro-resources.

WP determines the start-up and shutdown decisions of the week. These results may be revised if any contingency occurs, such as the failure of a thermal unit, or when the actual competitors behaviour or system demand differ substantially from those expected.

It is important to note that WP not only provides the unit-commitment, but also the expected hourly schedule for each unit. This information can be used in order to bid, in such a way that market clearing results are physically feasible and similar to the expected WP results. However, the risk of obtaining an infeasible dispatch always exists, since the results depend on the competitor offers and system demand, which are never perfectly forecasted. In the Spanish case, the MIC is also obtained computing the expected cost of committed units.

The Daily Problem (DP) is solved every day. The output is the set of bids to be submitted in the wholesale market.

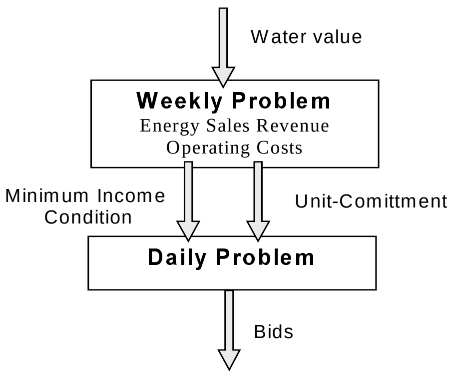

Fig.I Hierarchical structure

4. COMPETITORS BIDDING CURVE

In order to include competition in the model, competitor behaviour is represented by its forecasted bidding curves. The estimation of these curves is based on historical result analysis, particular knowledge of competitor generation structure and competitors short-term strategy. In [1,8] it is shown how generator bidding strategies can be characterised and interpreted.

The single hour problem is shown to illustrate the procedure. Competitors bidding curve in hour h is built by aggregating the bids submitted by competitors. Let D be the expected system demand. Let D_A and D_B be the variables representing the demand supplied by the utility considered and the demand covered by the other utilities, respectively, at hour *h*. Power balance leads to:

$$D = D_A + D_B \tag{3}$$

In Fig.II can be seen the competitors bidding curve. This curve is a step function due to the discrete pairs of price and power submitted by the utilities. In [9] it is suggested to work with a smooth curve, but for the purpose of this paper it is enough to work with a piecewise continuous linear function. When competitors bidding curve is represented with a continuous function, marginal price is univocally obtained fixing competitors power. This property is used to introduce competition into the model.

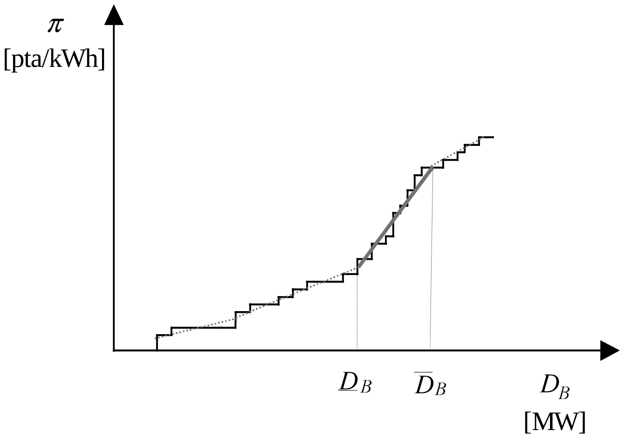

Fig.II Competitors bidding curve

Linear approximation is represented with a dotted line in Fig.II. $\overline{D}_B$ and $\underline{D}_B$ are the expected limits of D_B. If the curve between $\overline{D}_B$ and $\underline{D}_B$ is approximated by one straight line with a slope α and an independent term β, it follows that the marginal system price can be formulated as:

$$\pi = \alpha \cdot D_B + \beta \tag{4}$$

5. REVENUE CURVE APPROXIMATION

Once the marginal system price has been formulated, revenue for utility A in a single hour are:

$$r = \pi \cdot D_A \tag{5}$$

From equations (3), (4), (5) it follows that revenue r can be expressed as a quadratic function of D_A:

$$\begin{aligned} r &= (\alpha \cdot (D - D_A) + \beta) \cdot D_A \\ &= -\alpha \cdot D_A^2 + (\alpha \cdot D + \beta) \cdot D_A \end{aligned} \tag{6}$$

The validity domain of equation (6) is [$\underline{D}_A$, $\overline{D}_A$], where $\underline{D}_A = D - \overline{D}_B$ and $\overline{D}_A = D - \underline{D}_B$.

The revenue function is depicted in Fig.III. However, as unit-commitment problem requires integer variables it is necessary to find a quasi-equivalent linear formulation in order to use a mixed integer linear solver. This is justified by the robustness and ability to deal with big problems of this kind of optimisers.

The revenue curve can be approximated in the interval [$\underline{D}_A$, $\overline{D}_A$] by a set of tangent cuts (see Fig.III). Let T be the index of the tangents. Each tangent cut is defined by its slope m_t and its independent term n_t . As the curve is convex in the validity domain, it is satisfied $\forall t$ that:

$$\begin{aligned} r &\le m_{t1} \cdot D_A + n_{t1} \\ r &\le m_{t2} \cdot D_A + n_{t2} \\ &\vdots \qquad \vdots \\ r &\le m_T \cdot D_A + n_T \end{aligned} \tag{7}$$

When these constraints are introduced in an optimisation problem where variable r is being maximised, the optimal value of r will be either on a vertex defined by the intersection of two of the tangent cuts or on a tangent cut.

The first derivative of equation (6) respect to D_A gives the expression used to compute the slope:

$$m_t = \frac{dr}{dD_A} = -2\alpha \cdot D_A + (\alpha \cdot D + \beta) \tag{8}$$

The independent term is easily obtained imposing that the tangent cut intersects the quadratic curve at the point where slope is calculated.

$$n_t = \alpha \cdot D_A^2 \tag{9}$$

Therefore, tangent cuts are obtained applying equations (8) and (9) to an arbitrary number of D_A values in the validity domain.

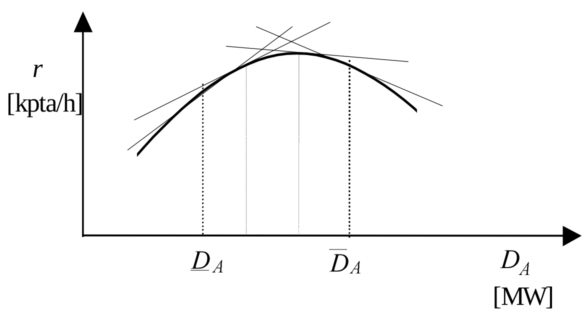

Fig.III Revenue curve approximation by tangents cuts

6. THE WEEKLY PROBLEM

Fuel cost of thermal units is represented by two coefficients: the cost of the thermal unit when it is producing the minimum stable load, and the incremental cost of power produced between the minimum and the maximum output power. This representation corresponds to a linear model.

Each hydro generating bid contain the bids corresponding to a set of hydro plants belonging to the same river. This fact implies that hydro plants scheduling are not directly obtained by the market clearing algorithm. Therefore, it is assumed again that the utilities should be able to find the optimum and feasible operation of its hydro resources. This can be achieved with specific basin models where detailed hydro network constraints are considered.

Hydro units are introduced in the model considering the water values of a set of discrete energy levels.

6.1 Notations:

K	Period index used in scheduling time horizon
I	Index hydro units
J	Index of thermal units
N	Index of hydro levels
T	Index of the revenue curve tangent cut
$D(k)$	System demand requirement in time period k
$D_A(k)$	Demand supplied by the considered utility in period k
$l(k)$	Duration of each period
a_j	Start-up cost of the j-th unit
c_j	Cost of the j-th unit when it is producing the minimum stable load
d_j	Variable cost of the j-th unit
e_j	Shutdown cost of the j-th unit
$\overline{P}_j$	Maximum MW power of the j-th unit
$\underline{P}_j$	Minimum MW stable load of the j-th unit
ur_j	Upper ramp rate limit
lr_j	Lower ramp rate limit
$sr(k)$	Spinning reserve requirement in period k
ct	Thermal operating cost
$v_j(k)$	Commitment state of the j-th unit in k
$y_j(k)$	Start-up decision of the j-th unit in k
$z_j(k)$	Shut-down decision of the j-th unit in k
$p_j(k)$	MW power generated by the j-th thermal unit above the minimum output power in k
$t_j(k)$	MW power generated by the j-th thermal unit
$d_T(k)$	Thermal power produced in k by the consider utility
ch	Hydraulic operating cost
$q_i^n(k)$	MW power generated of the n-th level by the i-th hydro unit in period k
$q_i(k)$	MW power generated by the i-th hydro unit in k
$d_H(k)$	Hydropower produced in period k by the considered utility
$\overline{Q}_i$	Maximum MW power of the i-th hydro unit
$\underline{Q}_i$	Minimum MW power of the i-th hydro unit
υ_i^n	n-th level water value of the i-th hydro unit
E_i^n	Energy limit of n-th level in i-th hydro unit
$m_t(k)$	Slope of the revenue curve tangent cut t in period k
$n_t(k)$	Independent term of the revenue curve tangent cut t in period k
$rp(k)$	Revenue obtained by the considered utility in period k
r	Weekly revenue of the considered utility

6.2 Problem formulation

$$\textit{Maximise} \quad r-(ct+ch) \tag{10}$$

subject to:

- Thermal subsystem constraints
- Hydro subsystem constraints
- Revenue approximation constraints

Thermal subsystem constraints are:

$$ct=\sum_{j\in J}\sum_{k\in K}(a_j y_j(k)+c_j v_j(k) l(k)+d_j p_j(k) l(k)+e_j z_j(k)) \tag{11}$$

$$t_j(k)=\underline{P}\ v_j(k)+p_j(k) \qquad \forall j\ \forall k \tag{12}$$

$$p_j(k)\le(\overline{P}_j-\underline{P})\,v_j(k) \qquad \forall j\ \forall k \tag{13}$$

$$y_j(k)-z_j(k)-v_j(k)=-v_j(k-1) \qquad \forall j\ \forall k \tag{14}$$

$$-ur_j\, l(k)\le p_j(k)-p_j(k+1)\le lr_j\, l(k) \qquad \forall j\ \forall k \tag{15}$$

$$\sum_{j\in J}(v_j(k)\cdot\overline{P}_j-t_j(k))\ge sr(k) \qquad \forall k \tag{16}$$

$$\sum_{j\in J}t_j(k)=d_T(k) \qquad \forall k \tag{17}$$

Equation (11) is the thermal production cost definition. Inequalities (12) and (13) state that committed thermal units should work between their respective minimum and maximum output powers. Equation (14) are logical constraints for the start-up, running and shutdown status. Inequalities (15) limit the ramp rates and (16) provide spinning reserve margins. Equations (17) define for each period, the total thermal production of the considered utility.

Hydro subsystem constraints are:

$$ch=\sum_{i\in I}\sum_{n\in N}\sum_{k\in K}(\upsilon_i^n(k)\cdot q_i^n(k)\cdot l(k)) \tag{18}$$

$$q_i(k)=\sum_{n\in N}q_i^n(k) \qquad \forall i\ \forall k \tag{19}$$

$$q_i(k)\le\overline{Q}_i \qquad \forall i\ \forall k \tag{20}$$

$$q_i(k)\ge\underline{Q}_i \qquad \forall i\ \forall k \tag{21}$$

$$\sum_{k\in K}q_i^n(k)\cdot l(k)\le E_i^n \qquad \forall i\ \forall n \tag{22}$$

$$\sum_{i\in I}q_i(k)=d_H(k) \qquad \forall k \tag{23}$$

Equation (18) is the hydro operating cost definition. Equation (19) defines the power produced each period as the sum of the power produced in each level. Inequalities (20) and (21) set the upper and lower bounds to the power produced by each hydro unit. Inequalities (22) express the energy limits of the different levels. Finally, equation (23) defines for each period, the total hydropower produced by the considered utility.

Revenue approximation constraints are:

$$rp(k) \leq m_t(k)\ D_A(k) + n_t(k) \qquad \forall k\ \forall t \qquad (24)$$

$$r = \sum_{k \in K} rp(k) \cdot l(k) \qquad (25)$$

$$D_A(k) = d_T(k) + d_H(k) \qquad \forall k \qquad (26)$$

Constraints (24) express the revenue curve approximation for each period *k*. Equation (25) express the weekly revenue as the sum of period revenue. Equation (26) defines for each period the power produced by the utility as the sum of thermal and hydro generation.

7. DAILY PROBLEM OUTLINE

Once the weekly problem has been solved it is necessary to build the hourly bids. The daily problem (DP) can be separated in two stages: strategic and technical. The first stage deals with deciding the shape of the 24 aggregated supply curves. The second stage consists in building the bidding curves.

DP receives from the WP solution the unit-commitment and the expected schedule. Bid prices for each generating unit are determined in order to try to recover at least the operating cost. Generally, the lowest bid prices correspond to the minimum stable load of the committed units, in order to avoiding unexpected shutdowns. It follows in the price ordering, the run of the river hydropower, since this energy is lost if it is not produced. Then, the power above the minimum stable load of thermal units, up to the dispatched level obtained in WP. With higher prices, the power between the WP dispatched level and the maximum output level of each unit. Finally, the units not committed by the WP, are assigned the highest bid prices.

WP also provides information about the expected operating cost of thermal units that is used in DP to determine the MIC to be submitted with the bids.

8. APPLICATION EXAMPLE

A practical case is presented in order to illustrate the efficiency of the proposed method. The model has been implemented in GAMS (General Algebraic Modelling System). The optimiser used was CPLEX 4.0.

8.1 Input data

The generation utility analysed in the example has 38 thermal units, 2 nuclear plants and 1 hydro unit. Installed capacity is 10600 MW of coal and oil/gas, 1950 MW of nuclear power and 2000 hydro MW. The range of the costs considered is:

- Variable costs: 1.25 to 5.99 pta/kWh.
- No load cost: 1 to 2.5 Mpta/h.
- Start-up costs: 1.5 to 5 Mpta.
- Shutdown costs: 0.5 to 1.85 Mpta.

Fig.IV shows the thermal and nuclear variable cost versus installed capacity. The units are ordered by its variable cost, thus UNIT1 has the lowest variable cost and UNIT40 the highest. The hydro unit is named UGH1. The hydro energy levels and their water values are shown in Table.I.

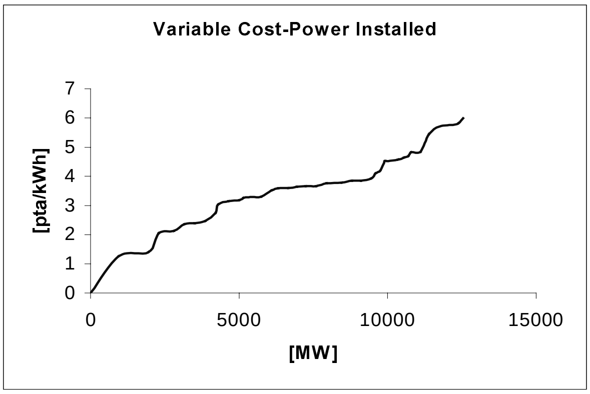

Fig.IV. Thermal variable cost

Table I. Hydro inputs

Level	Energy [MWh]	Water Value [ptas/kWh]
1	16800	0
2	21000	2
3	21000	4

The load used in the example is a 168 hourly load curve. The load curve, shown in Fig.V, begins on Saturday. The initial status for all thermal units is *on*. The algorithm decides which units to shutdown during the weekend and which to start-up on Monday.

Utility market share is expected to take values between the 30% and the 40%. Therefore, competitors bidding curves are only analysed in the interval [60%, 70%]. As described in section 5, each hourly curve is approximated by a straight line. The values of the slope and the independent term of the competitors bidding curves used in the example are shown in Tables II and III, where they are classified by the type of load and day. In order to approximate the hourly revenue, the number of tangent cuts introduced each hour is 10.

Table II. Slope

α [pta/(MW)^{2}h]	*Saturday*	*Sunday*	*Working Days*
Peak	0.5404	0.6486	0.3772
Plateau	0.5513	0.6616	0.4848
Off-peak	0.5623	0.6748	0.5405

Table III. Independent term

β [pta/kWh]	*Saturday*	*Sunday*	*Working Days*
Peak	0.5	0	1.5
Plateau	0	-0.5	0.5
Off-peak	-0.5	-1	0

The size of the problem presented is 36557 single equations, 14956 continuous variables and 20160 integer variables.

8.2 Results

Expected daily market shares obtained are shown in Table IV where also appears the mean market share of peak, plateau and off-peak hours.

Table IV. Expected market share results

Market Share[%]	Sat	Sun	Mon	Tue	Wed	Thu	Fri
Peak	30.6	32.2	32.2	32.2	32.2	32.2	32.2
Plateau	28.9	30.8	31.6	31.9	32.0	31.8	31.2
Off-peak	31.2	30.3	31.8	33.8	33.6	33.6	32.3
Daily	**29.9**	**31.0**	**31.8**	**32.4**	**32.4**	**32.3**	**31.7**

Notice that market share obtained on Saturday during plateau hours is 28.9%, which does not belong to the interval [30%,40%] used for building the revenue tangent cuts. This is so because no market share constraints are included in the WP model. However, the value 28.9% is closed enough to 30% for considering the solution acceptable. If it were not, it would be necessary to analyse the competitors bidding curve in other interval containing the expected market share value.

Table V shows the expected unit-commitment and dispatch of Monday. Start-up decisions are printed in bold. It can be seen that UNIT14 and UNIT15 are not committed due to their no-load costs. Water is allocated in the expected high price hours.

Fig.V shows both the input load curve and the expected marginal price obtained. This price is computed every hour applying equation (4) to the difference between system load and utility power produced in WP.

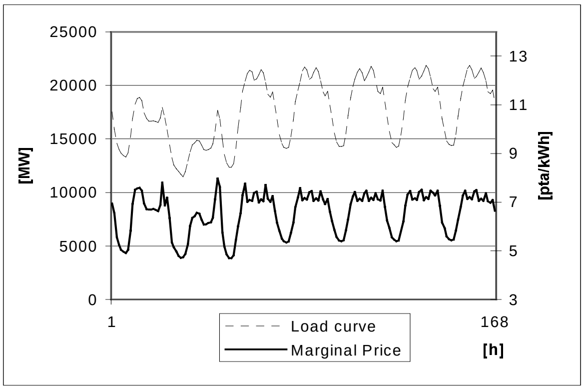

Fig.V. Load curve and expected marginal price

It can be seen that expected marginal price is higher than variable cost of the last units dispatched. This fact is justified because WP tries to maximise weekly margin, and if variable cost were used for paying the generator, no-load costs, start-up costs and shutdown costs would not be recovered.

Computation time for solving the problem was 738 seconds in a Pentium Pro, 132.0 Mb and 233 MHz.

Table V. Expected Monday unit-commitment and dispatch

	h1	h2	h3	h4	h5	h6	h7	h8	h9	h10	h11	h12	h13	h14	h15	h16	h17	h18	h19	h20	h21	h22	h23	h24
UNIT1	950	950	950	950	950	950	950	950	950	950	950	950	950	950	950	950	950	950	950	950	950	950	950	950
UNIT2	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
UNIT3	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350
UNIT4	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
UNIT5	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350
UNIT6	350	350	350	321	334	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350
UNIT7	350	350	319	214	200	292	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350
UNIT8	350	305	200	200	200	200	305	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350
UNIT9	0	0	0	0	0	0	0	0	**80**	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
UNIT10	255	150	150	150	150	150	245	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350
UNIT11	0	0	0	0	0	0	0	0	**305**	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350
UNIT12	0	0	0	0	0	0	0	0	**95**	140	150	150	150	150	150	150	150	150	150	150	150	150	150	140
UNIT13	0	0	0	0	0	0	0	0	**95**	140	150	150	150	150	150	150	150	150	150	150	150	150	150	140
UNIT14	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UNIT15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UNIT16	0	0	0	0	0	0	0	**205**	310	350	350	350	350	350	350	350	350	350	350	350	350	350	350	245
UNIT17	0	0	0	0	0	0	0	**80**	140	200	200	200	200	200	200	200	200	200	200	200	200	200	200	140
UNIT18	0	0	0	0	0	0	0	0	**254**	350	350	350	350	350	350	350	350	350	350	350	350	350	350	250
UNIT19	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UNIT20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
...			...			...			...			...			...			...			...			...
UNIT39	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UNIT40	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UGH1	100	100	100	100	100	100	100	100	100	100	525	754	848	801	550	594	718	866	774	100	100	100	100	100

9. CONCLUSIONS

The paper has presented the hierarchy of the problems to be solved by the utility in a deregulated framework. Two main levels have been identified: a weekly level in which a unit-commitment problem is performed and a daily level, in which the actual bids are produced.

The method to solve the self unit-commitment problem has been explained in detail. In this approach the classical unit-commitment problem is completed with a representation of the competitors behaviour by means of expected bidding curves.

Also, the resulting schedule of the WP can be very near to the actual dispatch of the market, if no large variations of the expected competitor bids and expected system demand occur.

The approach is suitable for real-size systems, as shown in the example.

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