An Active / Reactive Power Market Dispatch Model Including Soft Constraints

Mário Helder Gomes
Escola Superior de Tecnologia de Tomar, Instituto Politécnico de Tomar
Quinta do Contador, Estrada da Serra, 2300 Tomar, Portugal, mgomes@ipt.pt

João Tomé Saraiva
INESC Porto and Faculdade de Engenharia da Universidade do Porto, Rua Dr. Roberto Frias, 4200-465 Porto, Portugal, jsaraiva@fe.up.pt

ABSTRACT. This paper describes an active / reactive dispatch model based on bids transmitted by market agents to the Market Operator. The Market Operator economic schedule is then conveyed to the System Operator in order to evaluate its technical feasibility. If it is unfeasible, the System Operator runs a secondary market based on adjustment bids aiming at regaining feasibility while changing as little as possible the initial economic schedule. This secondary market is modeled as a non-linear optimization problem including the AC power flow equations, branch flow and nodal voltage limits as well as constraints related with the capability curve of synchronous generators. This problem is converted into a Symmetric Fuzzy Decision formulation admitting that branch flow and nodal voltage limit constraints have a soft nature. The resulting problem is solved using a Sequential Linear Programming, SLP, approach. The paper includes a case study based on the 24 bus IEEE Test System to illustrate its application and interest of this approach to restructured power systems.

KEYWORDS. Active/reactive dispatch, symmetric fuzzy model, Sequential Linear Programming.

1. INTRODUCTION

Since the early 90's, power systems have been going through an unbundling process that restructured traditional vertically integrated companies, and identified a number of activities as generation, transmission and distribution, retailing, technical and market coordination. In this new structure, generation and retailing are provided in a competitive basis and the agents in these two areas relate themselves through centralized forward markets with different time horizons and by bilateral contracts. These markets are traditionally related with active power and they aim at identifying a schedule that is expected to be optimal from an economic point of view giving the competition in this sector. This also means there is a separation between commercial and technical functions, in the sense that most markets are organized in a set of sequential activities, most of them developed in the day before the one in which operation decisions are implemented. This means that the purely economic schedules obtained by the day-ahead market or associated to bilateral trades are conveyed to the System Operator to be validated from a technical point of view. Once this is accomplished, the System Operator schedules ancillary services, namely reserves and reactive power / voltage support.

Such a separation between commercial and technical activities poses a number of difficulties and can potentially create inefficiencies. In fact, electricity is not a true commodity as it is not possible to store it in meaningful quantities, it has to be generated at the same moment it is consumed and the connection between demand and supply is made through networks imposing physical laws regarding which the flows have to comply with. In most electricity markets, reactive power / voltage support is not the main focus of concern. This is mainly due to the difficulty in pricing reactive power and to the belief that its economic impact is reduced if compared with active power. It is also recognized that reactive power has a stronger technical accent so that it is not easily marketed. The importance of reactive power started to rise as long as the number and the installed capacity of wind parks

having asynchronous generators started to increase. This issue is even more serious since most of these parks are connected to remote weak distribution networks and behave as reactive power loads. As a result, distribution companies started to impose connection requirements, for instance, in terms of limiting the reactive power demand to a percentage of the active output in peak and full hours.

In general, the coupling between active and reactive dispatches is being recognized again due to a number of reasons among which we can consider the capability diagram of synchronous generators and the thermal limit of network branches. The capability diagram is rather important because the active power scheduled by the Market Operator may have to be changed if a generator has to comply with a reactive power requirement determined by the System Operator. This leads to the so called opportunity costs. This means that this generator would face a reduction of its expected revenue that should be compensated by some sort of reactive power based remuneration.

This paper recognizes that active and reactive dispatches are intrinsically coupled and aims at scheduling reactive power using the economic schedule prepared by the Market Operator as well as adjustment bids to be used by the System Operator if necessary to alleviate security or operation constraints. This leads to an optimization model based on bids transmitted by market agents so that one can conduct this process in a transparent way while complying with system requirements.

2. REACTIVE POWER SCHEDULING

Recognizing the importance of reactive power, several publications describe models to dispatch and to value it. For instance, (Dandachi et al, 1996) proposed a reactive power optimization model based on generators MVAr piece-wise cost curves. In (Ahmed and Strbac, 2000) it is presented a linear programming security constrained reactive OPF model to allocate reactive support on a competitive basis. In (Liu and Guan, 1997) it is described another OPF problem including power flow equations, security constraints, several types of controls and adopting a fuzzy set based approach to model constraints having soft limits. The role of control devices is also analysed in (Zhang and Ren, 2005). These authors aim at avoiding obtaining reactive power schedules that imply an excessive number of operations of those controls turning difficult the implementation of these strategies in real time.

In (Hao et al, 1997), the authors address the characteristics of reactive power / voltage support in terms of its local nature and of the conflicting objectives to establish a price for it. These authors propose several approaches to price reactive power including imposing performance requirements and connection standards or the creation of reactive power markets for each control area. In line with this approach, (Doña and Paredes, 1991) describe an approach to compute active and reactive nodal marginal prices. In (Venkatesh et al, 2000), they are considered two objectives to dispatch reactive power: the minimization of active power losses and the maximization of a voltage stability margin.

In (Lamont and Fu, 1999), (Silva et al, 2001), (Gross et al, 2002), (Zhong and Bhattacharya, 2002) and (El-Araby et al, 2005) the authors discuss different ways of organizing reactive power costs in terms of explicit and implicit ones and also considering opportunity costs related with areas of the capability diagram of generators in which meeting a reactive requirement implies a reduction of the active output leading to a reduction of the revenue.

Finally, recognizing the coupling between active and reactive power and the difficulty in dealing with system constraints, (Miguélez et al, 2004) detail the activities of the Spanish TSO to validate the Market Operator dispatch while enforcing system constraints. The authors propose getting a final solution in two stages. In the first one, they obtain a feasible solution re-dispatching generators and minimizing the total system cost. Once this is guaranteed, voltage control resources are fine tuned for each hour of the next day by running an LP based OPF minimizing transmission losses.

3. MATHEMATICAL MODEL

3.1 General Description

This section describes the formulation of the optimization problem to be solved by the System

Operator. Before detailing this model, we address a number of issues used in this formulation including the uniform price auction used to run the day-ahead market, the capability curve of synchronous generators, the adjustment bids and the use of fuzzy sets to model soft constraints.

3.2 Market Operator Uniform Price Auction

As referred before, Electricity Markets are organized in terms of a set of sequential activities to define the operation conditions for day n. In day n-1, the Market Operator receives information regarding selling and buying bids. In their simplest format, bids include pairs (price, quantity). The price corresponds to the maximum price loads admit to pay or the minimum price generators admit to receive while quantity is the power desired by loads or the generators available power. In this simplest format, the economic scheduling for one trading period can be modelled by (1) to (4).

$$\max \quad Z = \sum_{j=1}^{N_D} Cd_j . Pd_j - \sum_{i=1}^{N_G} Cg_i . Pg_i \tag{1}$$

$$\text{subj to} \quad 0 \le Pd_j \le Pd_j^{bid} \tag{2}$$

$$0 \le Pg_i \le Pg_i^{bid} \tag{3}$$

$$\sum_{j=1}^{N_D} Pd_j = \sum_{i=1}^{N_G} Pg_i \tag{4}$$

In this formulation, Cd_j and Cg_i are the buying and selling prices, Pd_j^{bid} and Pg_i^{bid} are the bidding demand and generation quantities, Pd_j and Pg_i are the demand and generation values at the final solution and N_D and N_G are the number of buying and selling bids. The objective function (1) aims at maximizing the Social Welfare Function, Z, corresponding to the surplus between the aggregated demand and generation curves (shaded area in Figure 1). This objective function is subjected to limits on the demand (2) and on the generation (3) and to a demand / supply balance equation (4).

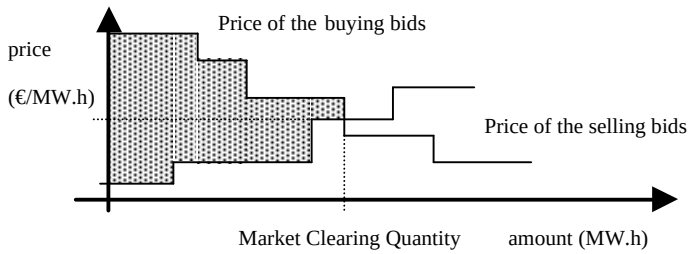

Figure 1. Aggregated demand and supply curves in an uniform price auction.

This simple auction process can be enhanced by structuring generator bids in a number of blocks, each one representing a pair (price, quantity) so that it is possible to follow generator cost curves in a more accurate way. Simple bids can also be substituted by complex ones by including extra information related for instance with ramps. As a result, the 24 hourly schedules are coupled so that more involving search procedures have to be used to get the final global solution.

3.3 Synchronous Generator Capability Curve

Several electricity markets are structured in a number of sequential activities usually assigned to different entities. In particular, the Market Operator runs the day-ahead market while the System Operator manages ancillary services, as voltage control and reactive support. In this scope, the System Operator can require a generator to fulfill a certain reactive power but that may be impossible given the active power previously allocated in the day-ahead active power market. This means that the referred separation of functions must be considered carefully since the operation of synchronous generators are determined by PQ capability curves as the one sketched in Figure 2.

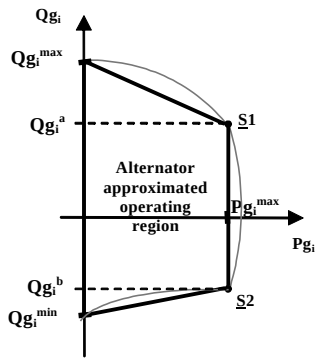

Figure 2. Synchronous generator capability curve.

Capability curves result from several constraints determining the operation of synchronous generators. The diagram in Figure 2 considers three curves. Curve 1 between Qg_i^{max} and $\underline{S}_1$ represents the rotor field current limit. Curve 2 from $\underline{S}_1$ to $\underline{S}_2$ is the armature limit and Curve 3, the arc between Qg_i^{min} and $\underline{S}_2$, represents the stability limit. In view of this diagram, a reactive power requirement can be unfeasible, although both the P and the Q individual limits are not violated. If a particular generator has to reduce its active output regarding the Market Operator schedule, then its expected revenue is also reduced. This corresponds to the opportunity costs referred in section 2.

3.4 Adjustment Bids

If the schedule prepared by the Market Operator leads to the violation of any security or operation constraints, then the System Operator has to change that schedule to regain feasibility. This process can be conducted in a more transparent way if it is based on market mechanisms, namely using adjustment bids provided by generators and loads. Generator adjustment bids include the acceptable maximum variation, vg_i^{tol}, that the Market Operator based schedule can suffer together with an adjustment price, Cg_i^{adj}. In case a generator was not dispatched by the Market Operator, its maximum possible adjustment will correspond to a percentage of its installed capacity.

Apart from generator adjustment bids, power system constraints can also be alleviated if one admits load adjustments. This is not new since several systems admit interruptible contracts meaning that some consumers accept reducing their demand if they are paid a pre-specified price. Admitting load adjustments contributes to increase the flexibility that the System Operator has to regain feasibility and it certainly increases the competition and liquidity of this secondary market.

3.5 Soft Constraints

For some limit constraints, we can specify leeways meaning that one accepts some degree of violation of the initial crisp limits. This flexibility can be introduced using fuzzy models as described in (Zimmermann, 1992).

As an example, on the left of Figure 3 it is sketched the membership function of a branch flow limit. Till x_1 the membership value is 1 meaning that it has the maximum acceptance degree. Values in $[x_1, x^{max}]$ are still accepted but the membership degree decreases to 0.

The right side of Figure 3 illustrates the possible range of the voltage in node i. Voltages in $[V_{i1}; V_{i2}]$ have the maximum membership degree. Voltages lower than V_{i1} or higher than V_{i2} can still be accepted but their membership degree decreases to 0. From a mathematical point of view, these two membership functions can be modeled by (5) and (6).

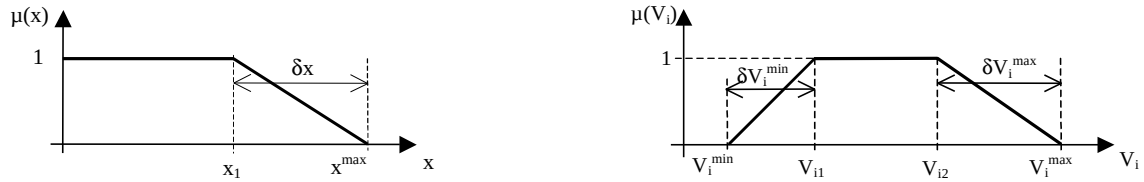

Figure 3. Membership function of a branch flow limit (left side) and voltage limits (right side).

$$\mu(x) = \begin{cases} 1, & \text{if } x \le x_1 \\ [0;1[, & \text{if } x_1 < x \le x^{max} \\ 0, & \text{if } x > x^{max} \end{cases} \tag{5}$$

$$\mu(V_i) = \begin{cases} 1, & \text{if } V_{i1} \le V_i \le V_{i2} \\ [0;1[, & \text{if } V_i^{min} \le V_i < V_{i1} \text{ or } V_{i2} < V_i \le V_i^{max} \\ 0, & \text{if } V_i < V_i^{min} \text{ or } V_i > V_i^{max} \end{cases} \tag{6}$$

3.6 Mathematical Formulation

We will now detail the mathematical model used by the System Operator if the schedule prepared by the Market Operator is unfeasible. It is important to clarify that this model is based on the economic schedule previously prepared by the Market Operator, meaning that the separation between the Market and the System Operators is preserved. It should also be referred that in the implementations in force in several countries there is a first phase related with the establishment of bilateral contracts or bidding to the Day-ahead Market that leads to the economic desired operation point reflecting the so-called "invisible hand of the market". On a second step, the System Operator receives all technical data regarding this economic schedule and evaluates it from a purely technical point of view. This means checking voltage limits or branch flow limits, for instance. If, for some reason, this economic schedule is unfeasible, then regulations determine some process of changing injections in order to regain feasibility. This means that in this paper we are actually proposing a new approach to perform this technical evaluation while assigning adjustments to the injections only if necessary from a technical point of view.

As referred in the previous paragraph, the developed model requires knowing an operation point of the system. This point is obtained running an initial power flow study using the active schedule provided by the Market Operator. The formulation (8) to (17) results from a crisp one described in (Gomes and Saraiva, 2005) in which the objective function is given by (7).

$$FO = \sum_{k=1}^{Nl} \Delta pij_k(\Delta V, \Delta\theta).\rho^{MO} + \sum_{i=1}^{Ng} |\Delta Pg_i|.Cg_i^{adj} + \sum_{j=1}^{Nd} |\Delta Pd_j|.Cd_j^{adj} \tag{7}$$

The first term in (7) represents the linearized variation of active losses in terms of voltage and phase variations, admitting that Nl is the number of branches in the system. The variation of losses is multiplied by the clearing price of the Market Operator auction, ρ^{MO}. The second and the third terms represent the cost of generator and load adjustments in terms of adjusted quantities and adjustment prices.

When adopting this objective function, it becomes clear that the economic schedule prepared by the Market Operator will only be changed if necessary, since the adjustment costs will in fact correspond to penalty terms. This means once again that this model considers the economic schedule prepared by the Market Operator as the basic one, so that we will only admit to alter it if necessary and, in this case, as little as possible.

Adopting a similar idea as the one in Figure 3, the original objective function (7) is converted into a soft constraint (9) using FO_{des} (the maximum value that the objective function can take while still having a maximum satisfaction degree) and δ^{FO} (the admitted leeway). Constraints (10) represent the voltage minimum and maximum limits admitting leeways $\delta^{V\min}$ and $\delta^{V\max}$. Constraints (11) represent the technical limits of generators. Constraints (12) impose the maximum value of generator adjustments, respectively for generators already dispatched by the Market Operator and not yet dispatched. Constraints (13) represent the linearized lower and upper curves of the generator capability curve referred in 3.3. Constraints (14) represent the possible adjustment of load values indicating that, if necessary, load can be curtailed. However, one can specify that only part of a load connected to a bus will eventually be curtailed by only changing the lower limit of constraint (14).

Constraints (15) represent the soft limits of the branch i-j apparent power once again formulated in terms of the satisfaction degree μ and of the corresponding leeway, δ^{Sij}. The expression of the apparent power flow in branch ij is linearized using the first terms of its expansion in Taylor Series. Constraints (16) correspond to the linearized active and reactive power injection equations once again established using the first terms of their expansion in Taylor Series. Finally, the membership degree μ varies from 0 to 1.

$$\text{Max } \mu \tag{8}$$

$$\text{subj. } FO + \mu.\delta^{FO} \le FO_{des} + \delta^{FO} \tag{9}$$

$$\Delta V_i - \mu \times \delta^{V\,min} \ge \Delta V_i^{min} - \delta^{V\,min} \text{ and } \Delta V_i + \mu \times \delta^{V\,max} \le \Delta V_i^{max} + \delta^{V\,max} \tag{10}$$

$$\Delta Pg_i^{min} \le \Delta Pg_i \le \Delta Pg_i^{max} \tag{11}$$

$$-\frac{v_i^{tol}}{100} \times Pg_i^{MO} \le \Delta Pg_i \le \frac{v_i^{tol}}{100} \times Pg_i^{MO} \text{ and } \Delta Pg_i \le \frac{v_i^{tol}}{100} \times Pg_i^{max} \tag{12}$$

$$Qg_j^{min} + \frac{Qg_j^{b} - Qg_j^{min}}{Pg_i^{max}} \cdot (Pg_j^{MO} + \Delta Pg_j) \le Qg_j \le Qg_j^{max} - \frac{Qg_j^{max} - Qg_j^{a}}{Pg_i^{max}} \cdot (Pg_j^{MO} + \Delta Pg_j) \tag{13}$$

$$-Pd_j^{MO} \le \Delta Pdj \le 0 \tag{14}$$

$$\Delta S_{ij}(\Delta V, \Delta\theta) \ge \Delta S_{ij}^{min} \quad \text{and} \quad \Delta S_{ij}(\Delta V, \Delta\theta) + \mu \times \delta^{Sij} \le \Delta S_{ij}^{max} + \delta^{Sij} \tag{15}$$

$$\Delta P_i^{inj}(\Delta V, \Delta\theta) = \Delta Pg_i - \Delta Pd_i \quad \text{and} \quad Q_i^{inj}(V, \theta) = Qg_i - Qd_i \tag{16}$$

$$0 \le \mu \le 1 \tag{17}$$

4. SOLUTION APPROACH

The optimization problem that the System Operator has to solve is non linear due to the presence of the AC power flow equations, the branch flow limit constraints and the constraints related with the curves 1 and 3 of the capability diagram of each generator. The formulation (8-17) results from that original non-linear problem after linearizing those constraints so that one can now use Sequential Linear Programming, SLP, to solve it. The corresponding algorithm evolves as follows:

I. in the first place, the Market Operator runs the auction described in 3.2 based on simple bids transmitted by generators and loads. This will lead to an initial active power schedule only reflecting economic issues. This schedule is then conveyed to the System Operator that runs a power flow study;

II. if there is any violation of security or operation constraints, the System Operator linearizes non-linear constraints of the problem, namely the AC power flow equations (16), the branch limit constraints (15) and the curves of the capability diagram of each synchronous generator (13). This linearization is done around the operation point identified in the power flow study referred in step I and leads to the formulation (8) to (17);

III. the resulting linear optimization problem (8) to (17) is solved in order to maximize the satisfaction degree μ and to compute generation, demand, voltage and phase adjustments. These values are then used to update active and reactive generations and demand, as well as voltages and phases;

IV. if the adjustments obtained in this iteration are smaller than specified tolerances, then the iterative process converged. If convergence was not yet obtained, it is run a new power flow study to get a new operation point after which we linearize constraints and get back to step III.

5. CASE STUDY

The formulation described in Sections 3 and 4 was tested using the IEEE 24 bus/38 branch Test System (the original data can be obtained in (IEEE, 1979)). In these simulations we used 0.90 and 1.10 pu for the voltage limits. Table 1 includes load data (active and reactive powers, bidding price and adjustment price). Table 2 includes the generator bidding blocks, each one including a pair (quantity/price) and the adjustment bids (maximum adjustment in percentage and adjustment price). Table 3 presents the points of the approximated capability curve of each generator referred in 3.3.

Table 1. Demand bids for the Market Operator and for adjustments.

Bus j	Pdj^{bid} (MW)	Qdj (MVAr)	Cdj (€/MW.h)	Cdj^{adj} (€/MW.h)	Bus j	Pdj^{bid} (MW)	Qdj (MVAr)	Cdj (€/MW.h)	Cdj^{adj} (€/MW.h)
1	108.0	31.5	80.0	295.0	10	195.0	56.9	35.0	288.0
2	97.0	28.3	93.0	290.0	13	265.0	77.3	20.0	287.0
3	180.0	52.5	99.0	289.0	14	194.0	56.6	92.0	305.0
4	74.0	21.6	88.0	288.0	15	317.0	92.5	94.0	301.0
5	71.0	20.7	101.0	296.0	16	100.0	29.2	92.0	294.0
6	136.0	39.7	50.0	300.0	18	333.0	97.1	90.0	296.0
7	125.0	36.5	91.0	285.0	19	181.0	52.8	36.0	298.0
8	171.0	49.9	85.0	295.0	20	128.0	37.3	96.0	291.0
9	175.0	51.0	75.0	296.0					

Table 2. Structure of the generator selling bids.

Bus i	$Pgi^{bid\ 1}$ (MW)	$Cgi^{\ 1}$ (€/MW.h)	$Pgi^{bid\ 2}$ (MW)	$Cgi^{\ 2}$ (€/MW.h)	$Pgi^{bid\ 3}$ (MW)	$Cgi^{\ 3}$ (€/MW.h)	Vgi^{tol} (%)	Cgi^{adj} (€/MW.h)
1	94.0	50.0	150.0	75.0	192.0	90.0	40.0	110.0
2	96.0	60.0	154.0	80.0	192.0	90.0	40.0	115.0
7	150.0	10.0	230.0	25.0	300.0	35.0	40.0	120.0
13	300.0	15.0	450.0	24.0	591.0	35.0	40.0	105.0
15	90.0	10.0	160.0	22.0	215.0	35.0	40.0	100.0
16	100.0	15.0	155.0	35.0	---	---	40.0	112.0
18	250.0	37.0	350.0	45.0	400.0	60.0	40.0	130.0
21	250.0	35.0	350.0	44.0	400.0	60.0	40.0	160.0
22	150.0	5.0	225.0	15.0	300.0	35.0	40.0	103.0
23	300.0	15.0	550.0	24.0	660.0	35.0	40.0	118.0

Table 3. Points of the approximated capability curve of each generator.

Bus 1	Pgi^{max} (MW)	Qgi^{max} (MVAr)	Qgi^{a} (MVAr)	Qgi^{b} (MVAr)	Qgi^{min} (MVAr)	Bus i	Pgi^{max} (MW)	Qgi^{max} (MVAr)	Qgi^{a} (MVAr)	Qgi^{a} (MVAr)	Qgi^{min} (MVAr)
1	192.0	130.0	90.0	-70.0	-100.0	16	155.0	100.0	70.0	-55.0	-80.0
2	192.0	120.0	80.0	-60.0	-90.0	18	400.0	250.0	150.0	-120.0	-200.0
7	300.0	200.0	150.0	-160.0	-180.0	21	400.0	250.0	150.0	-100.0	-200.0
13	591.0	250.0	150.0	-150.0	-200.0	22	300.0	220.0	125.0	-100.0	-180.0
15	215.0	150.0	120.0	-85.0	-100.0	23	660.0	300.0	185.0	-165.0	-280.0

Table 4. Market Operator economic dispatch.

Bus i	Pdi^{MO} (MW)	Pgi^{MO} (MW)	Bus i	Pdi^{MO} (MW)	Pgi^{MO} (MW)	Bus i	Pdi^{MO} (MW)	Pgi^{MO} (MW)
1	108.0	0.0	8	171.0	---	18	333.0	0.0
2	97.0	0.0	9	175.0	---	19	181.0	---
3	180.0	---	10	12.01	---	20	128.0	---
4	74.0	---	13	0.0	579.62	21	---	238.03
5	71.0	---	14	194.0	---	22	---	290.64
6	136.0	---	15	317.0	206.76	23	---	649.31
7	125.0	290.89	16	100.0	146.76			

In the first place, the Market Operator ran an uniform price auction, that led to the results in Table 4. The market-clearing price was 35 €/MW.h. Using these results, we performed two simulations. In first one there is no congestion on the transmission system. On the second one, the apparent power

limit of branch 7-8 was reduced from 175 to 150 MW leading to a congested situation.

In the first simulation, Case 1, we specified the following values: $FO_{des} = 7500€$, $\delta_{des} = 500€$, $\delta^{V\,min} = \delta^{V\,max} = 0.0pu$, $\delta^{Sij} = 10\%$. This means that one does not admit any leeway on the voltage limits. Table 5 presents the voltages, phases and active and reactive generated and load powers. The final value of the objective function was 7700.95 €, the satisfaction degree is 0.598 and the active transmission losses are 53.11 MW.

In the second simulation, Case 2, we specified the following values: $FO_{des} = 11500€$, $\delta_{des} = 500€$, $\delta^{V\,min} = 0.0pu$, $\delta^{V\,max} = 0.05pu$ and $\delta^{Sij} = 20\%$. Table 5 also presents the corresponding final values. In this case, the final value of the objective function was 11931.30 €, the satisfaction degree is 0.137 and the active transmission losses are 57.08 MW.

Table 5. Results obtained for the two simulations (Case 1 and Case 2).

	Case 1						Case 2					
Bus i	V_i (pu)	θ_i (deg)	P_{di}^F (MW)	Q_{di}^F (MVAr)	P_{gi}^F (MW)	Q_{gi}^F (MVAr)	V_i (pu)	θ_i (deg)	P_{di}^F (MW)	Q_{di}^F (MVAr)	P_{gi}^F (MW)	Q_{gi}^F (MVAr)
1	1.055	-18.08	108.0	31.50	53.11	118.93	1.007	-18.76	108.0	31.50	72.97	114.65
2	1.055	-18.34	97.0	28.29	0.0	120.0	1.006	-19.11	97.0	28.29	0.0	120.0
3	1.009	-12.99	180.0	52.50	---	---	0.973	-13.59	180.0	52.50	---	---
4	1.010	-15.41	74.0	21.58	---	---	0.957	-16.20	74.0	21.58	---	---
5	1.022	-14.96	71.0	20.71	---	---	0.968	-15.55	71.0	20.71	---	---
6	0.999	-14.08	136.0	39.67	---	---	0.941	-14.73	136.0	39.67	---	---
7	1.100	-4.73	125.0	36.46	290.89	115.53	0.924	-2.97	125.0	36.46	275.00	37.03
8	1.035	-9.23	171.0	49.88	---	---	0.905	-9.56	171.0	49.88	---	---
9	1.022	-8.98	175.0	51.04	---	---	0.969	-9.34	175.0	51.04	---	---
10	1.029	-8.45	12.0	3.50	---	---	0.973	-8.53	12.0	3.50	---	---
11	1.044	-2.37	---	---	---	---	1.008	-2.06	---	---	---	---
12	1.046	-0.02	---	---	---	---	1.007	0.45	---	---	---	---
13	1.094	5.69	0.0	0.0	579.63	151.92	1.063	6.42	0.0	0.0	579.63	151.93
14	1.046	-3.73	194.0	56.58	---	---	1.026	-3.59	194.0	56.58	---	---
15	1.079	-1.71	317.0	92.46	206.76	121.15	1.077	-1.63	317.0	92.46	206.76	121.16
16	1.079	-1.26	100.0	29.17	146.76	71.59	1.075	-1.14	100.0	29.17	146.76	71.60
17	1.093	-0.89	---	---	---	---	1.097	-0.83	---	---	---	---
18	1.100	-1.54	333.0	97.13	0.0	200.19	1.109	-1.51	333.0	97.13	0.0	200.38
19	1.074	0.24	181.0	52.79	---	---	1.066	0.99	181.0	52.79	---	---
20	1.086	4.14	128.0	37.33	---	---	1.075	4.54	128.0	37.33	---	---
21	1.100	0.0	---	---	238.03	76.76	1.109	0.0	---	---	238.03	130.79
22	1.100	5.39	---	---	290.64	-14.75	1.109	5.32	---	---	290.64	-9.37
23	1.100	6.59	---	---	649.31	149.43	1.088	7.09	---	---	649.31	186.86
24	1.041	-5.73	---	---	---	---	1.025	-5.75	---	---	---	---

The adoption of the SLP based approach described in section 4 proved to be very accurate. In fact, regarding Case 1 the active losses are balanced in bus 1 and the SLP approach leads to a value of 53.112 MW as indicated in Table 5. The value obtained by running a power flow study for the same injections coincided with the previous one. Regarding Case 2, the SLP approach lead to 57.434 MW while the result of a power flow study was 57.440 MW. A similar accuracy was also obtained for other case studies ran using different test systems.

Finally, the Case 2 problem converged in 36 iterations with a computation time of about 10 s in a Pentium IV 2,8 GHz. For a congested test case based on the IEEE 118 test system the number of iterations was 86 and the total CPU time was 250 s in the same type of computer. This suggests that there would be no difficulty in applying this approach in real power systems given that the System Operator should run this adjustment problem in an off-line mode in the day before.

6. CONCLUSIONS

In this paper, we presented an active / reactive dispatch model based on bids transmitted by generators, retailers and consumers to be used by the System Operator in case the economic schedule prepared by the Market Operator violates security or operation constraints. This model explicitly recognizes that decoupling active and reactive allocation procedures, as it is typical in most electricity market implementations, may lead to inefficiencies or cause reductions on the revenues of generators since they have to comply with their capability diagram. This reduction originates opportunity costs for which generation entities should be compensated, in case a reactive power requirement imposed by the System Operator can only be accomplished if the active power scheduled by the Market Operator is reduced. The developed model overcomes these difficulties when explicitly considering the capability diagram of generators as well as generation adjustment prices. Apart from that, the technical validation study conducted by the System Operator is based on adjustment bids from both generators and demand, so that this activity is performed in a more transparent and liquid way. Finally, it is also important to stress that branch flow and voltage limit constraints are modeled using fuzzy concepts to deal with their possible soft nature. All these aspects contribute to enlarge the realism of this model, thus increasing its interest to real power systems.

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