

A Combined Pool/Bilateral/Reserve Electricity Market Operating Under Pay-as-Bid Pricing

Fabio Stacke and Pablo Cuervo, *Senior Member, IEEE*

Abstract—A pricing model considering the simultaneous interaction of pool, bilateral and reserve markets in a power system is presented. The model is able to work under the classical marginal pricing (MP) or under the “pay-as-bid” (PAB) pricing. In the PAB pricing approach, an integration process involves an ac optimal power flow (OPF) for obtaining awarded bids in the pool and reserve market considering the presence of long-term firm bilateral contracts. As a result, prices of energy and reserve services incorporate the influences of topology, voltage levels, losses, capacity limits of generators and transmission lines. Results show that agents can plan their portfolios based on prices reflecting the impact of supplying several electricity services and associated costs of resources in several operation scenarios and bid strategies. From the perspective of the system regulator, the minimization of payments by PAB ensures the supply of energy, transmission losses and reserve requirements besides enforcing financial adequacy. Numerical cases are presented for evaluating the model.

Index Terms—Ancillary service, average price, bilateral and reserve markets, marginal pricing, pay as bid, pool, revenue and payment portfolios.

I. INTRODUCTION

IN recent years, electricity markets have developed important economic and operational tools looking for efficiency in terms of determining prices that represent the costs of production and transmission of energy. This effort has been oriented to obtain corresponding payments and revenues that truly reflect the use of services and provide economic signals for future investments in infrastructure. From the structural point of view, there are two main forms of markets auctions for trading energy and ancillary services [1]. One is based on a separate markets and the other is based on a strong coordination of both markets. In the first one, the provision of services is left to secondary markets after the main energy auction is defined. In this structure, energy and services are provided through an unbundled mechanism. Because of the free participation of traders in each market for each service, opportunity for arbitrage motivates traders to move from one market to another. The possible advantage of this auction structure is that the voluntary participation of traders in markets could provide efficiency, like in a pool, avoiding using complex optimization tools. Some systems operating under this structure are in Australia, Scandinavia, California (1998–2000), and Brazil. In the second kind of market auctions, electricity

market products (energy and ancillary services) are procured simultaneously through central auctions. The purpose of this type of auction is based on the fact that optimization is necessary to minimize costs of generation, transmission and reserves while meeting the demand and ensuring reliability. The advantage of this combined market is the quality of the resulting prices which better reflect the cost of resources due to the inherent relationship between energy and ancillary services. Several systems operate with this structure like in New York, New England, MISO and PJM. Also, several suggested models have followed this trend [1].

From the theoretical point of view, two approaches are mainly followed for pricing electricity services: One of them is the classical marginal pricing (MP) where nodal prices represent the cost of the last MW to be supplied. The other is the “pay-as-bid” (PAB) pricing which is the way forward bilateral contracts are negotiated. Whether one or the other should be followed has been subject for debate. For instance, in [15] it is demonstrated that in the general case when the load is not precisely predicted and without considering the transmission network, the expected profits and load payments are the same under MP and PAB but the risk of not reaching these values are greater under MP. Recently, PAB pricing has showed an increasing interest because some markets like in Wales and England are essentially based on bilateral agreements that are traded following a PAB approach. Agents agree to participate in this type of market with the motivation of minimizing the volatility of nodal prices. Moreover, the system regulator is also interested in obtaining financial adequacy (i.e., reconciliation between revenues and payments) as commented in [4] and [5]. Because of these characteristics, the PAB strategy is currently being considered as an alternative in some real systems.

This paper analyzes the characteristics of a pricing model designed for working under the classical MP and the PAB strategies in a combined market structure involving the presence of long-term forward physical bilateral contracts (not financial contracts), and short term trades like pool and ancillary reserve services. The model allows studying the implications of the combined market on the operation and the resulting economic indexes such as prices, revenue and payment portfolios. The purpose of the model is to make use of the advantages of centralized market coordination and the potential benefits of using the PAB pricing strategy like: achieving less risk in supplying loads, adequate price stability and financial adequacy. It is not the focus here to mathematically proof which of the pricing approaches should be followed but instead observing their price behavior in the combined market. The purpose of using the marginal pricing strategy here is to provide a base (or reference) of comparison for analyzing the behavior of PAB in terms of financial adequacy and price volatility. The formulation of the

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F. Stacke is with the Brazilian Electricity Regulatory Agency—ANEEL, Brasília, Brazil (e-mail: fabiostacke@aneel.gov.br).

P. Cuervo is with the Department of Electrical Engineering, University of Brasília, Brasília, Brazil (e-mail: pablo@ene.unb.br).

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model is an extension of a previous work presented in [4] and [5] in terms of including the ancillary reserve market with its characteristics and associated system requirements.

The ancillary reserve market is composed of several reserve services as presented in [1], [2], and [16]. The characterization and requirements of these services are previously defined by the regulator and are based on the quality of their response; i.e., faster response reserves are graded as higher quality or higher value (this classification is followed by CAISO, New England ISO, PJM, NYISO, among others). In the reserve market, the allowed substitution among some reserve services are based on agents' bids that avoid price reversal between reserve services [1], [16]. The model presented here considers that a unit commitment (UC) problem has been solved previously for a particular hour and that its results are used for applying the pricing methodology which is based on an OPF and integration process. It is not the purpose here to suggest a model for solving the general scheduling problem. Other approaches like in [14], [17], and [18] suggest models for scheduling reserve services simultaneously with the solution of the UC problem in a multi-period and MP context without considering the presence of bilateral contracts and their impact on the network operation.

The PAB version of this model is implemented through an integration process based on the Aumann–Shapley [3], [5] technique using an ac-OPF that takes into consideration the nonlinear characteristic existing in the transmission network due to transmission losses, capacity limits, reactive power and voltage behaviors. These features are not present in simpler PAB schemes such as *pro-rata*. The integration process also permits to unbundling the use and prices of several services including transmission bilateral contracts losses, pool dispatch, and capacity availability for reserve services.

The previously mentioned characteristics of the model allow market agents to plan their portfolios by knowing how prices of electricity services interact in several possible operation scenarios. Moreover, from the independent system operator (ISO) point of view, it is possible to estimate the impact of different levels of total bilateral trades, pool load and reserve requirements on prices and generation and transmission capacity while enforcing price stability and financial adequacy. A detailed mathematical formulation of the problem is presented showing how prices of energy and reserve services are obtained through the integration process.

The paper is organized as follows. Section III presents the formulation of the combined energy and reserve market including operational constraints imposed by the forward physical bilateral contracts and reserve services. Section IV describes the pricing mechanism. Section V illustrates the procedure for obtaining revenues and payments. Section VI describes the procedure for obtaining generators and loads portfolios. Section VII shows the reconciliation of costs. Section VIII gives numerical examples and Section V presents conclusions.

II. NOMENCLATURE

For each generator i and demand j participating in the integrated market, we define the following notation.

Generators Bid Parameters in (\$/h):

$C_{gi}^p(p_{gi}^p)$	Pool energy bid cost component.
$C_{gi}^{RU}(ru_{gi})$	Regulation up reserve bid cost component.
$C_{gi}^{RD}(rd_{gi})$	Regulation down reserve bid cost component.
$C_{gi}^{SR}(sr_{gi})$	Spinning reserve bid cost component.
$C_{gi}^{NS}(ns_{gi})$	Nonspinning reserve bid cost component.
$C_{gi}^{RC}(rc_{gi})$	Complementary reserve bid cost component.

Variables:

p_{gi}^p	Pool active generation awarded level (MW).
ru_{gi}	Awarded level of regulation up reserve (MW).
rd_{gi}	Awarded level of regulation down reserve (MW).
sr_{gi}	Awarded level of spinning reserve (MW).
ns_{gi}	Awarded level of nonspinning reserve (MW).
rc_{gi}	Awarded level of complementary reserve (MW).
q_{gi}	Reactive power generation level (Mvar).
v_i, δ_i	Module and angle of Bus i voltage phasor.
p_{ij}	Active power flow in transmission line connecting bus i and bus j .

Constant Parameters:

p_{gi}^b	Bilateral active power generation level at bus i (MW).
$p_{gi}^{\min}, p_{gi}^{\max}$	Active power capacity limits of generator i .
$q_{gi}^{\min}, q_{gi}^{\max}$	Reactive power capacity limits of generator i .
p_{ij}^{\max}	Maximum transmission capacity limit of transmission line connecting bus i and bus j .
v_i^{\min}, v_i^{\max}	Voltage limits at bus i .
p_{dj}	Pool active power demand level at bus j (MW).
$ru_i^{\max}, sr_i^{\max}, ns_i^{\max}, rd_i^{\max}$	Maximum capacity limit of bid parameter for reg-up, spinning, nonspinning, complementary, and reg-down.
p_{dj}^b	Bilateral active power demand level at bus j (MW).
q_{dj}	Reactive power demand level at bus j (Mvar).
R^{RU}	Amount of regulation up reserve required by the system (MW).

R^{RD}	Amount of regulation down reserve required by the system (MW).
R^{SR}	Amount of spinning reserve required by the system (MW).
R^{NS}	Amount of nonspinning reserve required by the system (MW).
R^{RC}	Amount of complementary reserve required by the system (MW).
N	Number of integration steps.
RP_{gi}^{RU}	The 10-min ramp rate for providing ru_{gi} in MW/min.
RP_{gi}^{SNS}	The 10-min ramp rate for providing sr_{gi} and ns_{gi} in MW/min.

III. FORMULATION

In this section is presented the formulation of the combined market of energy (with pool and bilateral contracts) and reserve services while in Section IV is presented the pricing model based on a PAB approach. In order to simplify the presentation, we consider that the demand has no participation in the ancillary service market by submitting curtailment bids in a load management program. Nevertheless, this extension can be easily incorporated as presented in [2]. Also, we consider a one hour auction with no inter-temporal constraints.

A. Pool and Reserve Auction

The combined Pool and reserve auction determine awarded energy and reserve bids for a period of one hour. In this market a merit order list based in low bid costs is obtained for energy and reserve services by minimizing the following objective function.

$$\text{Minimize } C_{\text{energy}} + C_{\text{reserve}}.$$

where

$$C_{\text{energy}} = \sum_i C_i(p_{gi}^p)$$

$$C_{\text{reserve}} = \left\{ \sum_i C_i^{RU}(ru_{gi}) + \sum_i C_i^{SR}(sr_{gi}) + \sum_i C_i^{NS}(ns_{gi}) + \sum_i C_i^{RC}(rc_{gi}) + \sum_i C_i^{RD}(rd_{gi}) \right\}. \quad (1)$$

Cost bid¹ functions can be considered as continuous quadratic or piece-wise linear functions.

B. Transmission Network

From the ISO point of view, awarded bids and firm bilateral contracts must observe operation constraints imposed by the transmission system. Therefore, feasible solutions should belong to the set defined by constraints (2)–(7) for all buses i in the transmission system. Long-term physical bilateral contracts and the pool demand are known quantities. Each demand j is considered to have two energy components $p_{dj} = p_{dj}^p + p_{dj}^b$,

¹Under pay-as-bid, generators bid above their true cost. In this paper, generator cost is understood to mean bid cost.

and the generator at bus i also has two energy components $p_{gi} = p_{gi}^p + p_{gi}^b$. The network load flow equations are represented by (2) and (3). Constraints (4) force the transmission lines active power flow to operate within limits (thermal or stability limits), constraints (5) define the operation range of generators, constraints (6) define the capacity limit of generators for supplying reactive power and constraints (7) represent the range of variation allowed for bus voltages. Vector V represents bus voltage modules and vector δ represents bus voltage phase angles. Both vectors have dimension equal to the total number of buses n

$$p_{gi} - p_{di} = p_i(V, \delta), \quad \rightarrow \lambda_i \quad (2)$$

$$q_{gi} - q_{di} = q_i(v, \delta), \quad (3)$$

$$p_{gi}^{\min} \leq p_{gi} \leq p_{gi}^{\max} \quad (4)$$

$$-p_{ij}^{\max} \leq p_{ij} \leq p_{ij}^{\max} \quad (5)$$

$$q_{gi}^{\min} \leq q_{gi} \leq q_{gi}^{\max} \quad (6)$$

$$v_i^{\min} \leq v_i \leq v_i^{\max}. \quad (7)$$

The set defined by (2)–(7) defines the security region of the power system in the space of generation levels. It is assumed in this model that the market for voltage support is obtained by specific agreements between regulator and suppliers, which is not part of the optimization model. Lambdas in (2) are Lagrange multipliers associated with each constraint and represent nodal prices for active power.

C. Reserve Market Characteristics

Generators agents can bid in five kinds of reserve services: regulation up, regulation down, spinning, nonspinning, and replacement. As mentioned in the introduction, the speed response defines the quality of each service, i.e., faster response reserves are graded as higher quality or higher value. In order to open possibilities for reducing costs, it is also permitted the possibility of substitution among reserve services. The substitution consists in allowing services with better quality and lower cost to replace services with lower quality and higher cost [1], [15]. Hence, a feasible bid selection in the reserve market auction, which also avoids price reversal between reserve services, should belong to the set described by the following constraints:

$$R^{RU} \leq \sum_{i=1}^n ru_{gi} \quad \rightarrow \lambda^{RU} \quad (8)$$

$$R^{RU} + R^{SR} \leq \sum_{i=1}^n ru_{gi} + \sum_{i=1}^n sr_{gi} \rightarrow \lambda^{SR} \quad (9)$$

$$R^{RU} + R^{SR} + R^{NS} \leq \sum_{i=1}^n ru_{gi} + \sum_{i=1}^n sr_{gi} + \sum_{i=1}^n ns_{gi} \rightarrow \lambda^{NS} \quad (10)$$

$$R^{RC} \leq \sum_{i=1}^n rc_{gi} \rightarrow \lambda^{RC} \quad (11)$$

$$R^{RD} \leq \sum_{i=1}^n rd_{gi} \rightarrow \lambda^{RD} \quad (12)$$

$$ru_{gi} \geq 0, \quad sr_{gi} \geq 0, \quad ns_{gi} \geq 0$$

$$rc_{gi} \geq 0, \quad rd_{gi} \geq 0 \quad (13)$$

$$ru_{gi} \leq ru_i^{\max}, \quad sr_{gi} \leq sr_i^{\max},$$

$$ns_{gi} \leq ns_i^{\max}$$

$$rc_{gi} \leq rc_i^{\max}, \quad rd_{gi} \leq rd_i^{\max}. \quad (14)$$

where R^{RU} , R^{SR} , R^{NS} , R^{RC} , and R^{RD} (in MW) are the estimated required system amounts of each reserve service during a one hour period. These quantities are considered known and defined by the ISO before the market auction occurs. Lambda variables are Lagrange multipliers associated with each constraint. Upper limits in (14) are physical limits associated to generators ramp rates and they are part of the information of the reserve bids.

D. Long-Term Bilateral Contracts

Private long-term bilateral contracts are considered as firm physical (not financial) contracts which are authorized and implemented by the ISO who takes into consideration the security conditions of the transmission network. In a compact form, bilateral contracts can be grouped in a GD matrix where each coefficient GD_{ij} represents the MW traded between generator at bus i and load at bus j . Therefore, the total amount of contracts supplied by generator i is

$$p_{gi}^b = \sum_{j=1}^n GD_{ij}. \quad (15)$$

In addition, the total amount of contracts supplying the demand at bus j is

$$p_{dj}^b = \sum_{i=1}^n GD_{ij}. \quad (16)$$

In this model is supposed that firm long-term bilateral contracts are already in place at the moment of performing one auction and they have priority in relation to the pool dispatch in terms of allocating generation capacity [4]. Because of this, the already committed capacity to bilateral contracts imposes a constraint on the lower generation limit for generators participating in the pool market as shown in the following:

$$p_{gi}^b \leq p_{gi} \leq p_{gi}^{\max}. \quad (17)$$

E. Reserve Availability of Generators Capacity

In the combined market, besides meeting bilateral and pool loads, each generator i can also participate in the reserve market by bidding several reserve services. The awarded reserve bids should respect the operational capacity limits of each generator as described in the following:

$$p_{gi} + ru_{gi} + sr_{gi} + ns_{gi} \leq p_{gi}^{\max} \quad (18)$$

$$-rd_{gi} + p_{gi} \geq p_{gi}^b. \quad (19)$$

It is worth noting that because of the substitution, if the system in a particular scenario cleared its needs for up regulation and spinning reserve on the basis of lower bid prices and it is still looking for meeting nonspinning reserve requirements, then the optimization not only considers the nonspinning bid costs but also considers lower price bids of spinning still available. Therefore, a particular spinning reserve bid can be accepted on the basis of lower cost for supplying the nonspinning requirement. In case there is no possibility of substitution because of the operation conditions, the generators only bidding for nonspinning reserve have their generation, regulation up and spinning levels at zero in constraint (18).

An important consideration is the capacity of response due to the technology adopted by each generator i characterized by

the corresponding ramp rate in MW/min. As suggested in [1], the following shows how to consider this constraint on a 10-min basis of time through a linear relationship:

$$\frac{ru_{gi}}{RP_{gi}^{RU}} + \frac{rs_{gi} + ns_{gi}}{RP_{gi}^{SNS}} - 10 \leq 0. \quad (20)$$

F. Marginal Price of Reserve Services

The Lagrangean function of the optimization problem described in (1) to (20) allows to obtain expressions for the market clearing prices of services based on the Lagrange multipliers. These prices represent the sensitivity of cost in terms of incremental perturbations of reserve requirements as shown in the following:

$$\frac{\partial L}{\partial R^{RU}} = \lambda^{RU} + \lambda^{SR} + \lambda^{NS} = MCP_{RU} \quad (21)$$

$$\frac{\partial L}{\partial R^{SR}} = \lambda^{SR} + \lambda^{NS} = MCP_{SR} \quad (22)$$

$$\frac{\partial L}{\partial R^{NS}} = \lambda^{NS} = MCP_{NS} \quad (23)$$

$$\frac{\partial L}{\partial R^{RC}} = \lambda^{RC} = MCP_{RC} \quad (24)$$

$$\frac{\partial L}{\partial R^{RD}} = \lambda^{RD} = MCP_{RD}. \quad (25)$$

Since Lagrange multipliers are positive, this formulation avoids reversal prices among services. In other words, $MCP_{RU} \geq MCP_{SR} \geq MCP_{NS}$ as discussed in [1] and [6].

IV. PAY-AS-BID PRICING MODEL

The pay-as-bid version of this model is implemented through an integration process based on the Aumann-Shapley technique [3] that takes into consideration the nonlinear characteristic existing in the transmission network due to capacity limits, transmission losses and voltage behaviors. These features are not present in simpler pay-as-bid schemes such as *pro-rata*. The integration process allows unbundling the use and prices of several services including pool dispatch, reserve capacity and bilateral contracts. One-iteration of the process is described as follows.

Step 1) *Bilateral Contracts Losses and Congestion*: In this step, losses attributed to bilateral contracts due to the use of the transmission network are compensated in the Pool market. Initially, the bilateral load is incremented by dGD_{ij} while holding fixed the pool load and reserve requirements whose value at the very beginning are nil. In this step, the optimization problem minimizes costs of loss compensation due to bilateral contracts and possible congestion management. The incremental optimization problem to be solved is defined by (1)–(20) considering for each load j an incremental variation $dp_{dj}^b = \sum_i dGD_{ij}$ while holding fixed pool loads p_{dj}^p and reserve requirements R^{RU} , R^{SR} , R^{NS} , R^{RC} , R^{RD} . Calling the solution of this problem as dp_{gi}^* , the contract incremental losses and congestion management are obtained through the following:

$$dp_{gi}^{bpcl} = dp_{gi}^* - \sum_{j=1}^n dGD_{ij}. \quad (26)$$

Step 2) *Pool and Reserve Market*: In this step, the incremental optimization problem to be solved is defined by (1)–(20) incrementing pool loads j by dp_{dj}^p . Reserve requirements are incremented consecutively by dR^{RU} , dR^{SR} , dR^{NS} , dR^{RC} , dR^{RD} while holding fixed the bilateral contract loads. The solution of this optimization problem gives the awarded pool generation levels, dp_{gi}^p , and incremental reserve levels, dr_{ugi} , dsr_{gi} , dns_{gi} , drc_{gi} and drc_{gi} .

1) *Integration Process*: The integration process consists in performing alternatively step 1 and step 2 for small load increments following a uniform integration path from zero to the final value of the load, according to the “ t ” parameter such that $0 \leq t \leq 1$, as shown in the following:

$$X = \int_{t=0}^1 dx(t) \quad (27)$$

where vector dx is composed of variables dp_{gi}^b , dp_{gi}^p , dp_{gi}^{bpc} , dr_{ugi} , dsr_{gi} , dns_{gi} , drc_{gi} and drc_{gi} . The integration process of each load and required service follows the adjustment of parameters indicated in the following, where GD is the contract matrix and p_d^p is the vector of pool loads. Other reserve services follow the same incremental procedure

$$GD(t^b) = t^b \cdot GD, \quad 0 \leq t^b \leq 1 \quad (28)$$

$$P_d^p(t^p) = t^p \cdot P_d^p, \quad 0 \leq t^p \leq 1 \quad (29)$$

$$R^{RU}(t^{RU}) = t^{RU} \cdot R^{RU}, \quad 0 \leq t^{RU} \leq 1. \quad (30)$$

The integration parameters $t = \{t^b, t^p, t^{RU}, t^{SR}, t^{NS}, t^{RD}\}$ are zeroed before starting the integration process i.e., $t^{(0)} = \{0, 0, 0, 0, 0, 0\}$. A constant incremental step $dt = t/N$ is added consecutively during the integration process as showed in the following for the first increment and the first three parameters. The other incremental reserve requirements are added in the same way

$$t^{(1)} = \{dt^b, 0, 0, 0, 0, 0\} \quad (31)$$

$$t^{(1)} = \{dt^b, dt^p, 0, 0, 0, 0\} \quad (32)$$

$$t^{(1)} = \{dt^b, dt^p, dt^{RU}, 0, 0, 0\}. \quad (33)$$

In subsequent integration steps additional dt increments are added to the previous ones in the same order.

V. REVENUES AND PAYMENTS

This section presents how revenues and payments are calculated for generators and loads participating in the combined market. Economic indexes are presented incrementally. Their corresponding final values are obtained by completing the integration process previously described.

1) *Bilateral Contracts*: Because bilateral contracts are negotiated in private, their prices are not available. Nevertheless, we adopt as a price for these contracts the corresponding incremental costs of generators i.e., $IC_{gi}^b = dC_{gi}^b(P_{gi}^b)/dP_{gi}^b$.

Revenues: The revenue of generator i due to bilateral contracts is

$$dc_{gi}^b = IC_{gi}^b \cdot \sum_{j=1}^n dGD_{ij}. \quad (34)$$

Payments: Load j pays the supplied bilateral contracts according to the following:

$$dc_{dj}^b = \sum_{i=1}^n IC_i^b \cdot dGD_{ij}. \quad (35)$$

Bilateral contracts should pay for losses and congestion management according to the following:

$$dc_{ij}^{bcl} = \sum_{i=1}^n (\lambda_j - \lambda_i) \cdot dGD_{ij}. \quad (36)$$

This amount could be split among contract parties in a 50/50 basis or other proportion; we adopt a split of 50/50. The corresponding payment of generator i for all its bilateral contracts losses and congestion is

$$dc_{gi}^{bcl} = \left(\frac{1}{2}\right) \sum_{j=1}^n dc_{ij}^{bcl}. \quad (37)$$

Similarly, the payment of the bilateral load j is

$$dc_{dj}^{bcl} = \left(\frac{1}{2}\right) \sum_{i=1}^n dc_{ij}^{bcl}. \quad (38)$$

2) *Pool and Reserve*:

Revenues: Generator i has revenues for supplying pool demand, bilateral loss compensation and congestion management as well as providing reserve capacity as shown in the following:

$$d\hat{c}_{gi}^p = \lambda_i \cdot dp_{gi}^p \quad (39)$$

$$dc_{gi}^{bpc} = \lambda_i \cdot dp_{gi}^{bpc} \quad (40)$$

$$dc_{gi}^{RU} = MCP_{RU} \cdot dr_{ugi} \quad (41)$$

$$dc_{gi}^{SR} = MCP_{SR} \cdot dsr_{gi}. \quad (41)$$

Incremental revenues obtained from other reserve services follow similar calculations.

Payments: Load j has payments related to the use of pool demand including losses, and reserve services according to the following. In the case of reserve services, load j pays in a *pro-rata* manner as shown in (43) and (44)

$$d\hat{c}_{dj}^p = \lambda_j dp_{dj}^p \quad (42)$$

$$dc_{dj}^{SR} = \frac{MCP_{SR} \cdot \left(\sum_{i=1}^n dsr_{gi}\right) \cdot (p_{dj}^p + p_{dj}^b)}{Pd_{Total}} \quad (43)$$

$$dc_{dj}^{RU} = \frac{MCP_{RU} \cdot \left(\sum_{i=1}^n dr_{ugi}\right) \cdot (p_{dj}^p + p_{dj}^b)}{Pd_{Total}} \quad (44)$$

where Pd_{Total} is the total system load including bilateral and pool demand. Incremental load payments related to the other services are obtained in a similar way.

VI. GENERATORS AND LOADS PORTFOLIOS

At the end of the integration process the portfolio revenue of generator i is obtained by using (27). This portfolio is composed basically by three terms corresponding to bilateral, pool and reserve markets as follows:

$$c_{gi} = c_{gi}^b + c_{gi}^p + c_{gi}^R \quad (45)$$

where

$$c_{gi}^R = c_{gi}^{RU} + c_{gi}^{RD} + c_{gi}^{SR} + c_{gi}^{NS} + c_{gi}^{RC} \quad (46)$$

$$c_{gi}^p = \hat{c}_{gi}^p + c_{gi}^{bpcl} - c_{gi}^{bcl}. \quad (47)$$

Likewise, the portfolio payment of load j is composed by three terms corresponding to bilateral, pool and reserve markets as follows:

$$c_{dj} = c_{dj}^b + c_{dj}^p + c_{dj}^R \quad (48)$$

where

$$c_{dj}^R = c_{dj}^{RU} + c_{dj}^{RD} + c_{dj}^{SR} + c_{dj}^{NS} + c_{dj}^{RC} \quad (49)$$

$$c_{dj}^p = \hat{c}_{dj}^p + c_{dj}^{bcl}. \quad (50)$$

VII. RECONCILIATION OF COSTS

Under the pay-as-bid scheme, the costs allocated to the loads and bilateral contracts perfectly match the generation cost components as demonstrated in [5]. This characteristic is also demonstrated when considering the reserve market at the end of the integration process. Hence, for the supply of pool demand and associated loss and congestion management, we have

$$\sum_{i=1}^n c_{gi}^p = \sum_{j=1}^n c_{dj}^p. \quad (51)$$

In particular, for services received from bilateral contracts due to losses and congestion management, we have

$$\sum_{i=1}^n c_{gi}^{bpcl} = \sum_{i=1}^n \sum_{j=1}^n c_{ij}^{bcl}. \quad (52)$$

For supplying bilateral contracts, we have

$$\sum_{i=1}^n c_{gi}^b = \sum_{j=1}^n c_{dj}^b. \quad (53)$$

Additionally, there is also reconciliation of costs for reserve services. For instance, in the case of the spinning reserve, we have

$$\sum_{i=1}^n c_{gi}^{SR} = \sum_{j=1}^n c_{dj}^{SR}. \quad (54)$$

TABLE I

GENERATORS ENERGY BIDS $C_{gi}(p_{gi}) = c_{0i} + a_i \cdot p_{gi} + 0.5 \cdot b_i \cdot p_{gi}^2$ (\$/h)

Bus	p_g^{\min} (MW)	p_g^{\max} (MW)	c_0 (\$/h)	a (\$/MW ² h)	b (\$/MW ² h)
1	0	170	0	20	0.040
2	0	40	0	21	0.030
3	0	80	0	25	0.045
6	0	100	0	56	0.040
8	0	100	0	57	0.040

TABLE II

BILATERAL CONTRACTS GD MATRIX(MW)

Bus	Generators (MW)						
	1	2	3	6	8	Total	
2	18.0	0	0	0	0	18	
3	86.0	0	0	0	0	86	
4	42.0	0	0	0	0	42	
5	3.0	0	0	0	0	3	
6	0	10.0	0	0	0	10.0	
9	0	29.0	0	0	0	29.0	
10	0	0	9.0	0	0	9.0	
11	0	0	3.0	0	0	3.0	
12	0	0	6.0	0	0	6.0	
13	0	0	13.5	0	0	13.5	
14	0	0	14.5	0	0	14.5	
Total	149	39	46	0	0	234	

This equivalence can be easily proved by using (44) and (41) in the integration process (see the Appendix).

VIII. NUMERICAL RESULTS

This section analyzes results considering the IEEE 14-bus network [20]. The only modification of the original system consists in connecting generators at buses 3, 6, and 8. The network data are in per unit in a base of 100 MVA and 200 kV. Table I describes generator bid costs with capacity limits and bid parameters, c_{gi} , representing continuous functions. The only two reserve services required by the system are $R^{RU} = 2.95$ MW and $R^{SR} = 10$ MW corresponding to a reserve margin of 5% of total load (i.e., 13 MW). In order to simplify the amount of data, the generators bid parameters for regulation up reserve service are considered half of the corresponding energy bids in Table I (i.e., $a_{g1}^{RU} = 10$ \$/MW²h and $b_{g1}^{RU} = 0.02$ \$/MW²h for the generator 1 reserve bid and similar for the other generators in terms of regulation up reserve bids). Spinning reserve bids for all generators are considered more expensive and equal to the corresponding energy bids.

The total fixed system load of 259 MW is distributed among buses according with the following vector: $p_d = [0, 21.7, 94.2, 47.8, 7.6, 11.2, 0, 0, 29.5, 9.0, 3.5, 6.1, 13.5, 14.9]^T$ (MW). This load can be supplied by bilateral and pool markets in different proportions or distributions of bilateral contracts. Table II shows bilateral contracts matrix, GD. When the full amounts of contracts in GD matrix are implemented they represent 90% of the total system load. In this case, the pool loads required at each bus are the coefficients of vector $p_d^p = [0, 3.7, 8.2, 5.8, 4.6, 1.2, 0, 0, 0.5, 0.1, 0, 0.4]^T$ (MW). Bilateral tariffs are chosen as, $\pi_{ij}^b = dC_{gi}(P_{gi}^b)/dP_{gi}$ for bilateral loads j .

The first example corresponds to a situation when the system is operating without transmission congestion, ramp constraints

TABLE III
ENERGY AND RESERVE MARKET DISPATCH THROUGH THE INTEGRATED PAB APPROACH. BILATERAL CONTRACTS PARTICIPATION EQUAL TO 90% OF TOTAL LOAD. POWER IN MW, λ , π_g^b AND AVERAGE COSTS IN \$/MWH. ROWS WITH * CONTAIN GIVEN DATA

Bus	1	2	3	6	8	Total
P_g^b	149.0	39.0	46.0	0.0	0.0	234.0
P_g^p	6.6	1.0	23.9	0.0	0.0	31.5
P_g	155.6	40.0	69.9	0.0	0.0	265.5
ru_g	13.0	0.0	0.0	0.0	0.0	13.0
sr_g	0.0	0.0	0.0	0.0	0.0	0.0
Total R	13.0	0.0	0.0	0.0	0.0	13.0
* P_d^b	0.0	18.0	86.0	10.0	0.0	234.0
* P_d^p	0.0	3.7	8.2	1.2	0.0	25.0
* P_d	0.0	21.7	94.2	11.2	0.0	259.0
λ	26.2	27.3	28.1	28.2	28.5	-
IC_g	26.2	22.2	28.1	56.0	57.0	-
* π_g^b	26.0	22.2	27.1	56.0	57.0	-
C_g^b/P_g^b	23.0	21.6	26.0	-	-	-
C_g^p/P_g^p	26.1	22.2	27.6	-	-	-
C_g^{RU}/ru_g	10.1	-	-	-	-	-

TABLE IV
GENERATORS REVENUE PORTFOLIO (\$/H)

Bus	Energy		Reserve	Total
	C_g^b	C_g^p	C_g^R	
1	3424.0	172.9	131.2	3728.1
2	841.8	22.2	0.0	864.0
3	1197.6	659.2	0.0	1856.8
6 and 8	0.0	0.0	0.0	0.0
Total	5463.4	854.3	131.2	6448.9

limits are relaxed and there is enough reactive support to keep bus voltages within limits. Table III shows in rows 1 to 6 the combined market dispatch supplying total load and transmission losses of 6.5 MW. As can be seen, the more economical operation forces the cheap generator 1 to participate in the three markets. The lower cost of regulation up reserve bids of generator 1 is awarded with 13.0 MW for supplying the total reserve requirement. Rows 7 to 9 show some given data about the load distribution and total load components. The last six rows of the table show economic indexes such as incremental costs and prices of services of the three markets. Incremental costs are about the same for the three generators participating in the joint market with small differences due to transmission losses. Due to the fact that bilateral contracts only exist for the more economical generators, their average bilateral prices are lower than their corresponding incremental costs. Average prices for energy are lower than marginal prices with average prices for reserve being slightly lower than the corresponding marginal clearing price, MCP_{ru} , which is equal to 10.3 \$/MWh. Tables IV and V show the agents participation in the three markets indicating generators revenue and loads payment components. As a result of the

TABLE V
LOADS PAYMENT PORTFOLIO (\$/H)

Bus	Energy		Reserve	Total
	C_d^b	C_d^p	C_d^R	
2	420.3	71.6	11.0	502.8
3	2007.9	310.7	47.7	2366.3
4	980.6	157.7	24.2	1162.5
5	70.0	25.1	3.8	99.0
6	233.5	36.9	5.7	276.1
9	677.1	97.3	14.9	789.3
10	210.1	29.7	4.6	244.4
11	70.0	11.5	1.8	83.4
12	140.1	20.1	3.1	163.3
13	315.2	44.5	6.8	366.6
14	338.5	49.1	7.5	395.2
Total	5463.4	854.3	131.2	6448.9

TABLE VI
ENERGY AND RESERVE MARKET DISPATCH THROUGH THE INTEGRATED PAB APPROACH. BILATERAL CONTRACTS PARTICIPATION EQUAL TO 90% OF TOTAL LOAD. GENERATOR 1 WITH REDUCED CAPACITY. POWER IN MW, λ , π_g^b AND AVERAGE COSTS IN \$/MWH. ROWS WITH * CONTAIN GIVEN DATA

Bus	1	2	3	6	8	Total
P_g^b	149.0	39.0	46.0	0.0	0.0	234.0
P_g^p	0.0	1.0	30.1	0.0	0.0	31.1
P_g	149.0	40.0	76.1	0.0	0.0	265.1
ru_g	1.0	0.0	3.9	8.0	0.0	13.0
sr_g	0.0	0.0	0.0	0.0	0.0	0.0
Total R	1.0	0.0	3.9	8.0	0.0	13.0
* P_d^b	0.0	18.0	86.0	10.0	0.0	234.0
* P_d	0.0	3.7	8.2	1.2	0.0	25.0
* P_d^{Total}	0.0	21.7	94.2	11.2	0.0	259.0
λ	41.4	42.8	44.0	44.3	44.7	-
IC_g	26.0	22.2	28.4	56.0	57.0	-
* π_g^b	26.0	22.2	27.1	56.0	57.0	-
C_g^b/P_g^b	23.0	21.6	26.0	0.0	0.0	-
C_g^p/P_g^p	0.0	22.2	27.7	0.0	0.0	-
C_g^{RU}/ru_g	10.0	-	12.5	28.1	-	-

lower bid, generator at bus 1 is the only one to obtain revenues from the three market products. The reconciliation of revenues and payments for energy (bilateral and pool) and reserve can be observed by comparing the last rows of both tables which are identical and consequently no merchandising surplus (MS) is produced. If the same generator bids are used in a marginal pricing approach, the total cost of operation is 7271.5 \$/h which represents an increase of 12.7% in relation to the total cost of 6448.9 \$/h obtained by the PAB approach.

The second example has only one change with respect to the previous example. The modification consists in reducing the total capacity of generator 1 to only 150 MW (this situation can be interpreted as an strategy of withholding capacity or contingency in one of its units). The first six rows in Table VI describe the new dispatch in the energy and reserve markets.

TABLE VII
GENERATORS REVENUE PORTFOLIO (\$/H)

Bus	Energy		Reserve	Total
	C_g^b	C_g^p	C_g^R	
1	3424.0	0.0	10.0	3434.0
2	841.8	22.2	0.0	864.0
3	1197.6	835.2	48.9	2081.7
6	0.0	0.0	226.0	226.0
8	0.0	0.0	0.0	0.0
Total	5463.4	857.4	285.0	6605.8

TABLE VIII
LOADS PAYMENT PORTFOLIO (\$/H)

Bus	Energy		Reserve	Total
	C_d^b	C_d^p	C_d^R	
2	420.3	71.8	23.9	516.0
3	2007.9	311.8	103.6	2423.4
4	980.6	158.2	52.6	1191.4
5	70.0	25.2	8.4	103.6
6	233.5	37.1	12.3	282.9
9	677.1	97.7	32.5	807.2
10	210.1	29.8	9.9	249.8
11	70.0	11.6	3.9	85.5
12	140.1	20.2	6.7	167.0
13	315.2	44.7	14.9	374.7
14	338.5	49.3	16.4	404.3
Total	5463.4	857.4	285.0	6605.8

Because of the high bilateral commitments of generators 1 and 2, almost all the pool market and losses are supplied by generator at bus 3 which is more expensive. Similar situation happens with the allocation of reserve which is mainly supplied by the more expensive generators at buses 3 and 6. Rows 10 to 15 allow comparing marginal prices and average prices. Marginal prices at buses where generators are connected jump to almost twice the value obtained in the previous case while average prices obtained by the PAB model do not change significantly. In the reserve market, average prices increase reflecting the use of more expensive generators to supply the system reserve requirement. The marginal price for reserve is 28.2 \$/MWh and the total cost of operation is 11 596.7 \$/h which is almost twice the cost obtained by the PAB model. Tables VII and VIII show the revenues and payments portfolios composition as well as the corresponding financial adequacy. Comparing with the previous case, the total revenue of generator at bus 1 decreases and the revenues of generators at buses 3 and 6 increase. All loads payments increase and total load payment increases 2.4%. In the marginal approach total payment has an increase of 60%.

Other results obtained by increasing the total reserve requirement in both of the previous cases show that average prices and marginal prices increase but always average prices stay lower than marginal prices (assuming that in both approaches they submit the same bids). We also observed that in cases where generators submit low bid for other reserve services like spinning reserve, they are awarded for attending the system requirements following substitution constraints (8)–(14).

Tables IX and X show a comparison of the PAB model with the model presented in [1] which uses a marginal approach (called MP in the table). Results correspond to the first numerical example without the presence of bilateral contracts

TABLE IX
GENERATORS REVENUE PORTFOLIO (\$/H) COMPARISON BETWEEN THE INTEGRATED PAY-AS-BID MODEL AND THE MP MODEL (WITHOUT BILATERAL CONTRACTS)

Bus	Energy			Reserve		
	C_g^p (\$/h)			C_g^R (\$/h)		
	PAB	MP	$\Delta(\%)$	PAB	MP	$\Delta(\%)$
1	3243.1	3777.3	16.5	130.9	138.4	5.7
2	864.0	1113.5	28.9	0.0	0.0	0.0
3	2200.1	2313.5	5.2	0.0	0.0	0.0
6 and 8	0.0	0.0	0.0	0.0	0.0	0.0
Total	6307.1	7204.2	14.2	130.9	138.4	5.7

TABLE X
LOADS PAYMENT PORTFOLIO (\$/H) COMPARISON BETWEEN THE INTEGRATED PAY-AS-BID MODEL AND THE MP MODEL (WITHOUT CONTRACTS)

Bus	Energy			Reserve		
	C_d^p			C_d^R		
	PAB	MP	$\Delta(\%)$	PAB	MP	$\Delta(\%)$
2	528.4	604.1	14.3	11.0	11.6	5.5
3	2293.9	2659.1	15.9	47.6	50.4	5.9
4	1164.0	1329.1	14.2	24.1	25.5	5.8
5	185.1	208.3	12.5	3.8	4.1	7.9
6	272.7	321.3	17.8	5.7	6.0	5.3
9	718.4	847.3	17.9	14.9	15.7	5.4
10	219.2	261.8	19.4	4.5	4.8	6.7
11	85.2	103.3	21.2	1.8	1.9	5.6
12	148.5	185.5	24.9	3.1	3.3	6.5
13	328.8	411.2	25.1	6.8	7.2	5.9
14	362.8	450.3	24.1	7.5	7.9	5.3
Total	6307.1	7381.1	17.0	130.9	138.4	5.7

since the model in [1] does not incorporate them. Total load of 249 MW is only supplied by the pool energy market. Results show bigger generators revenues in the marginal approach for energy and reserve (considering they submit the same bids in both approaches). Loads have to pay more in the marginal approach than in the PAB approach for energy and reserve (positive percentage variations in the table indicate increased payments by using the MP model). Moreover, as can be seen in the last rows of both tables, there is financial reconciliation by the PAB model in the energy and reserve markets, but this characteristic is not present in the MP model.

Table XI shows results about the impact of ramp limits on the dispatch considering the same market conditions of the first numerical example. As can be observed, there is a different allocation of reserve capacity. This is because the cheaper generator at bus 1 has a restrictive ramp limit of 5 MW/h preventing this generator to fully supply the system reserve requirement of 13 MW. Since the capacity of generator 2 (with the second lower bid cost) is already committed satisfying the energy market, the generator at bus 3 (with the third lower bid cost) supplies the remaining 7.9 MW of capacity required by the system. This new solution increases the total cost of operation as can be seen in Tables XII and XIII.

A final numerical simulation is presented for observing the PAB model when there is a constrained operation of the system. In this case, it is considered the same market situation of the first example, but the transmission capacity and the reactive supply

TABLE XI
ENERGY AND RESERVE MARKET DISPATCH CONSIDERING RAMP LIMITS AND THE INTEGRATED PAB MODEL. BILATERAL CONTRACTS PARTICIPATION EQUAL TO 90% OF TOTAL LOAD. POWER IN MW

Bus	1	2	3	6	8	Total
P_g^b	149.0	39.0	46.0	0.0	0.0	234.0
P_g^p	4.8	1.0	24.8	0.0	0.0	30.6
P_g	153.8	40.0	70.8	0.0	0.0	264.6
ru_g	5.0	0.0	7.9	0.0	0.0	12.9
sr_g	0.0	0.0	0.0	0.0	0.0	-0.0
Total R	5.0	0.0	7.9	0.0	0.0	12.9

TABLE XII
GENERATORS REVENUE PORTFOLIO (\$/H) THROUGH THE INTEGRATED PAY-AS-BID MODEL CONSIDERING THREE CASES

Bus	Energy			Reserve		
	C_g^P			C_g^R		
	Norma 1	Ramp	V, Q and LT	Norma 1	Ramp	V, Q and LT
1	122.6	125.6	138.6	130.8	50.2	131.0
2	22.2	22.2	22.2	0.0	0.0	0.0
3	686.1	685.0	696.3	0.0	99.5	0.0
6 and 8	0.0	0.0	0.0	0.0	0.0	0.0
Total	830.9	832.7	857.2	130.8	149.8	131.0

capacity of generators are reduced simultaneously. As a result, the flow in transmission line 1–2 reaches its maximum capacity limit of 100 MW, generators at buses 2, 3, 6 and 8 produce reactive power at their maximum capacity limit and all bus voltages operate in the range of 0.95 and 1.05 pu (some of them at their limits). Tables XII and XIII show the comparison of revenues and payments considering the pool energy and reserve markets for three situations: normal (first numerical example), considering ramp limits and considering restrictive transmission, voltage and reactive limits. The comparison of numbers in the columns of these tables shows differences due to the different active operational constraints. In all conditions and in both markets the financial adequacy is verified. Taking as a reference the normal case and observing revenues and payments, the tendency is that the Pool energy market is more sensitive to capacity limits of transmission, reactive power and voltages than the reserve market. On the other hand, reserve market is more sensitive to ramp limits than the pool energy market.

The previous numerical cases show that reserve prices are sensitive to the available capacity of generators which also depends on the committed capacity allocated to supply pool demand and the long-term bilateral contracts. This is an important economic signal for both energy and reserve markets that allow generators to be able to better estimating their opportunity cost. Additionally, economic indexes in the joint market reflect the impact of the transmission network and ramp limits. The pricing model allows obtaining revenue and payment portfolios with the important characteristic of financial adequacy. Results also show the load payment minimization through reasonable price stability by the PAB model in several operation scenarios.

TABLE XIII
LOADS PAYMENTS PORTFOLIO (\$/H) THROUGH THE INTEGRATED PAY-AS-BID MODEL CONSIDERING THREE CASES

Bus	Energy			Reserve		
	C_d^P			C_d^R		
	Norma 1	Ramp	V, Q and LT	Norma 1	Ramp	V, Q and LT
2	69.6	69.8	71.8	11.0	12.5	11.0
3	302.2	302.9	311.8	47.6	54.5	47.7
4	153.4	153.7	158.2	24.1	27.6	24.2
5	24.4	24.4	25.2	3.8	4.4	3.8
6	35.9	36.0	37.1	5.7	6.5	5.7
9	94.6	94.8	97.6	14.9	17.1	14.9
10	28.9	28.9	29.8	4.5	5.2	4.6
11	11.2	11.3	11.6	1.8	2.0	1.8
12	19.6	19.6	20.2	3.1	3.5	3.1
13	43.3	43.4	44.7	6.8	7.8	6.8
14	47.8	47.9	49.3	7.5	8.6	7.5
Total	830.9	832.7	857.2	130.8	149.8	131.0

Results clearly evidence the importance of a joint market of energy and services reflecting the operation condition of the transmission system.

IX. CONCLUSION

In this paper a new pricing model is presented with the following characteristics: 1) incorporation of bilateral, pool, and reserve markets in a joint market of services; 2) the combined market allows assessing the impact of interactions between electricity products on the operation and consequently on prices; 3) allows comparing the pay-as-bid pricing and marginal pricing approaches; 4) detailed portfolios are provided for agents in terms of revenues and payments in each market; 5) ensures the reconciliation between payments and revenues (or financial adequacy); 6) allows to obtain economic signals for estimating opportunity costs of electricity products; and 7) allows the possibility of testing several operating scenarios with bid strategies in order to evaluate the impact on agents portfolios.

The model considers the transmission system operation in detail including generation and transmission capacities, transmission losses, voltage limits and reactive limits. long-term bilateral contracts are modeled as physical firm contracts loading transmission lines and therefore producing transmission losses. Several reserve services are considered according with the quality of speed response. The possibility of substitution among these services is permitted for the purpose of cost reduction and the substitution avoids the undesirable price reversal.

The characteristics of this model make it attractive for analyzing the impact of several operation scenarios and bid strategies on agent’s portfolios. Further research is under development for studying in detail the presence of fault uncertainty, multi-period auctions and the model application on large power systems.

APPENDIX

Proof of Cost Reconciliation: From (45)

$$\sum_j dc_{dj}^{SR} = MCP_{SR} \cdot \left(\sum_{i=1}^n dsr_{gi} \right). \quad (55)$$

By using (42)

$$\sum_j dc_{dj}^{SR} = \sum_{i=1}^n MCP_{SR} \cdot dsr_{gi} = \sum_i dc_{gi}^{SR}. \quad (56)$$

Finally, by applying the integration process, (54) is obtained. The proof is similar for other reserve services.

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Fabio Stacke received the M.Sc. degree in electrical engineering from the Department of Electrical Engineering, University of Brasília, Brasília, Brazil. He is currently pursuing the D.Sc. degree in power systems economics and optimization.

He is working with the Brazilian Electricity Regulatory Agency—ANEEL in Brasília.

Pablo Cuervo (SM'03) received the M.S. and D.S. degrees from University of Campinas—UNICAMP, Campinas, Brazil.

He developed postdoctoral research activities at McGill University, Montreal, QC, Canada. He is currently a full Professor in the Department of Electrical Engineering of Brasília University, Brasília, Brazil. His current research activities are focused on power system planning and economics.