Research Article

Toward a New Nodal Pricing Policy of the Brazilian Transmission System Considering Multiple Hydrological Scenarios

Carlos R. R. Dornellas,1 Armando M. Leite da Silva,2 João G. C. Costa,1 Zulmar S. Machado Jr,1 André L. M. Marcato,3 and João C. O. Mello4

1Institute of Electric Systems and Energy, Federal University of Itajubá—UNIFEI, Itajubá, MG, Brazil
2Department of Electrical Engineering, Pontifical Catholic University of Rio de Janeiro—PUC-Rio, Rio de Janeiro, RJ, Brazil
3Department of Electrical Engineering, Federal University of Juiz de Fora—UFJF, Juiz de Fora, MG, Brazil
4Thymos Energia, São Paulo, SP, Brazil

Correspondence should be addressed to Armando M. Leite da Silva; armando@ele.puc-rio.br

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This paper presents a new method for allocating transmission system costs in hydro prevailing energy markets. The proposed approach is based on nodal pricing, and it considers multiple hydrological scenarios obtained from optimized energy models. These models are much closer to the operational reality of hydro dominant systems and more adequate to the transmission operation planning. The nodal pricing strategy comprises two steps to recover the total costs of the transmission system. The first one calculates the charges corresponding to the utilized network capacity, estimated at a specified operating condition, and it brings the locational signal to the tariff. In the second step, the charges related to the transmission capacity available but not used in the system are assessed by a postage stamp. This latter step accomplishes the task of recovering the total transmission charges and defining the final tariff for specific operating dispatching. On the other hand, the optimized energy models, based on stochastic dual dynamic programming, are used to minimize the operating costs while penalizing possible energy spillages. These models create monthly sequences of hydrothermal coordinated generating scenarios and dispatching conditions, which are used by the nodal pricing strategy to produce the generation/load charges and tariffs and the corresponding statistics. The proposed method, combining the nodal pricing strategy and the optimized energy model, is applied to a Brazilian network configuration and the results are fully discussed. Moreover, probabilistic analyses are also performed to describe the annual costs of transmission of thermoelectric and hydroelectric plants and industrial electrointensive consumers installed in different areas of the network.

1. Introduction

The transmission system plays a fundamental role in the functioning of an electricity market [1], and its pricing affects the revenues of concessionary companies and the costs of generating agents and consumers. Moreover, it is an important issue linked to market rules and regulation of electric power distribution systems [2]. Expenses related to the operation, maintenance, and investments in the expansion of the network must be divided among market participants according to prespecified criteria. The procedures for allocation of transmission costs can be divided into three groups [3]: methods that translate average behaviors, incremental approaches, and marginal methods.

In the first group, transmission costs are allocated among participant agents based on proportions of regulatory variables such as peak loads and transmitted energies. Such methods may or may not consider power flow analyses. In the prorata or postage stamp technique [4, 5], the total transmission cost is divided among the participants in the proportion of the magnitudes of their power injection under a specified operating condition. The postage stamp can also be used to supplement the rates calculated by more sophisticated methods to ensure the revenue of the total...
transmission cost. Still in this group, methods based on the principle of proportional division state that the flows that leave a bus through a set of circuits are proportional combinations of the flows that occur in them. In [6, 7], a nonlinear AC power flow solution is used to calculate the contributions of generators or loads to the flow in each circuit, and the same ratio is considered to allocate its cost. In [8], the value of Shapley [9] is used to confirm the principle of proportional division in the problem of allocation of power losses.

In the group of incremental methods, a basic condition is defined to which new transactions are superimposed. In this way, the cost associated with a transaction corresponds to the difference between the costs (operation, maintenance, and investments) of the system in the presence and absence of the analyzed transaction. The marginal methodologies basically consist of evaluating, for a given operating point, the variation in costs of the transmission system caused by the marginal change of some magnitude, e.g., the power injection of a bus. The economic signals indicated by marginal prices have justified the application of this type of method in the tariff systems of many countries [10].

There are, however, formulations that do not fit exactly into the groups listed in [3]. These methods are based on nodal impedance matrix [11, 12]; bilateral equivalent injections [13–17]; cooperative game theory [18–24]; Aumann-Shapley theory [25, 26]; transmission security margin [27]. Comparative studies are presented in [28–30].

The Nodal approach [31, 32] is the basis of the methodology currently used by the Brazilian regulatory agency, ANEEL, to allocate the transmission system costs. Countries like England, Colombia, and Panama also use the Nodal methodology, with small changes in relation to the model currently used in Brazil [33]. The method is based on the calculation of tariffs per bus, which considers the location of the agent in the transmission network and the magnitude of its power injection. This methodology results from the combination of a marginal method and the postage stamp, aiming to obtain a consistent economic signal in which the reward of the total cost of the transmission system is guaranteed.

In terms of energy sources, the Brazilian system is hydropower dominant with thermal generation as the main complement, but also with growing wind generation. Brazil has a continental territory that contains several hydrographical basins with frequent complementary behaviors, which requires great energy exchanges around all the geographical areas of the country, along a massive transmission network that is hardly entirely interconnected. The hydrothermal-wind planning operation can be determined by a chain of computational models [34], which handles problems with horizons starting from the short-up to the long-term. According to the study horizon, the representation of hydro, thermal, and wind plants and the peculiarities of the electric system are different. As an example, in long-term studies, it is more important to detail the stochasticity of the inflow or wind than accurate modeling of the transmission lines.

All computational models of this chain deal with stochastic dynamic problems of optimization and parallel computing. Thus, there is a growing effort in the literature toward decreasing the computational time and improving the convergence process of the optimization algorithms [35–39]. In the case of long-term planning, it is important to analyze the impact of the long-lasting droughts, their probability of occurrence, and the multiyear reservoir regulation capacity. In this phase, hydroelectric plants are represented in a simplified manner, but stochastic inflows are modeled in detail [38]. In long-term studies, the stochastic model of reservoir inflows must be represented accurately. Then, the uncertainty associated with the hydrological scenarios is represented in an explicit way, and all the other parameters are implicitly considered. Consequently, the effects of stochasticity in the primary energy sources must be modeled in detail.

Recently, some manuscripts were proposed to handle the welfare of integrated planning generation transmission. For example, [40] proposes a new approach to allocate transmission costs using Long Run Marginal Costs. In [41], a new methodology for transmission pricing is found based on load following and correlation factors in restructured environments. Finally, in [42], a new scheme was developed by utilizing point-to-point tariff and transaction pair matching.

This work proposes a new method to consider multiple hydrological scenarios in the nodal pricing of the transmission network, which is especially useful for systems with a predominance of hydroelectric generation, as is the Brazilian case, or similar renewable sources. The objective is to make tariffs compatible with the scenarios used in medium-term operation planning in order to promote the efficient use of the transmission system. The results are illustrated by numerical applications with the Brazilian electrical network, considering the 2014/2015 tariff cycle. Probabilistic analyses are performed to describe the annual costs of transmission of hydroelectric plants, thermoelectric plants, and industrial electrointensive consumers installed in different areas of the grid.

2. Generalization of the Nodal Methodology

The nodal tariff for a specific bus $i$ represents the sum of the costs of using the $nl$ circuits of a system with $nb$ buses, caused by the injection of $1$ MW in it. The initial tariffs, represented by a vector $\pi$ with dimension $(1 \times nb)$, are calculated as follows [32]:

$$\pi = CT \times DT \times \beta,$$

where $CT$ is a vector with dimension $(1 \times nl)$ of circuit costs to be recovered per year in $\$; $DT$ is the diagonal matrix $(nl \times nl)$, whose term $j-j$ is the reciprocal of the capacity of circuit $j$ in MW; and $\beta = zF/zP$ is the matrix $(nl \times nb)$ with the sensitivities of the vector of circuit flows $F$ $(nl \times 1)$, in relation to the vector of active power bus injections $P$ $(nb \times 1)$.

The application of these initial charges to the power injections recovers the cost of the used transmission capacity, $CTU$. This cost corresponds to the sum of the products between the cost per MW of each circuit and the
The corresponding power flow calculated at the specified operating condition, i.e.,

$$\pi \times P = \sum_{i=1}^{nb} \pi_i \times P_j = CTU.$$  \hfill (2)

The initial rates allow allocating the CTU among the participants. However, adjustments [32] must be made so that

(a) Tariffs become independent of the choice of the reference (swing) bus used in the calculation of the power flow and sensitivity matrix $\beta$, to ensure fairness and transparency to the method. Thus, the tariff vectors applicable to PG and PL, the generation ($G$) and load ($L$) vectors, respectively, for the use of the circuits are as follows:

$$\pi_i^{CTU} = \pi + \pi_0,$$

$$\pi_i^{CTU} = -\pi_i^{CTU}.$$ \hfill (3)

where $\pi_0$ is a vector ($1 \times nb$) with all elements equal to constant $c$ given by the following:

$$c = \frac{-\pi \times (PG + PL)}{\sum_{i=1}^{nb} PG^c_i + \sum_{i=1}^{nb} PL^c_{i}}.$$ \hfill (4)

(b) The tariffs calculated by (3) are responsible for the allocation of the cost of the transmission system utilized share among generators and loads. This CTU cost is divided between generation and load agents in the desired ratio, e.g., 50% for each class, as done in Brazil [31];

(c) Although the circuits are not required to work at its full capacity, their total cost should be allocated. The existence of the not utilized transmission capacity is due to investments in reinforcements and network expansion (e.g., “N-1 criteria”) in order to meet load and generation conditions predicted for the near future. The cost of the not used share of the transmission system is called CTN. It represents the value to be paid in a complementary way by the participants to cover the remaining capacity available in the network. The CTN can be calculated by the following:

$$CTN = TTC - CTU,$$ \hfill (5)

where TTC is the total transmission cost, previously established, and which should be allocated per year.

Conditions (a) and (b) are satisfied with the addition of a constant vector $\pi_0$ to the initial tariffs, which is equivalent to adopting a “virtual reference bus,” which tends to be in the area with the largest sum of generation and load [32]. Thus, if the physical reference or swing bus of the power flow and corresponding $\beta$ matrix is changed, new initial tariffs will be calculated, and a new adjustment constant will be obtained. However, its sum will always be the same, ensuring that the adjusted tariffs do not depend on the reference bus but only on the specified operating condition.

The allocation of the CTN, defined by (5), is done by a postage stamp, so that half of this cost is shared among generation agents and the other half among load agents. Thus, after adjustments, the tariff of any bus will have a locational portion responsible for allocating the CTU and a stamp portion, which complements the first one, to guarantee TTC’s recovery. Thus, the charges referring to the CTN for generation ($CG$) and load ($CL$) are calculated, respectively, by the following:

$$CG_j^{CTN} = \frac{CTN/2}{\sum_{i=1}^{n} PG_{inst}^c} \times PG_{j}^{inst},$$

$$CL_j^{CTN} = \frac{CTN/2}{\sum_{i=1}^{n} PL_{inst}^c} \times PL_{j}^{inst}.$$ \hfill (6)

In (6), the proportions of installed generation ($PG_{inst}$) and peak load ($PL_{inst}$) are used to prorate half the CTN among generators and a half among loads. The total charges for the generator and the load at bus $j$ are the sum of their charges associated with CTU and CTN, i.e.,

$$CG_j^{TTC} = CG_j^{CTU} + CG_j^{CTN},$$

$$CL_j^{TTC} = CL_j^{CTU} + CL_j^{CTN}.$$ \hfill (7)

Due to its marginal nature, the locational portion of the tariff may be positive or negative, while the stamp portion is always positive. Therefore, depending on the magnitude of the CTN, negative rates may arise. Generators in load areas and loads in generating areas typically reduce the use of the transmission, being viewed as “well placed in the network.” Although this signal is correct, revenue from the use of the network should be discussed if it makes the sum of payments larger than the total transmission cost. A procedure for eliminating negative allocations involves identifying the total negative amount and redistributing it via postage stamp among the positive assignees. Thus, agents who initially obtained a negative charge are free of cost, while the others have their charges reduced. This process is iterative and can be applied to generators and loads before or after the distribution of CTN. Besides, economic incentives can be given to specific technologies of renewable sources installed in some areas, if agreed by all market participants and regulators. In these cases, postage stamp corrections will have to be calculated to compensate for these incentives.

The final tariff is obtained by dividing the total charge by the installed (rating) generation or load at the bus. For the generator and the load on bus $j$, one can write the following:

$$\pi_{final, G, j} = \frac{CG_j^{TTC}}{PG_{j}^{inst}},$$

$$\pi_{final, L, j} = \frac{CL_j^{TTC}}{PL_{j}^{inst}}.$$ \hfill (8)

The final tariffs in $$//(MW \times yr)$ indicate the cost per MW of load or installed generation for the use and availability of
the transmission capacity in the calculation period (e.g., year).

Finally, the method, which aims to meet the characteristics of the Brazilian System, consists of the following steps [31, 32]:

1. Perform reading of electric data, desired dispatch condition, and costs of transmission elements;
2. Define if there will be the elimination of negative allocations and then choose the model, i.e., before or after the apportionment of the CTN;
3. Perform calculation of a DC linear power flow with transmission losses from the reported dispatch condition;
4. Based on the obtained operating point, calculate matrix $\beta$ and the initial nodal tariff vector;
5. Carry out tariff adjustments;
6. Calculate the transmission charge of each participant and their final tariff.

### 3. Hydrothermal Optimization

Due to the prevalence of hydroelectric plants in the Brazilian system and, consequently, its strong dependence on future inflows, optimized planning is carried out to minimize the expected cost of operation in the period of interest so that the demand is met within the desired reliability limit, even in unfavorable hydrological conditions [34–39]. The optimized planning accounts for the operational dependencies among hydro and thermal plants and the integration of the generation resources through the interconnection between areas.

The Brazilian Electric System is divided into 4 areas: North (N), Northeast (NE), Southeast/Central-West (SE/CW), and South (S). Because it is a dominant hydro system with thermal complementarity, it has distinct characteristics of thermal-based systems; see, for instance, [34–39]:

#### 3.1. Stochasticity

The randomness associated with uncertainties of future hydro inflows, which becomes more significant the longer the planning horizon is.

#### 3.2. Spatial Coupling of the Operation

The construction of cascade hydroelectric plants, i.e., in the same river bed, causes the operation of an upstream plant to interfere with the operation of downstream plants, unlike thermal plants that have an independent operation.

#### 3.3. Temporal Coupling of the Operation

The decision of the use of water resources in a month can cause adverse effects on the following months, as spilling the stored water (or even load shedding), which represent waste of energy.

Since the decision taken at one stage interferes in the future, if, for example, a lot of water is used from the reservoirs and a low rainfall occurs in the future, there will probably be high costs with thermoelectric generation and a risk of not supplying the energy demand. Conversely, high costs spent with the thermoelectric generation today associated with a high future rainfall index in the future could imply spilling water.

The hydrothermal operation in energy planning is determined by an optimization process, where each stage corresponds to a linear programming problem. In the SDDP (Stochastic Dual Dynamic Programming) formulation [39], when considering a given random variable, the objective is to determine the best operation. The SDDP is formulated as the following optimization model [38, 39, 43, 44]:

$$
\alpha_t(X_t) = E_{I_t,X_t}[\min\{C_t(U_t) + \alpha_{t+1}(X_{t+1})\}],
$$

subject to

$$
tg_{i,t} + hg_{i,t} + def_{i,t} = D_{i,t},
$$

$$
es_{i,t+1} = es_{i,t} + ei_{i,t} - hg_{i,t} - sen_{i,t},
$$

$$
es_{i,t+1} \leq es_{i,t+1} \leq \overline{es}_{i,t+1},
$$

$$
hg_{i,t} \leq \overline{hg}_{i,t},
$$

$$
tg_{i,t} \leq tg_{i,t} \leq \overline{tg}_{i,t}.
$$

Expression (9) represents the objective function for each stage, where $E_{I_t,X_t}$ is the expected operation cost of period $t$ or $(t+1)$ for a given inflow vector $I_t$ conditioned to state vector $X_t$ [38]; $C_t(U_t)$ is the immediate operation cost of the decision vector $U_t$. This vector is composed by the stored energy at the end of the stage, hydroelectric generation, spilled energy, as well as thermoelectric generation and unmet demand. Additionally, the objective function is composed of the expected future operation cost $\alpha_{t+1}(X_{t+1})$.

In (10), the demand $(D_{i,t})$ is met by the thermal $(tg_{i,t})$ and hydro $(hg_{i,t})$ generation and also considers the possibility of load demand deficit $(def_{i,t})$. The energy balance is expressed in (11), where the stored energy at the end of a stage, $es_{i,t+1}$, equals the stored energy at the beginning of this stage, $es_{i,t}$, plus the energy inflows to this subsystem during the stage, $ei_{i,t}$, minus the hydro generation, and the amount of spilled energy, $sen_{i,t}$. This equation represents the coupling between successive stages. The constraints (12) give the maximum stored energy, the constraints (13) give the maximum hydroelectric generation, and the constraints (14) give the maximum and minimum thermoelectric generation.

The aim of (9) is to minimize the total cost of operation, represented by the cost of the thermoelectric plants and penalties due to a possible shortage of energy. The problem is stochastic in nature and thus is divided into several sub-problems, i.e., as many as the known stages in the study horizon. In order to reduce the computational effort, the models aggregate the plants into equivalent reservoirs and at the end of the process, the solution of the equivalent reservoirs is disaggregated to verify if each plant is able to meet the corresponding amount of electrical energy.

The Brazilian electric sector officially adopts models for short and medium-term operation planning [34, 43–45]. The model described in [44, 45] is based on Stochastic Dynamic Programming.
Dual Programming (SDDP) to determine the strategy that minimizes the expected cost of operation over a horizon of up to 5 years, with monthly discretization. The generating plants are aggregated in such a way to represent subsystems interconnected by transmission ties. This model uses future cost functions and simulates the equivalent reservoir, allowing the calculation of the physical guarantee, i.e., the financial backing of the plant. The model presented in [43] also uses SDDP, but with a study horizon reduced to a maximum of 12 months, with weekly discretization in the first month. In this horizon, the physical characteristics of the plants and the electrical system are better detailed.

Similar models described in [43–45] were elaborated by agents of the Brazilian electricity market, tested, and approved by the Brazilian regulatory agency ANEEL [31]. These models are used in this work for assessing operational decisions considering different hydrological scenarios. The model [35] uses an SDDP-based approach together with the Convex Hull algorithm in a computationally efficient way (Fast Convex Hull). The main contribution is to propose a method for representing the future cost function in the linear programming problem, in which the computational time becomes less sensitive to the number of hyperplanes obtained by the algorithm of convex closure. The model [35] is based on nonlinear programming and uses future cost functions, produced as in [44]. The objective is to calculate the generation targets of each plant in order to minimize the expected value of the costs with thermal generation and energy deficit, as well as the future cost of operating the system.

4. Nodal Pricing with Multiple Hydrological Scenarios

The proposed methodology in this work consists of determining transmission tariffs based on hydrological scenarios obtained from actual energy models. This is carried out through the coupling of the nodal transmission pricing strategy described in Section 2 with the hydrological optimization model described in Section 3. The simplified flowchart of Figure 1 illustrates this coupling process. As mentioned, the energy models are responsible for supplying the dispatches to the electric model, which calculates the tariffs.

The first step is to choose the operative strategy for the energy models, which will be used by the electric network model. For each month of the analysis period, $N_H$ historical hydrological scenarios are processed. For instance, a past period between Year$_0$ and Year$_{NH}$, with segmentation in $n_s$-year sequential intervals, can be used. Therefore, considering the study tariff period [Year$_A$ to Year$_B$] in the near future and also the load condition of January-Year$_A$, the electric model uses $N_H$ different operational decisions of the energy models, depending on the different hydrological scenarios. The same occurs in February-Year$_A$, and so on, until December-Year$_B$, completing all months of the study cycle/period.

In the flowchart of Figure 1, Block “Energy Models” is the first one to be activated to provide all monthly optimized dispatching conditions for the study tariff period [Year$_A$ to Year$_B$], based on $N_H$ historical hydrological scenarios, which are considered equally probable. The usual network parameters are input together with the rating capacity of generating and load per bus; these are the data needed for a conventional load flow algorithm. The algorithm moves month by month for the charge/tariff analysis [Year$_A$ to Year$_B$] period using the optimized dispatching previously assessed, and this process is repeated $N_H$ times. In the end, all statistical results are exhibited to analysts and planners.

The procedure for transmission charging considering multiple hydrological scenarios allows the calculation of statistics for tariffs and nodal charges associated with the different scenarios. In this analysis, parameters such as mean and standard deviation, as well as the probability density function (PDF) and cumulative distribution function (CDF),
are determined for generation and load agents’ tariffs and charges.

Risk analysis means the calculation of the probability that the tariff or charge exceeds a certain value, defining the maximum financial exposure of the enterprise. If the agent holds several ventures, whether generation plants or manufacturing units, in different locations, the proposed method allows delimiting the risk assumed by the owners. It is, therefore, an important tool for decision-making, capable of providing information not available in the traditional method.

5. Application Results in the Brazilian Transmission System

The proposed method is applied to the Brazilian electrical system, Case 2014-2015, drawn up by the Brazilian ISO (Independent System Operator). The network representation has 6808 buses, 9413 circuits, and 680 power plants. The installed generation is 139,664 MW and the maximum demand is 87,628 MW. Figure 2 displays the Brazilian system, and Table 1 shows the distribution of generation and load amounts among the system areas. The Southeast/Central-West (SE/CW) area holds 54% of the total generation and load of the system, which indicates that the “virtual reference” will tend to approach this region. However, the location of this reference is defined as a function of the dispatch, which, in turn, depends on the associated hydrological scenario. Thus, the tariffs obtained will be sensitive to the hydrological scenarios.

For each month of the analysis period, \( N_H = 75 \) historical hydrological scenarios are processed. The period between 1931 and 2005, with segmentation with \( n_s = 5 \) -year sequential intervals, is used. For instance, considering the load condition of January 2014, the electric model uses 75 different operational decisions of the energy models, depending on the different hydrological scenarios. The same occurs in February 2014, and so on, until December 2015, completing all 24 months of the study cycle/period.

Although a large system is being used, program runs are fast. Considering 1800 (i.e., \( 75 \times 24 \) months) scenarios, transmission charges and tariffs are evaluated for all generators and loads in approximately 3 hours (6.01 s per scenario) using an Intel Core i7-3770 3.40 GHz processor. Running Energy Models block offline has spent about 10.8 hours in the same computer.

The calculations consider transmission losses in the DC linear flow analysis, elimination of negative tariffs for generators and loads after the allocation of the CTN, and

| Table 1: Brazilian system data. |
|--------------------------------|
| Area | Gen. (MW) | Load (MW) | Gen + Load (MW) | Percent |
| N    | 20,643    | 7,137     | 27,780          | 12%     |
| NE   | 19,377    | 13,128    | 32,505          | 14%     |
| SE/CW| 71,241    | 52,505    | 123,746         | 54%     |
| S    | 28,403    | 14,858    | 43,261          | 19%     |
allocation of the costs of interconnections between areas exclusively by postage stamp [32]. The TTC to be recovered is R$ 10,247,254  × 10³ per year (about US$ 2.0 billion per year, US$ 1.00 ≈ R$ 5.10—Brazilian currency) in the 2014-2015 cycle considering a 50 : 50% ratio between generators and loads. In the Brazilian electric sector, the TTC is called Annual Allowable Revenue [31].

In the analysis of the CTU share, it can be seen in Table 2 that the average value of the network usage charge considering the hydrological scenarios represents approximately 30% of TTC. However, during the evaluation of the hydrological scenarios, it is observed that the relationship between CTU and TTC varies from 21% to 37% due to the different dispatches to cope with the hydrological conditions.

The probabilistic analysis is performed for the main thermo and hydroelectric power plants installed in the four regions of the system, to evaluate the consistency of economic signaling. Table 3 presents parameters related to the tariffs of some generators obtained in the analysis with hydrological scenarios. It can be seen in Table 3 that the plants in the South and Southeast/Central-West regions have, in general, low average tariffs. This shows that when considering different hydrological scenarios, these market participants remain “well positioned in the network,” even with the variation in the condition of the transmission system usage.

Sobradinho and Termopernambuco power plants in the Northeast area, and Santo Antônio, in the North area present the highest average tariffs in Table 3. It indicates that, in general, these plants use the transmission more intensively than the others, and it also reflects their electrical position in the grid when considering the different dispatches. For the loads, whose tariffs are presented in Table 4, there is an inverse behavior compared to generators. While in the South and Southeast/Central-West loads (e.g., Açôs Longos and Charqueadas) present higher average tariffs, loads in the Northeast region (e.g., Açoñorte and Usiba) have the lowest tariffs. It can be concluded that average tariff movements for generating and consumer plants are related to the increase of the locational signal obtained by considering more consistent dispatching strategies to the actual system operation.

The following results are probabilistic evaluations of the annual costs of Termopernambuco generation plant in the Northeast area and Marimbondo hydroelectric power plant in the SE/CW area. The CDF and PDF in Figure 3 show R$ 0.00 and 66,501 × 10³ respectively, as an annual minimum and maximum charges for Termopernambuco power plant. It can be seen from Figure 3 that the average annual charge for Termopernambuco plant is R$ 33,424  × 10³. The coefficient of variation (relation between standard deviation and the average cost) is about 50%, confirming that the dispatch

| Charge | Average | Min. | Max. |
|--------|---------|------|------|
| CTU (10³ R$/yr) | 2,898,140 | 2,206,042 | 3,835,186 |
| CTU/TTC (%) | 28 | 21 | 37 |

| Tariff (R$/kW x month) | Area | Average | Min. | Max. |
|------------------------|------|---------|------|------|
| Angra I | SE/CW | 0.10 | 0.00 | 1.82 |
| Angra II | SE/CW | 0.05 | 0.00 | 1.58 |
| Itaipu | S | 0.45 | 0.00 | 3.55 |
| Jorge lacerda | S | 0.58 | 0.00 | 4.11 |
| Marimbondo | SE/CW | 1.29 | 0.00 | 4.18 |
| Santo antônio | N | 5.00 | 1.92 | 9.87 |
| Sobradinho | NE | 4.93 | 0.92 | 8.54 |
| Termopernambuco | NE | 5.36 | 0.00 | 10.66 |

Table 2: Cost of the used transmission capacity (CTU).

Table 3: Transmission tariffs—generators.

| Tariff (R$/kW x month) | Area | Average | Min. | Max. |
|------------------------|------|---------|------|------|
| Aço norte | NE | 2.07 | 0 | 11.91 |
| Açôs longos | SE/CW | 6.32 | 3.78 | 8.23 |
| Charqueadas | S | 9.74 | 3.11 | 13.07 |
| Usiba | NE | 1.86 | 0 | 11.31 |

Table 4: Transmission tariffs—loads.
of this plant is a determinant for the Northeast area to complement the hydroelectric sources. Risk analysis is important for the decision-making by the entrepreneur in the preparation and approval of budgets. There is, for example, a probability of 60% of the annual charge being limited to R$ 39,312 \times 10^3$. Marimbondo generation power plant in the Southeast/Central-West presents different interchange configurations with neighboring areas. In Figure 4, the annual charge varies from R$ 0.00$ to $72,042 \times 10^3$, with an average of R$ 22,155 \times 10^3$ and a coefficient of variation of 47%.

The previous analyses have considered isolated charges and tariffs for hydroelectric and thermoelectric generation and large manufacturing consumers. However, the proposed methodology allows evaluating portfolio risks for the agent that holds several ventures. Figure 5 shows the CDF and PDF of Gerdau, considering the factories (loads) of Table 4. Note that the agent charge has a coefficient of variation of 12%, i.e., lower than the generators, indicating that the possible charges are relatively close to the average, i.e., R$ 14,879 \times 10^3$, even in the face of great diversity of dispatches.

For educational purposes, consider that only the hydroelectric plants of Sobradinho and Marimbondo form the agent Eletrobras. Notice that the cumulative distributions of these ventures and the agent, shown in Figure 6, have different profiles. As expected, the average amount of the agent’s annual charge corresponds to the sum of the individual averages, which in this case are: R$ 62,022 \times 10^3$ for Sobradinho, R$ 22,155 \times 10^3$ for Marimbondo, and R$ 84,177 \times 10^3$ for Eletrobras. There is a 60% chance that annual charges will be limited to R$ 62,022 \times 10^3$ in Sobradinho and R$ 84,177 \times 10^3$ for Eletrobras. There is a 60% chance that annual charges will be limited to R$ 69,527 \times 10^3$ in Sobradinho and R$ 23,821 \times 10^3$ in Marimbondo. However, for the Eletrobras agent, the maximum charge with chances of 60% is R$ 87,918 \times 10^3$, therefore, less than the sum of the charges of its individual projects. The maximum charge reaches R$ 107,539 \times 10^3$ in Sobradinho, R$ 72,042 \times 10^3$ in Marimbondo, and R$
126,487 × 10^3 for Eletrobras. The minimum amounts are R$11,522 × 10^3 in Sobradinho, zero in Marimbondo and R$41,709 × 10^3 for Eletrobras. It should be emphasized that the most important information to compose the budget limit of the entrepreneur is the risk of the portfolio and not the individual ones.

Similarly, it is possible to carry out a probabilistic analysis for entrepreneurs that own several manufacturing units. Thus, consider the Votorantim Group, composed of the Siderúrgica and Metais Níquel units, both in the Southeast/Central-West area. The cumulative probability distributions of charges are shown in Figure 7. Because the profiles are different, one has a set of asymmetric functions, which makes the entrepreneur’s portfolio risk analysis very useful. For example, there is a 60% chance of the annual charge being limited to R$3,842 × 10^3 for the Siderúrgica unit, R$4,110 × 10^3 for the Metais Níquel unit, and R$7,928 × 10^3 for the group.

6. Conclusions

The consideration of hydrological scenarios in the charging process of the transmission system usage has been carried out for the Brazilian system. Differently from traditional tariff methods, where a single deterministic tariff is associated with each agent (generator or load), several tariff and charge samples have been used, representing a broad combination of diverse hydrological scenarios, i.e., from the driest to the wettest ones, with the seasonality of the monthly peak load, on the configuration of the Brazilian network tariff cycle 2014/2015. The concepts of probabilistic analysis are applied to these samples and the observed results are consistent and encouraging, with tariffs and charges that vary coherently depending on the dispatch strategy, promoting the intensification of the locational signal. Thus, it has been possible to discuss more realistically the consistency of the proposed method.

A risk assessment of expenses is proposed for the composition of the budget items of the companies, considering the portfolio of thermoelectric and hydroelectric power plants and manufacturing units. Other renewable sources such as wind and solar could be easily included in the risk analysis.

The proposed work can be implemented with the existing policies, by which tariffs are adjusted annually, adopting, for example, the average values resulting from the probabilistic analysis. Average values can provide more stable tariffs bearing in mind the dynamic of investments in generation and transmission along the time, thus ensuring a more acceptable environment for investors. Another option is to statistically establish two or three tariff levels along the year, bearing in mind the hydrological seasonality. Otherwise, operational procedures should be adjusted to reflect the processing of the data necessary for monthly charging calculations, which is at large more complex. The tariffs produced by the proposed method have a stronger locational component, burdening more the agents that use the transmission system the most. Therefore, the main policy implication is that there is a real and feasible calculation alternative for transmission tariffs in Brazil. Moreover, the concepts behind the proposed method can be easily extended to systems with high penetration of other renewable energy such as wind and solar. Thus, a clear tariff handling to stimulate these sources can be duly carried out.
### Abbreviations

| Abbreviation | Description |
|--------------|-------------|
| ANEEL | Brazilian regulatory agency |
| CDF | Cumulative distribution function |
| CG | Charge for generation |
| CL | Charge for load |
| CT | Vector of circuit costs |
| Ci | Immediate operation cost |
| CDF | Cost of the not used share of the transmission system |
| CTU | Cost of the used transmission capacity |
| CW | Central-west region |
| Dt | Load demand |
| de f | Load demand deficit |
| DT | Diagonal matrix of circuit capacities |
| t | Energy inflows during the stage |
| i,j | Stored energy at the beginning of a stage |
| e | Stored energy at the end of a stage |
| e | Maximum stored energy |
| e | Minimum stored energy |
| h | Hydro generation |
| h | Maximum hydroelectric generation |
| I | Inflow vector |
| nb | Number of buses |
| N | North region |
| NE | Northeast region |
| Nj | Historical hydrological scenarios |
| nL | Number of lines or circuits |
| P | Active power bus injections |
| PDF | Probability density function |
| PG | Active power generation |
| PG | Installed (rating) generation at bus j |
| PL | Active power load |
| PLj | Peak load at bus j |
| S | South region |
| SDDP | Stochastic dual dynamic programming |
| SE | Southeast region |
| sen | Amount of spilled energy |
| t | Thermal generation |
| T | Maximum thermoelectric generation |
| t | Minimum thermoelectric generation |
| TTC | Total transmission cost |
| U | Decision vector |
| X | State vector |
| a | Objective function for stage t |
| β | Matrix with the sensitivities of circuits flows in relation to active power bus injections |
| π | Vector of tariffs |
| π | Final tariff for generator at bus j |
| π | Final tariff for load at bus j |

### Data Availability

The input data used to support the findings of this study were supplied by the Brazilian Independent System Operator under license and so cannot be made freely available. Requests for access to these data should be made to the first author Carlos R. R. Dornellas via the email “crrdornellas@gmail.com.”

### Conflicts of Interest

The authors declare that they have no conflicts of interest.

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