AVAILABLE TRANSFER CAPABILITY INFLUENCE ON ENERGY PORTFOLIO

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Abstract – **This paper presents an approach to deal with the spatial basis risk for energy transactions. The concepts of hydrothermal coordination are described especially because it has a crucial effect in Brazil, where 92% of the power generation comes from hydropower. The spot market prices are derived from an optimization program, which performs the hydrothermal coordination. The volatility of the prices is high and this is stressed when the transmission constraints are considered. The probabilistic nature of the available transfer capability (ATC) needs to be incorporated to the risk and return assessment. So, a combined approach between the price forecasts due to hydrological uncertainties and the probabilistic ATC is developed. Probabilistic density functions are built to help the analysis of energy portfolios, i.e., to help in the decision-making process about long or short-term contracts. Example with the Brazilian electrical system is used to clarify the concepts presented in this paper.**

Keywords - ***Marginal Cost, Available Transfer Capability, Portfolio Analysis, Market Risk***

I. INTRODUCTION

The portfolio theory is a well-known technique applied to financial markets [1], where a set of investments or contracts is composed to perform a better combination between return and risk. The current restructuring process of the electrical sector has allowed the inclusion of such a technique on the new electricity market. A serious problem of the electricity markets is the transportation of this commodity, since it is dependent on the transmission network. The way the transmission aspects are internalized in these markets varies from country to country. In Brazil, for instance, there are four sub-markets where the price of electricity is determined. They were formed based on the structural transmission constraints, which give rise to the transmission congestion. If one agent buys electricity from a generator that is in another sub-market, he/she is exposed to a risk of not having enough capacity to transfer the energy.

Many papers have been dealing with the available transfer capability – ATC [2], which is a limitation on the transmission network that does not allow the power to go from one bus or set of buses to other ones. In reality, such limits depends on the load that varies along the day, voltage limitation, circuit or generator outages and the dispatch of the generators, which in general, is coordinated by an independent system operator (ISO). Therefore, the ATC has a probabilistic nature and cannot be dealt by conventional deterministic approach.

Dealing with transfer capability requires, therefore, the analysis of several operating scenarios. Note that not only the topological aspects of the system are relevant. The inclusion of the economical considerations also plays a very important role. In this sense, the nature of prices (zonal or nodal) is crucial. In this work, zonal price is considered, and some issues associated with market definition are discussed.

This paper proposes a method that combines the probabilistic characteristics of ATC with the volatility of the zonal prices. In Brazil, the zonal prices or the sub-market prices depend not only on the fuel prices of the thermal generation but mainly on the hydrological conditions. Moreover, the spot prices are determined by an optimization process to preserve the centralized dispatch of the generation system.

Transmission constraints impose another source of risk, which is known as spatial basis risk [3]. If one agent wants to hedge his contracts that involve more than one zone or sub-market, he/she needs to take the spatial basis risk into account. This additional risk will probably affect the Value at Risk [4] of the agent portfolio. This paper tries to quantify this exposure.

An actual example with the Brazilian electrical system is used to show the method proposed in this paper. Some interesting features appear from the analysis of the results.

II. ELECTRICITY MARKET

The power industry restructuring process under development in many countries has brought the competition at the generation and commercialization of electricity [5]. The implementation of the electricity markets is a reality today, although some drawbacks have been witnessed and vary from country to country. One major problem is the transmission and distribution interference on the market. Although the regulation about open access and tariff is evolving, many challenges have been observed, such as dealing with gaming among the agents, difficulties to establish the actual transmission boundaries, the power of the independent system operator – ISO, the trade-off between transmission expansion and operational constraints, etc.

The transmission and distribution (T&D) systems impose constraints to the electricity market. Hence, if a contract is made between two agents who are in different points at the T&D grid, there is a risk involved because of the system constraints. The management of such a risk will depend on the regulation of each country. In Brazil, as shown in Figure 1, there are four sub-markets: Northern, Northeastern, Southeastern and Southern sub-markets. The energy prices may vary between them due interface constraints and uneven hydrological conditions. The internal T&D constraints of one sub-market are not internalized in the market and an additional fee is provided to balance the costs between the agents who were constrained-in and the others that were constrained-off. The fee is imposed to all generators and consumers who belong to this sub-market. In Brazil, the definition of the number of sub-markets and their interfaces are proposed by the ISO for every five years.

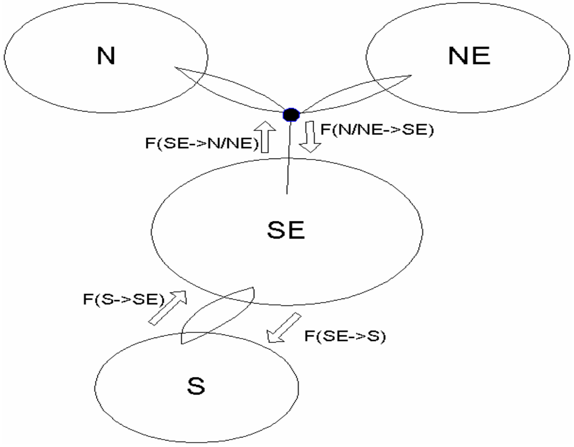

Figure1: Sub-markets in Brazil

The buyers and sellers can trade by bilateral contracts or use the spot market in Brazil. The bilateral contracts comprise the forward market, which is free in terms of standardization. In Brazil, the spot price is not derived from an auction process, as it is in the majority of electricity market experiences. The generation system is hydro dominated and some concerns about the auction process were raised during the creation of the current model. The worries about the lack of optimization related to the reservoir operation were the primary reason why the current price mechanism was adopted. The spot price of MAE, the Wholesale Energy Market, is equal to the marginal cost obtained by solving a stochastic dynamic program.

This program calculates the marginal costs of each sub-market or zone. For each zone, an equivalent reservoir is used to represent all the hydro plants inside this area. Also, equivalent inflow sequences are determined based on the individual inflows to each reservoir. The computer package named NEWAVE [6] performs the calculation of the marginal costs at each zone. In this case, there are four nodes representing the four sub-markets and one connection point. The transmission constraints between the zones are informed to NEWAVE, i.e., the power transfer limits from sub-market k to sub-market l, $\overline{\mathrm{F}}\,(\mathrm{k} \Rightarrow \mathrm{l})$.

The dynamic optimization problem (1) is carried out through five years with a step of one month. Benders decomposition and Monte Carlo Simulation technique are used to solve this problem [7]. The solution approach is based on the approximation of the expected-cost-to-go functions of dynamic programming at each stage by piecewise linear functions. These approximate functions are obtained from the dual solutions of the scheduling problem at each stage and may be interpreted as Benders′ cuts in a multistage decomposition algorithm.

$$\alpha_{\mathrm{t}}(V_{\mathrm{t}}, A_{\mathrm{t-1}}) = \mathrm{Min}\left[\ \sum_{j=1}^{N_t} c_{\mathrm{j}}\, g_{\mathrm{tj}} + \beta\, \alpha_{\mathrm{t+1}}(V_{\mathrm{t+1}}, A_{\mathrm{t}})\ \right] \qquad (1)$$

subject to

$$v_{\mathrm{t+1,i}} = v_{\mathrm{ti}} + a_{\mathrm{ti}} - u_{\mathrm{ti}} - s_{\mathrm{ti}} + \sum_{m\,\varepsilon\, M_{\mathrm{i}}} [\, u_{\mathrm{tm}} + s_{\mathrm{tm}} \,] \qquad \pi\mathrm{h}_{\mathrm{ti}}$$

$$v_{\mathrm{t+1,i}} \le \overline{v}_{\mathrm{i}} \qquad \pi\mathrm{v}_{\mathrm{ti}}$$

$$u_{\mathrm{ti}} \le \overline{u}_{\mathrm{i}} \qquad \pi\mathrm{u}_{\mathrm{ti}}$$

$$g_{\mathrm{tj}} \le \overline{g}_{\mathrm{j}} \qquad \pi\mathrm{g}_{\mathrm{tj}}$$

$$\sum_{i\,\varepsilon\, I_{\mathrm{k}}} \rho_{\mathrm{i}}\, u_{\mathrm{ti}} + \sum_{j\,\varepsilon\, T_{\mathrm{k}}} g_{\mathrm{k}} + \sum_{l\,\varepsilon\, \Omega_{\mathrm{k}}} F_{\mathrm{kl}} = d_{\mathrm{k}} \qquad \pi\mathrm{d}_{\mathrm{k}}$$

$$F_{\mathrm{tkl}} \le \overline{\mathrm{F}}\,(\mathrm{k} \Rightarrow \mathrm{l}). \qquad \pi\mathrm{f}_{\mathrm{kl}}$$

where

$v_{\mathrm{t+1,i}}$	reservoir volume in plant i at step t+1
u_{ti}	water flow used to generate power in plant i at step t
s_{ti}	water flow spilled in plant i at step t
g_{tj}	thermal generation in plant j at step t
ρ_{i}	hydro plant productivity
F_{tkl}	power flow from zone k to zone l at step t
πx	dual variables associated to the constraints
c_{j}	operational costs for thermal plant j
$\alpha_{\mathrm{t}}(V_{\mathrm{t}}, A_{\mathrm{t-1}})$	operational cost at step t including the future costs.
$\mathrm{M_i}$	set of upstream hydro plants derected connected to hydro plant i.
$\mathrm{a_{ti}}$	lateral inflow of hydro plant i

For the NEWAVE algorithm, the stochastic nature of the water inflows, a_{ti}, is taken into account. An autoregressive modeling of the periodic hydrological series is used as the input to the dual optimization program [8]. Monte Carlo Simulation is the core of that algorithm, establishing the connection between the deterministic optimization and the stochastic nature of the water inflows.

The dual variable πd_k represents the marginal cost associated with the demand at sub-market k. As for the current market structure in Brazil, this marginal cost is equal to the spot price at this sub-market. Then, for each step and for each hydrological sequence, it is possible to calculate this price based on the dynamic programming problem (1).

The power exchanges between sub-markets are limited by a fixed quantity previously informed, $\overline{F}(k \Rightarrow l)$. The next section incorporates the stochastic nature of these exchanges.

III. PROBABILISTIC ATC

The topic of ATC determination is an issue of concern to both power system planners and operators. For example, under FERC Order 888 and 889, all transmission providers must determine and offer for sale ATC taking into account the existing obligations and allowing appropriate margins to maintain reliability.

The maximum power flow permitted in a transmission interface is bounded by thermal, stability and voltage limits. The smallest of these limits defines the Total Transfer Capability (TTC) of the interface. In addition, transmission provider may impose a Transmission Reliability Margin (TRM), which is a reliability-related quantity subtracted from the TTC. The ATC is then obtained as the difference between the scheduled/committed transfer and the value of TTC. Both TTC and ATC are functions of system configuration, generation capacities and loads. All of these variables present a probabilistic behavior and therefore cannot be treated based on deterministic approach [2].

The concept of ATC or Probabilistic ATC can be extended to the interconnection of two sub-markets, where the probabilistic ATC associated with the interface can be expressed by a probabilistic density function.

Using a DC power flow, it is possible to determine the maximum transfer using Equation 2. Although a DC model is applied in this paper, similar approaches can be extended for AC power flows models.

$$Max\,[\alpha_1 \sum_{j=1}^{NT} F_j - \sum_{k=1}^{Nbus} \alpha_2 \Delta L_k\,] \qquad (2)$$

subject to

$P=B\theta$: DC power flow equations

$Pg_i^{min} \le Pg_i \le Pg_i^{max}$: capacity of each generator i (MW)

$F_l^{min} \le F_l \le F_l^{max}$: flow capacity of each circuit l (MW)

$0 \le \Delta L_k \le L_k$: load shedding at bus k (MW)

where:

F_j : active power at interface circuit *j*

Nbus : number of busses at the system

NT : number of interface circuits

α_1 : flow penalty (US$/MWh)

α_2 : load shedding penalty (US$/MWh)

The objective function of problem (2) seeks simultaneously the maximum TTC while shedding the minimum load. If the penalties values are such that $\alpha_2 >> \alpha_1$, the linear program algorithm will try first not to shed load and, then, maximize the power transfer. In reality, α_2 is necessary when one circuit outage, away from the influence zone of the TTC, causes a load shedding. In this case, this contingency cannot interfere on the assessment of the TTC. On the other hand, it is not allowed to shed load in order to increase the TTC and the relation of the α_1 and α_2 deals with this premise, i.e., for loads that belong to the TTC influence area there is no load shedding associated to them.

Note that in the objective function of problem (2), the generation costs are not taken into account In this case, the objective is to maximize the power transfer and not minimize the operational cost, which is performed by problem (1). The aim is to decouple the transmission problem with the generation problem and minimize the computational effort. Tests with generation cost functions were performed and the results did not change for costs lower than α_1. The use of transmission capacities will depend clearly on the price signals between the sub-markets delimited by the interfaces.

For each system state obtained by a Monte Carlo Simulation, where the reliability indices are considered, the maximum transfer is determined through problem (2) and this point is stored to form the probabilistic density function. The convergence criterion is based on the average TTC and the associated β index [9]. Then, the ATC function can be determined based on the TTC function and the power flow conditions at the interfaces. The flow conditions come from the optimization problem (1). In this paper only the heavy load period was considered in the assessment of TTC, assuming that this condition will last during the whole month. As the TTC strongly depends on the base case or on the time period, a lower time step, which is currently one month, is being introduced in the computer package for the energy market in Brazil.

IV. VaR ASSESSMENT

Given a portfolio of investments with an initial value W_0 and a return R, the future value for a given horizon will be $W = W_0\,(1+R)$. Considering R as a random variable, the future value can be represented as a probabilistic density function, f(W). The graphic of Figure 2 presents this function.

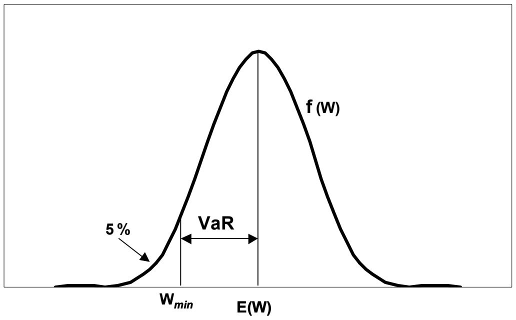

Figure 2: VaR Definition

The value at risk (VaR) of the portfolio is the difference between the expected value of W, E(W), and the minimum value W_{Min} for a given confidence interval c, where:

$$c = \int_{W_{Min}}^{\infty} f(W)dW \qquad (3)$$

In other words, the area between $-\infty$ to W_{Min} must sum p = 1 – c; for example, 5 %. This value is very usual for the majority of the financial institutions. The concept of VaR is very important as a measure of the real risk of a portfolio. The previous definition of VaR may be interpreted as the relative VaR [4] when compared with the traditional absolute VaR, which represents the value W_{min} .

In the case of energy systems described earlier, it is possible to combine the price volatility in each sub-market with the probabilistic TTC and finally find the influence of the transmission constraints in terms of VaR.

If the optimization program described in the previous items can predict energy prices, the return R can also be determined. Suppose that a thermal generation owner wants to sell energy. In the Brazilian market, there are two options: sell it at the spot market or make bilateral contracts. It is also possible to combine these two options. If he/she sells the whole energy to the spot market, his/her return will directly depend on the future market prices. On the other hand, if only bilateral contracts are made, he/she prevents from the price volatility but cannot benefit from high spot prices.

From TTC studies, it is possible to obtain the probability of the power transfer between sub-markets being less or greater than a certain limit $\overline{F}$ (k $\Rightarrow$ l). For instance, the probability $\Pr\{F < \overline{F}(k \Rightarrow l)\}$ is the area under the TTC density function to the left of $\overline{F}$ (k $\Rightarrow$ l). Moreover, it is also possible to determine the probability $\Pr\{\overline{F}_1(k \Rightarrow l) < F < \overline{F}_2(k \Rightarrow l)\}$, where the power transfer is between two limits. Figure 3 shows this probability represented by the shaded area. In the next item, this relative frequency of the values from $\overline{F}_1(k \Rightarrow l)$ to $\overline{F}_2(k \Rightarrow l)$ was simplified to a unique flow limit (Figure 5).

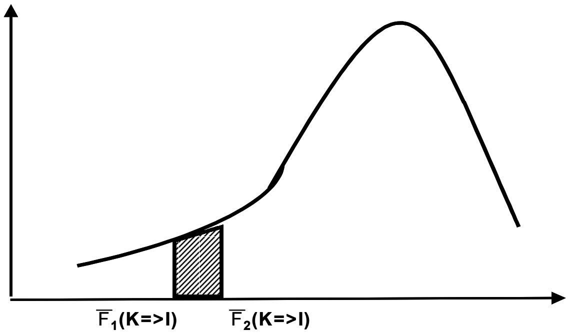

Figure 3: TTC Density Function

From NEWAVE results, the probability density function of the energy prices in each sub-market for a certain interface limit is assessed. It was observed that the TTC function is independent from the hydrological conditions, and therefore, there is no correlation between them. Then, it is possible to determine the combined distribution function of price volatility and the TTC. Therefore the spatial basis risk of a certain energy portfolio may be assessed.

Given the combined density function of TTC and price forecasts, the VaR can be calculated based on the expected return, which depends on how the portfolio was formed.

V. CASE STUDY

The Brazilian electrical system is used to clarify the proposed method. Table 1 shows the generation capacity and load in each sub-market.

Table 1: Brazilian System Data

Sub-market	Generation Capacity (MW)	Peak Load (MW)
S	11,635	10,162
SE	39,326	36,639
N	4,281	2,902
NE	10,427	8,017

Figure 4 shows the price density function assuming that no transmission constraints are active, i.e., only one market is considered. These density functions were obtained using the synthetic hydrological series [8]. In the same figure, there are two other density functions for the Southern (S) and Southeastern (SE) sub-markets, but now the $\overline{F}$ (SE $\Rightarrow$ S) and $\overline{F}$ (S $\Rightarrow$ SE) are both equal to 2000 MW.

As expected, the density function for one single market, i.e., with no transmission constraints, is in the middle of the other two ones. The prices for the Southeastern sub-market are high because they reflect the current rationing problem in Brazil. When the transmission constraints are actives, the prices differ and, as the Southern region is an export area, its prices tend to be lower than the prices of the Southeastern region. In this case the difference is substantially high and denotes the energy deficit at the Southeastern region. The prices have a ceiling at R$ 700.00 or US$ 280.00, which corresponds to the deficit cost. This cost is an input to the NEWAVE program and this is included in the optimization process as an artificial generation, with a production cost equal to the deficit cost. It is important to mention that this is a criterion in the Brazilian market.

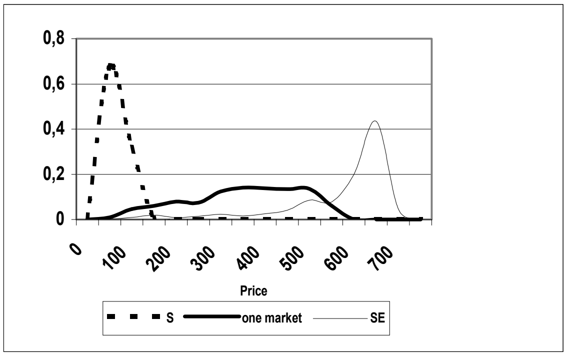

Figure 4: Price Density Function

The TTC probabilities were determined for this interface and are depicted in Figure 5. This interconnection between these two regions has two transformers (500/750 kV and 1650 MW each) and other 88 kV transmission lines.

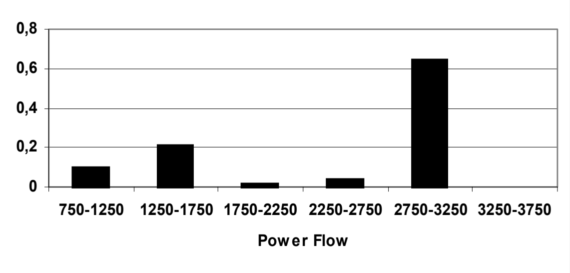

Figure 5: TTC probabilities

The TTC function is separated into seven portions to simplify the combination with the price density function. For instance, the probability of having a TTC from 1750 to 2250 MW is 1.25%. This probability is used to weight the price density functions. The combined TTC and price function for Southern sub-market is shown in Figure 5.

An agent, who owns a thermal plant at the Southern region, wants a reasonable return on the investments and calculates the desired energy price to accomplish this objective. Let us assume that this expected value is R$ 150.00 per MWh. From the combined density function of Figure 6 and assuming a confidence interval of 5%, the VaR associated to each MWh is R$ 127.00, if all the energy produced is sold in the spot market. If only one market is considered (see Figure 4) the VaR would be R$ 53.00. As expected, transmission constraints increase the VaR and one way to minimize such risk is doing bilateral contracts, i.e., using the forward market. Based on the energy price density functions, a portfolio of bilateral contracts can be constructed according to the utility function of the agent.

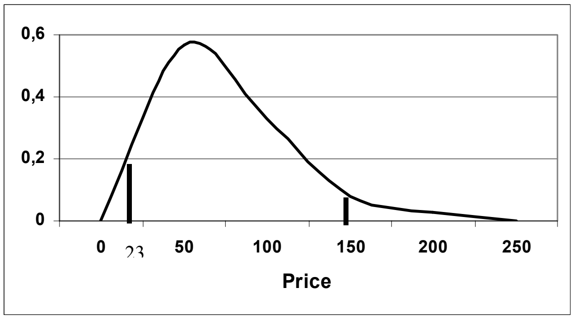

Figure 6: Southern sub-market prices

Bilateral contracts can be made between agents in the same sub-market or in different sub-markets. The agents in the latter case are also subjected to spatial basis risk. Figure 6 presents the price differences, Δp, between the two sub-markets. For instance, assume that an agent A sells energy to an agent B at a price R$ 150,00 and the prices in each sub-market are not equal. Hence, agent A will sell energy at sub-market S with a price P(S) and will buy the same amount at sub-market SE with a price P(SE) in other to fulfill the contract. This difference represents investment losses, which should be previously quantified.

In this case, the expected difference should be zero in order to not compromise the expected return of the bilateral contract. The VaR per MWh should be R$ 660.00, which is the maximum price difference for 5% of confidence interval given the density function of Figure 7. Again, combined portfolios can be constructed based on this price difference density function.

Figure 7: Price Difference Density Function (Δp)

VI. CONCLUSION

This paper proposes a method that combines the probabilistic characteristics of ATC with the volatility of the zonal prices. In Brazil, the zonal prices or the sub-market prices depend not only on the fuel prices of the thermal generation but mainly on the hydrological conditions. The spot prices are currently determined by an optimization process to preserve the centralized dispatch of the generation system. So, the paper works directly with the computer packages that provide the spot price forecasts. The VaR approach was used to identify the risk exposure of an agent who owns a thermal generating unit, but the concepts described here may be applied to any kind of generation portfolio.

The results show the importance of considering the available transmission capacity. In the example, for an agent in the Southern region, the VaR changed from R$53.00 (one market is considered) to R$127.00 (four markets considered) per Mwh. This wide change in the risk indicates that this kind of study must be carefully carried out.

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