A Business Model to Incentivize Hydro Companies Inversions in Wind and Biomass Power Plants

L. A. S. Camargo, E. Guarnier, L. T. Witzler and D. S. Ramos

Abstract— **The complementarity among renewables power plants is an important issue in the Brazilian Energy Market. Wind and biomass generators have increased their market shares and typical hydro companies are investing in such projects to obtain gain of scale. We developed a support decision model that allows complementarity analysis and valuation of financial benefits that investments in wind and biomass power plants can provide to a hydro company. These benefits arise from a hedge effect originated by the seasonal generations' synergism among such power plants and which improves the return over the capital expenditure and the portfolio risk profile. The model searches for an optimized solution aided by Genetic Algorithmic method and uses CVaR as risk metric. A business model is suggested and applied in a case study. The performance results confirmed that complementarity effect brings financial benefits for the hydro company when such sources are part of the generation Portfolio.**

Index Terms- **Renewable Energy, Complementarity, Trading Strategy**

I. Introduction

ENERGY markets have been expanded worldwide through investments in renewables, accounting for approximately 257 billion USD in new capacity during 2011 [1].

In the Brazilian energy market, a recognized hydroelectricity producer (88 GW of hydro power capacity), wind power capacity has been rapidly expanded chiefly due to local government incentives and as result its installed capacity is estimated to grow from 3.2 GW in 2012 up to 11.5 GW in 2020, over half in the Northeastern region [2].

With similar governmental incentives given to wind power plants and as a result of the huge sugar cane agriculture activity, biomass power plants capacity, based on cogeneration using sugar cane bagasse, have been increasing steadily, reaching 7.3 GW in the end of 2011 [1].

Due to these positive market conditions and to obtain gains of scale, large generator companies - typically hydroelectricity independents producers - are diversifying their assets portfolio by investing in biomass and wind power plants.

In a general manner, renewable sources have different generation profiles, which in the Brazilian conditions follows: biomass power plants tend to generate only during certain harvest months (usually from May to November); wind power plants monthly average production tends to increase from June to November; and hydro power plants production increases during the wet season, which goes from December to April.

Furthermore, during the high biomass and wind power plants productions period, spot prices tend also to be high. The opposite occurs during the wet period (as spot price is determined by the cost of the most expensive thermoelectric dispatched, hydroelectricity production is negatively correlated to spot price).

These facts increase the generators' risk of selling high amount of its firm energy as yearly firm contract, becoming necessary develop trading strategies to avoid Spot Market Prices (SMP) risk exposures by making agreements with different seasonal sources, in order to take advantage of this natural complementarity characteristic among wind, hydro and biomass power plants generation (See [3] and [4]).

In addition, an asset portfolio diversification requires specific analysis of the correlation among these news projects and an existing portfolio to account for the extra value that it could add to the set of power plants.

Thus, comes highlight up the discussion about trading strategic arrangements and investment valuations in new real assets by considering the jointly effect over the original portfolio (the complementarity of generation projects) and based on the fact that the overall production can be traded as one block, supported by regulatory rules, as it is shown in next Section II.

In this paper, an optimization model is presented to analyze the attractiveness for hydro generator companies' investments in wind and biomass power plants projects and a business model to build this strategy up is proposed.

Our optimization model allows analysis of these projects feasibility concomitantly with their portfolio effect and by simulating long-term trading arrangements. It embeds the uncertainty of spot prices and generation profiles, uses the CVaR risk measure as a constraint and is optimized through Genetic Algorithm technique.

Considering the insights we got from practical applications, we analyze the energetic synergism among a hydro company and candidate projects - wind and biomass power plants - and the financial hedge among them by trading the total plant energy production as one block.

Our results show that the benefits of investing in such projects can incorporate an extra value not captured by traditional analysis. The generation complementarity

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characteristic of these sources is an important key to be considered in such analysis and the proposed model is able to take this into account as consider the synergism between different projects.

The paper is organized as follows. Section II introduces the Brazilian energy market overview and the main trading regulatory rules. The renewables projects synergism in Brazil is discussed in Section III. The optimization and business models embedded in the valuation framework are presented in Section IV. Section V presents the data used to create scenarios of electricity prices and power plants generation, which support, in the next Section VI an illustration with a case of study. Section VII concludes the study.

II. Brazlian energy market

A. Overview

The Brazilian Power System (BPS) is one of the largest interconnected systems in the world, with more than 120 GW of installed capacity, composed mainly by hydro generation - representing 80% of the total installed capacity and 90% of all energy generated.

The BPS is also composed by a mix of thermal power plants from different sources including natural gas, coal, nuclear and oil. Wind power plants and bioelectricity units (co-generation often associates with ethanol production process, using sugarcane bagasse as a fuel) are considered a competitive alternative for the BPS expansion.

As the Brazilian generation matrix is mostly composed by hydro generation and also a number of power plants from different owners located in the same river cascade, the combined effect of those characteristics led to a decision that the generation dispatch in Brazil should be centralized, which means that the decision of how much each power plant should generate, at every given time interval, is made by the National System Operator (NSO).

The objective of these operational procedures is to capture the wide weather's complementary behavior among regions, seeking to minimize the total generation costs and maintain the system supply reliability, accounting as variable decisions the hydro and thermoelectricity generation dispatches.

The operation is computed by a multi-stage stochastic optimization model (named Newave) that takes into account a detailed representation of hydro and thermo plants, the capacity expansion, the demand forecast, the interconnection transmission limits between subsystems (for instance, between South and Southeast regions) and inflow uncertainties in order to determine the thermo and hydro optimal dispatch [5], [6]. Due to the innumerous combinations for such operation planning, hydro power plants representation is modeled as 4 equivalent systems, related with the geoeletric regions North, Northeast, Southeast and South.

Supported by the Newave, hydro and thermo power plants are dispatched by the NSO and, as a result of this computation, the system's marginal operating costs are obtained. Thus, limited by pre-defined cap and floor prices (upper and lower bounds for spot price), the correspondent Spot Market Price (SMP) is reached. We used information from Newave in our study as it is the same model used by NSO.

From the consumers' perspective, one basic regulatory rule lies on the obligation that all consumers should have supply contracts corresponding to 100% of their loads. The contract is accounting ex-post, comparing the MWh consumed with the MWh contracted. The difference between contracted and consumed is settled in the Spot Market (SM).

From the generators' perspective, the basic regulatory rule is the obligation that all financial contracts should be ballasted by the Firm Energy Certificate (FEC), an energy credit given by the regulator to facilitate the electricity trading for each generating unit plant in the system. Basically, the FEC defines the maximum amount of energy that a power plant can sell through a bilateral contract.

These jointly rules for consumers and generators aim to guarantee that all energy traded in the system do not exceed the system supply capacity. Moreover, the rules provide a link between the load growth and the guidance for the system installed capacity expansion.

The system's total FEC is calculated based on hydrological scenarios simulations, whereby the total system credit is obtained when the system marginal operating cost equals to the system marginal expansion cost, with an additional constrain that limits in 5% the probability of energy deficit in any submarket. Then, for each power plant is given a proportion of the total credit, according to the benefits that this sources brings to the system under adverse conditions.

Another important regulatory matter, specific for hydro power plants, is the Energy Reallocation Mechanism (ERM), which mitigates the generation's risk, as they are exposed to the unpredictability and volatility of water flows.

The ERM ensures that, under normal operating conditions, hydro generators would receive the income associated with their firm energy by reallocating generation from those in surplus to those in deficit. Then, ERM shares the generation risks between all hydro generators, catching the complementary among different river basins. As a result, the mechanism scheme decreases the financial impact associated with the hydrologic risk that comes from the centralized dispatch. See more on [7] and [8].

B. Trading regulatory structure

For generation companies, production uncertainty implies to face risks from the stage of investment decisions up to the energy trading strategies development. The higher uncertainty in the production and electricity price, the higher should be the impact over company's decisions.

The uncertain seasonal production and its correlation with demand and spot price affect decisions over the amount of energy that should be allocated in derivatives contracts (forward and futures). An inappropriate decision now could result in spot market exposures in the future. Because of these facts, companies have created strategies to hedge their positions by diversifying in renewable sources or buying/ selling derivatives contracts [3] , [4], [9] and [10].

During the yearly period when wind and biomass power plants have maximum productions, spot prices are, in general, also high and the opposite occurs during the wet period.

In Fig. 1 one could observe the typical hydro, wind and biomass generation profiles represented by their percentage of the Installed Capacity and the spot price average profile. Hydro Generation profile representation accounts the ERM generation effect.

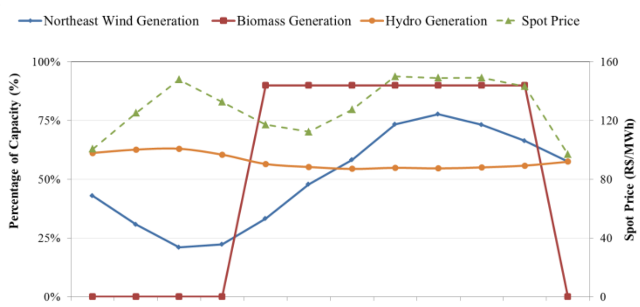

Fig. 1. Typical Hydro and Wind Generation Profiles

The basic contract traded in the BPS is named contract by quantity, where the delivery volume profile, maturity period and price are fixed in advance. Companies can allocate up to their equivalent FEC in such contracts, usually, in long-term.

Under a condition of one generation higher than the overall volume allocated in contracts, they can sell the surplus on the SM. And, on opposite condition, where the generation is lower than the volume allocated in contracts, they should buy the difference in the SM.

These facts in addition to the seasonal and uncertain energy production make all generators averse to sell high amount of its firm energy as yearly firm contract, searching for trading strategies to avoid risk exposures to the Spot Market Prices (SPM). On the other hand, long-term contracts such as Purchase Power Agreements (PPA) are the most common type of contracts searched by consumers and distributors.

III. Renewables Projects Synergism

The growing of renewable sources market share and its insertion effects into energy markets worldwide, on the light of complementarity approach, are studied by many: [11], [12], [13], [14] and [15].

A mechanism to mitigate individual risks and attract wind generators to the wholesale market in U.K., based on Brazilian hydro experience, is proposed in [7] and a similar discussion for the Brazilian wind power plants case is done in [8].

Trading strategies taking into account renewables and complementarity can be seen in [3], [4], [9] and [10].

As presented in Section I, renewable productions patterns, such as biomass, hydro and wind power plants have a natural complementary synergism in the Brazilian territory, which becomes more complex when accounting the spot price volatility, given its dependency with hydropower dispatches and the system conditions.

The gains of synergism arise from the fact that the diversity of seasonal production capacity of renewables can be used as a manner of mutually cover SM exposures.

Thereby, it is materialized the fact that together, complementary agents can very often trade without excessive risk an amount of the overall FEC level that exceeds the sum of the amount that each agent could trade individually, given one same risk level.

The energetic complementation among different generation sources, under Brazilian regulatory rules, can be seen as a natural financial hedge mechanism for generator companies.

The financial benefits that generators can obtain while making the decision in new investments compounding a portfolio by different sources depend on some technical and market factors that can be summarized as (i) the synergism among the sources, i.e., the correlation that could exist among the sources seasonal productions; (ii) the installed capacity of each source; (iii) the impact of the dispatch generation over the spot price; (iv) spot price volatility in long-term; and (v) the variable cost of the generation source and operational constrains (max-min capacity).

In order to find the best market strategy which results on the lowest financial risk, simulations of candidate projects and portfolio compositions are required. Such simulations should considerer each generation unit trading their FEC independently and together in such way that the financial benefits in terms of revenue maximization and risk mitigation can be identified.

As a result, the mapping effects of projects synergism can support strategy decisions on investments in new projects or trading agreements, once the jointly effect over the portfolio is known and the financials additions are tracked.

IV. Valuation Framework

A. Optimization model

In this paper, it is proposed a business arrangement supported by an optimization model to incentivize hydro companies' inversions in wind and biomass power plants.

The optimization model objective function is the maximization of the Net Present Value (NPV) and the Conditional Value-at-Risk (CVaR) of the portfolio, subjected to the overall FEC constraint, long-term trading arrangements (sell and purchase contracts) and SMP exposures. The volume allocation in contracts is the decision variable. The model is programmed in the MS Excel platform using the Visual Basic for Applications (VBA) language and Genetic Algorithm method for optimization.

The optimization model takes into account the uncertainty of SMP and generation profiles from each source under analysis. The agent risk-aversion is represented by the CVaR measure ([16],[15]) and the search for the best solution is obtained by Genetic Algorithm technique.

One financial module linked with the quoted model permits investment analysis of each type of source, given the optimal trading strategy. This module takes into account revenues scenarios, investment costs, operational and financial expenses to evaluate each project.

The generation for Hydro, Wind and Biomass power plants are calculated as presented in (1), (2) and (3):

$$\mathrm{G}^{\mathrm{H}}_{\mathrm{m,s}} = \mathrm{FEC}^{\mathrm{H}} \cdot \mathrm{f}^{\mathrm{ERM}}_{\mathrm{m,s}} \cdot \mathrm{h}_{\mathrm{m}} \tag{1}$$

$$\mathrm{G}^{\mathrm{W}}_{\mathrm{m,s}} = \mathrm{FEC}^{\mathrm{W}} \cdot \mathrm{f}^{\mathrm{LTA,W}}_{\mathrm{m,s}} \cdot \mathrm{h}_{\mathrm{m}} \tag{2}$$

$$\mathrm{G}^{\mathrm{B}}_{\mathrm{m}} = Disp^{B}_{m} \cdot \mathrm{h}_{\mathrm{m}} \tag{3}$$

Where: $G^{H}_{m,s}$, $G^{W}_{m,s}$ and G^{B}_{m} are, respectively, Hydro, Wind and Biomass Generation [MWh] for each *m* month and *s* correspondent scenarios; FEC is the Firm Energy Certificate [MWavg]; $f_{m,s}^{ERM}$ is the ERM factor [%]; $Disp_m^B$ is the Biomass maximum available capacity generation [MWavg] in each m month; $f_{m,s}^{LTA,W}$ represents the Wind stochastic monthly production factor [%] in terms of its long term average (LTA) generation; $\mathrm{h_m}$ is the number of hours in each m month.

The Wind generation is obtained by multiplying their FEC per the percentage of the long term average (LTA) generation, for each month and scenario. Biomass generation is deterministic, running only during harvest periods.

As the hydro power plants participate in the ERM, their generation is calculated based on the ERM factor, which is defined considering the total system generation of hydro power plants ($G_{m,s}^{ERM}$) divided by the total FEC of them (FEC_m^{ERM}), as defined in (3):

$$\mathrm{f_{m,s}^{ERM}} = \frac{\mathrm{G_{m,s}^{ERM}}}{\mathrm{FEC_m^{ERM}}} \tag{3}$$

The monthly volume allocated in contract (V_m^C), as in (4), is represented in terms of the percentage (α_m) of the total portfolio FEC. This is used to find the optimal volume allocation in terms of FEC (which is the maximum amount that a company can allocated in contracts).

$$\mathrm{V_m^C} = \alpha_\mathrm{m} \cdot \mathrm{FEC} \cdot \mathrm{h_m} \tag{4}$$

The monthly accounting ($\Delta A_{m,s}$) is made ex-post, following market rules presented in the Section II. It is obtained, for each month and scenario, by the difference of the Total Portfolio Generation ($G_{m,s}^T$) and the overall volume allocated in contracts. In (5) and (6), the total generation and the monthly accounting, respectively, are presented:

$$\mathrm{G_{m,s}^T} = \mathrm{G_{m,s}^H} + \mathrm{G_{m,s}^W} + \mathrm{G_m^B} \tag{5}$$

$$\Delta\mathrm{A_{m,s}} = \mathrm{G_{m,s}^T} - \textstyle\sum_c \mathrm{V_m^C} \tag{6}$$

The financial result of the monthly accounting is evaluated by the spot price. The settlement result in the SM ($\Delta\mathrm{SM_{m,s}}$) is obtained as (7):

$$\Delta SM_{m,s} = \Delta A_{m,s} \cdot \pi_{m,s}^{SMP} \tag{7}$$

Where ($\pi_{m,s}^{SMP}$) is the spot market price [R$/MWh].

A positive accounting value means an energy volume surplus that should be sold in the SM and therefore increases the company's total revenue. On the other hand, if the accounting value is negative, the company needs to purchase a correspondent energy volume in the SM to supply the deficit.

The Monthly Revenue of a contract by quantity ($\mathrm{R_m^C}$) is a fixed part of the total revenue and is calculated as follows (8):

$$\mathrm{R_m^C} = \mathrm{V_m^C} \cdot \pi_\mathrm{m}^\mathrm{C} \cdot \mathrm{h_m} \tag{8}$$

Where $\pi_\mathrm{m}^\mathrm{C}$ is the monthly contract price [R$/MWh].

The total Monthly Net Revenue ($R_{m,s}^T$), per scenario, is obtained by the sum of contract revenue and the SM financial result, as presented in (9):

$$\mathrm{R_{m,s}^T} = \mathrm{R_m^C} + \Delta\mathrm{SM_{m,s}} \tag{9}$$

The process is ended up by calculating the expected portfolio net present value $\mathbb{E}[\mathrm{NPV}]$ for all scenarios and month, as presented in (10).

$$\mathbb{E}[\mathrm{NPV}] = \sum_{m=1}^{M}\sum_{s=1}^{S} p_s \cdot \left(\mathrm{R_{m,s}^T} - AEC_m^{B,W}\right) \cdot (1+r)^{-m} \tag{10}$$

Where: $\mathrm{p_s}$ is the probability of each scenario and AEC is the annual equivalent cost of each power plant (Biomass or Wind) or the sum of them.

Note that for this computation, investment costs are taken into account in terms of the Annual Equivalent Cost (AEC), explained in detail in next Section IV.B.

For risk measurement, we use a CVaR with confidence level of 5% worst scenarios. The calculation routine was developed in VBA language using the MS Excel platform and it was programmed to calculate the average value of the 5% lowers revenues value as the expected CVaR.

The model main conception describe in this section is illustrated in Fig. 2.

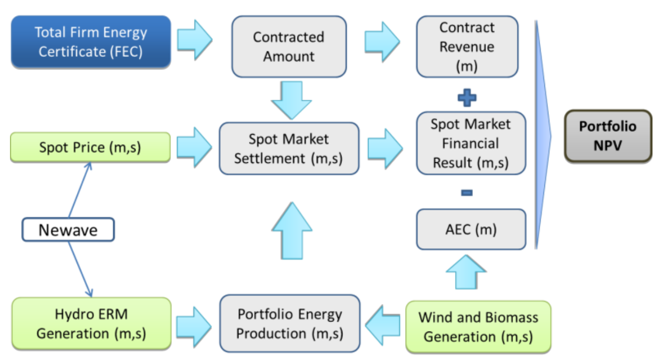

Fig. 2 The business model flowchart

B. Business model overview

The business model proposed for hydro's company (HydroCom) consists on the investment in biomass and/or wind power plants projects by creating a "Special Purpose Company" (SPC) which commercializes the energy from the new power plants with the HydroCom.

In such type of agreement (generation curve purchase contract) the HC acquires the rights on both generation and the FEC of the new power plants (SPC) by paying a fixed amount and taking the energy trading risk to itself. As a result, the investor implicitly acquires a higher credit related to the power plant associated FEC (hydro plus new plants), comparing with the maximum that could be traded under a specified risk level. And this upside can be also traded in the market.

In such agreement, there is no risk for the Biomass or Wind power plants (SPC), as they receive a fixed amount. Hence, the purchase price of the bilateral contract between Hydro

Company and the SPC should not include high risk-premium and, therefore, could be lower.

Moreover, as the business agreement mitigates production and SMP risk exposures, SPC cash-flows become more certain and stable (deterministic), and so, financing can be obtained in a lower interest rate since there is long-term contract ensuring fixed revenue.

This kind of arrangement is therefore more advantageous as the credit rating of the HydroCom is higher than it would be for the SPC alone. It is worthwhile to emphasize that the long-term contract has the same effect for bank loan purposes as the SPC in having Corporate Guarantees from the HydroCom.

A deterministic cash-flows backed up by long-term contracts also affect the project valuation as the interest rate should not contain a high risk-premium in its composition and investors tend to accept lower return in lower risky project than risky one. See more about discounted cash flows and valuation in [17] and [18].

From hydro companies' viewpoint, uncertain production of all sources and the benefits adding FEC of the new plants to the portfolio should be considered. Hydro company can trade the overall production limited by total FEC and so can allocate more energy in contracts in order to take advantage to the seasonal production and its correlation with spot market prices, as this effect reduces the financial energy trading risk.

In this study, we assume that the SPC belongs to the hydro generator company, so the contract price is assumed to be the one that provides enough return for paying investment costs in the absence of operational and financial expenses. It is important to say that if another assumption is adopted, as for instance the SPC belonging to a different investor, all the analysis that follows would remain practically the same.

The idea embedded in the business model can be simulated by means of the optimization model. We check the attractiveness of hydro investments in biomass and wind power plants considering the investment costs of these projects and based on the assumption that the overall production can be sold as a one block.

We considered that hydro power plant is already amortized and so its investment cost is not considered in our model application, only the revenue provided by trading. For the wind and biomass plants, the cash flow captures the revenues and the investment cost required to build them.

The investment cost calculated for Wind and Biomass projects are based on some physical characteristics of these plants, lifetime, debt costs, financial chronogram and the total capital expenditure (CAPEX). The interest rate (r) considered for all sources is 10% per year.

For the Wind project, the annual financial chronogram is defined as 50% in the first year of construction, 25% and 25% in the follows second and third. The project lifetime assumed 25 years and the CAPEX is considered to be 3000.00R$/kW.

For the Biomass project, the annual financial chronogram for two years of project development is defined as 75% in the first year of construction and 25% in the follow. A 20 years project lifetime is assumed and the CAPEX is considered to be 3500.00 R$/kW.

The total investment is based on the unity CAPEX and the installed capacity. CAPEX is obtained considering the capital expenditure along the construction lifetime.

The financial outlay during the construction incurs in a financial cost that is discounted by the interest rate during the construction (IRC). This cost is capitalized as future value in the initial date of the commercial plant operation. In the proposed model it is considered the same generation start-up date for all projects.

In (11) the total CAPEX considering the interest rate during the construction period is presented:

$$\mathrm{CAPEX} = \sum_{y=1}^{5} \mathrm{I_y} \cdot (1+\mathrm{r})^{(1-\mathrm{y})} \tag{11}$$

Where: y is the number of construction years until the commercial operation start up and I_y is yearly outlay.

The Annual Equivalent Cost (AEC) measure is used in order to represent the investment cost during the project's lifetime (in our case, for both wind and biomass power plants).

The AEC methodology is a function of the interest rate, power plant lifetime and total CAPEX, as presented in (13). RCF is the recovery capital factor, obtained by the interest rate (r) and the power plant lifetime (n), according to (14).

$$\mathrm{AEC} = \mathrm{CAPEX} \cdot \mathrm{RCF} \tag{13}$$

$$\mathrm{RCF} = \frac{\mathrm{i} \cdot (1+\mathrm{r})^{\mathrm{n}}}{((1+\mathrm{r})^{\mathrm{n}} - 1)} \tag{14}$$

With this approach the financial costs are uniformed distributed along the project lifetime as a monthly AEC parcel. The advantage of this method when analyzing cash flow is based on the fact that by truncating the series at the end of the economic analysis horizon (e.g. decadal) it is implicitly taking into account the residual value, which will be different for each power plant.

V. DATA AND SCENARIOS GENERATION

A. Spot Prices

As explained earlier, the Newave model provides as output the system marginal operating costs from which spot price forecast can be obtained. Then, by using historical series of hydrological conditions and setting configurations, among others, on market installed capacity expansion planning, we run the Newave model and obtained 61 series of electricity prices (or spot prices) from January 2013 to December of 2018, in a monthly basis.

B. Hydro Company dispatch

A Hydro Company (HydroCom) owning a hydro power plant with 30 MW of total installed capacity and 15 MWavg[1] of FEC is studied. The FEC of hydro power plants is obtained in a function of historical data inflows and attested by the Regulator. In our study it is assumed pre-determinate and being the sum of FEC from each hydro power plants owned by

[1] MWavg = MW average = MW per number of hours in the time horizon.

the Company. This arrangement is possible based on the centralized dispatch market rules.

Working with the same planning horizon and data from Newave, the system hydro dispatch embedding the ERM effect was simulated. As a result, 61 hydro dispatch scenarios, in terms of energy production allocation, were created.

These scenarios have the same array size of spot price given their time dependency, that is, the first scenario of spot price is dependent of the first scenario of hydro and so on.

It was assumed a weighted contracts price of 120 R$/MWh, that represents the contract price used in the analysis along the planning horizon for HydroCom selling energy to final consumers.

C. *Wind power plant generation*

As wind power plants play a low participation into the Brazilian system matrix until the recently years, it has not been inserted in the Newave model by planners, and so, its generation forecast cannot be done by it as it is for hydro and thermo dispatch.

In this sense, we generate the wind power plant energy production scenarios, in a Monte Carlo-based approach supported by a probability distribution curve, based on wind data from mesoscale models (Weather Research and Forecasting model WRF3.3, from National Center for Environmental Prediction – NCEP) correlated with history data of one region in Brazil.

The wind power plant energy production was calculated by crossing history wind data against one commercial wind turbine power curve and by simulation one wind farm of 15 MW of installed capacity and 7.55 MWavg of FEC.

D. *Biomass power plant generation*

Biomass is a cogeneration power plant that uses the sugar cane bagasse as fuel at the steam generator. This type of renewable source, as cited before, tends to generate only during certain harvest months of sugar cane, which happens in mainly Brazilian regions, usually from May to November.

During this period the maximum available generation capacity, just affected by an equivalent forced and scheduled outage rate, is produced and nothing in the rest of the period.

The regulation determines that for this type of source FEC should represent the yearly average energy production.

In practice, it means that seven months energy production are uniform distributed along twelve months, i.e., even on months when there is no physical productions, Biomass plants owners are allowed to allocated energy in contracts, but needing to buy in the spot market the correspondent amount. During the generation period, it runs more than the correspondent of its FEC, and so, the surplus is sold in spot market.

A biomass power plant with 15 MW installed capacity and 7.9 MWavg of FEC is simulated in our model and a deterministic energy production from May to November is considered.

VI. Case Study

In order to explain the business model to incentivize hydro company's inversions in wind and biomass projects, a case study is presented in this section using data and scenarios explained earlier and by applying the optimization model.

Our case is the hydro company (HydroCom) that aims at investing in biomass and/or wind power plants and decides to analyze the synergism that these SPC could bring over the existing hydro generation park.

The projects interdependencies are gone to be checked by applying our optimization model based on the conception proposed in the business model.

We worked with 9 years of planning horizon. Financial results are expressed in local currency, Real (R$)[2] and an interest rate of 10% per year is used for time discount. Scenarios are considered equally probable.

The CVaR results are in terms of the reference revenue, which represents the revenue that a company could obtain without Spot Market Price risk exposures by selling energy through public auctions, which means, at fixed price and volume, where the generation and market risks are delivered to the distributor company.

It was assumed for all cases that the Company expects an equivalent CVaR of 80% of the Annual Reference Revenue (minimum expected revenue).

All production is sold in long-term contracts (PPA) at an average price of 120.00 R$/MWh.

A. *Projects Synergism Valuation*

Using information from the HydroCom and the Biomass and Wind power plants projects, the optimization model was run to find the projects synergism value and optimal trading strategy.

Firstly, all power plants were simulated individually to find their reference revenue, NPV and the CVaR

The HydroCom was simulated by trading their forecasted energy dispatch production. The Annual Reference Revenue of the Hydro Power Plant is equal to R$15 768 000.00.

Running the model we found an optimal contracted volume allocation of 92.2% (in terms of FEC) and the CVaR achieved was R$ 12 650103.77 (80.2%), which reaches the risk condition (80%).

The Hydro results are shown in TABLE I.

TABLE I
Hydro Power Plant Results

Contracted Volume	92.2%
NPV	R$ 94 062 603.19
CVaR (% of the Reference Revenue)	80.2%

The same routine was applied for Biomass and Wind power plants individually. The Annual Reference Revenue of the Biomass Power Plant is R$ 8 320 320.00.The higher CVaR achieved for this source is equal to R$ 5 259 157.52 (63.21% of its Reference Revenue), which do not meet the risk

[2] 1 US$ = 2.05 R$ on January 2013.

condition (80%). The maximum NPV is achieved for a 66.8% of volume allocation in contract. This is affected by its generation profile, which is zero in some part of the year, as explained before. See results summarized on TABLE II.

TABLE II

Biomass Power Plant Results	
Contracted Volume	66.8%
NPV	R$ 8 359 301.89
CVaR (% of the Reference Revenue)	63.21%

For the Wind Power Plant, the Annual Reference Revenue measured is R$ 7 120 154.51. An optimum contracted volume allocation of 83% was found which gives a NPV around R$12million for a CVaR of R$ 5 700 357.24 (80%), that reaches the risk condition. The results of this case are shown in TABLE III below.

TABLE III

Wind Power Plant Results	
Contracted Volume	83.0%
NPV	R$ 11 961 555.54
CVaR (% of the Reference Revenue)	80.00%

Secondly, we repeat the same first simulations, but in this case, accounting the FEC and energy production resulted by the combination of the HydroCom plus the Biomass SPC project and by subtracting the investment costs from the total revenue expression, as shown in equation (10).

The portfolio composed by these sources reached the risk criteria, allowing a higher contracted volume compared with the individual commercialization and so, resulting in an increase in NPV (delta) around R$ 10 million. The Hydro-Biomass results are shown in TABLE IV. An expressive improvement in the risk profile can be observed, as by the combination of these sources, CVaR reached the criteria assumed (80% of Reference Revenue) while for the case of Biomass individually it was not achieved (63.21%).

TABLE IV

Hydro + Biomass Results	
Contracted Volume	93.6%
NPV	R$ 104 042 447.71
CVaR (% of the Reference Revenue)	80.00%
Delta NPV	R$ 9 .979 844.52

In a third step, we repeat the previous simulation routine for the HydroCom and Wind SPC project combined. In this approach, energy productions scenarios for both plants together were considered.

As a result of the simulation, it was found a higher contracted volume allocation (94.8%) than their individual results, which provides a delta-NPV around R$12.8million for an CVaR equivalent to 80.1% of the portfolio Reference Revenue. These results (see TABLE V) represent the benefits of their combination since risk is being minimized.

The portfolio composed by these sources reached the risk criteria (80.10%) and a higher contracted volume allocation (94.8%), if compared with the individual commercialization, resulting on a gain in the NPV about R$ 12,856,083.91. The results are shown in TABLE V.

TABLE V

Hydro + Wind Results	
Contracted Volume	94.8%
NPV	R$ 106 918 687.10
CVaR (% of the Reference Revenue)	80.10%
Delta NPV	R$ 12 856 083.91

A fourth step was done by combining HydroCom and the two projects under the same simulation routines, which results are shown in TABLE VI. In this composition, a CVaR criterion was reached and the optimum portfolio energy allocation in contracts stabilized in the level of 94.0% of total FEC.

TABLE VI

Hydro + Biomass + Wind Results	
Contracted Volume	94.4%
NPV	R$ 116 732 880.80
CVaR (% of the Reference Revenue)	80.10%
Delta NPV	R$ 22 670 277.61

TABLE VII presents the benefits that complementarity approach provides in our study case. It is shown that in each combination there is a financial benefit, especially for the case of Biomass that alone could not reach the CVaR criteria. Beyond the financial benefit, it is important to observe from previous tables that the risk profile in all cases was improved.

TABLE VII

Sources	*Individual*	*Portfolio (+ Hydro)*	*Benefits*
Biomass	R$ 8 359 301. 89	R$ 9 979 844.52	R$ 1 620 542.63
Wind	R$ 11 961 555.54	R$ 12 856 083.91	R$ 894 528.37
Wind + Biomass	R$ 20 320 857.43	R$ 22 670 277.61	R$ 2 349 420.18

VII. Conclusions

The main idea embeds in our model was applied for a Brazilian case of study, where it was used as a support decision framework to analyze the attractiveness of investments in Biomass and Wind power plants for a typical Hydro Company. It was analyzed the complementarity effect among them and over financial results (risk and return).

In all combinations, the results obtained confirm that the complementarity effect can increase generators profits and mitigate risk exposures when trading these sources together (as a block) instead of in a separately fashion.

The annual seasonality profile of these sources compared with SMP is the crux of the matter. This could be observed for the case of Biomass alone and combined with Hydro.

In conclusion, the performance results suggest the complementarity approach as an alternative for business strategy development for renewable generators companies, which suggest Hydro company's inversions in biomass and wind power plant investments.

Future study aiming at finding the optimal timing investment in each type of source, based on option-valuation and an active management of investment in projects [19] is under development.

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IX. Biographies

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