Brazilian electricity market: Problems, dilemmas and a new market design aiming to enhance flexibility while ensuring the same level of efficiency and security of supply

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Abstract: The Brazilian electricity market contains certain particularities that distinguish it from other markets. With a continental interconnected transmission system, a large and growing demand, and a total installed generation capacity around 137 GW, from which around 70% comes from hydropower plants with multiple owners coexisting in hydro cascades, this electricity market has gone through two large institutional and regulatory reforms in the last twenty years. Nevertheless, currently the conciliation between the commercial commitments of the market participants and the physical dispatch is not smooth. There is a lack of "trading opportunities" to encourage participants to comply with their contracts. Moreover, the Brazilian short-term market acts as a mechanism to settle differences rather than a true market and, neither the short-term price nor the dispatch schedule is determined by the market. This paper discusses these problems, brings out some dilemmas that should be examined in order to implement a more market-oriented approach, and proposes a new market design to overcome these issues. The proposed market design is based on the concept of energy right accounts as virtual reservoirs and aims at enhancing the flexibility to enable market participants to comply with their contracts, while still ensuring the efficient use of the energy resources and maintaining the current security supply level.

Keywords: Flexibility to comply contracts. Energy resources efficiency. Security supply. Virtual reservoir model.

1. INTRODUCTION

Electricity industries have evolved from vertically integrated utilities to more decentralized structures and competitive electricity markets in order to ensure fair competition, higher efficiency, declining pricesand reliability of operation. With a continental interconnected transmission system, a large and growing demand, a total generation installed capacity around 135 GW, from which around 70% comes from hydropower plants, this Brazilian electricity market has gone through two large institutional and regulatory reforms in the last 20 years. As a result, this electricity market has certain particularities that contribute to considerably distinguish it from other markets, such as the Mechanism for Reallocation of Energy and the Seasonalization process.

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The first reform promoted a transition from the vertical integrated utility structure to a market where agents could freely negotiate contracts. Besides that, the quantities that were traded by contracts have been reduced whereas more trading in the short-term market was encouraged (ARANGO et. al., 2006). During this time, Brazil had a decentralized energy planning, but with an indicative energy planning conducted by the

National Council for Energy Policy (CNPE). Then, in 2001 Brazil experienced a major supply crisis, which led to an aggressive energy rationing from June 2001 to February 2002. The 2001/2002 energy rationing had major economic and political impacts and encompassed about 80% of population, GDP and electricity consumption (MAURER et. al., 2005).

Driven by the mentioned rationing, the second reform took place basically pushed Brazil to a structure corresponding to the single buyer model, but preserving some competition features in the retail market. In practice, a new regulatory framework (introduced by Law 10848/2004) was implemented in 2004 brought backsome old fundaments/principles and added new guidelines:

a) Reintroduction of the long-term centralized planning conducted by the federal government to address the security of supply. Thus, the expansion of the system doesn't rely on a market-based economy;
b) Competition through public auctions according to the single buyer model. The main target of this scheme is to provide affordable tariffs to the growing economy;
c) Implementation of long-term contracts (PPAs) with availability of payment. The goal was to promote the installation of thermal power plants;
d) Requirement that consumers must be fully supplied by energy and power purchase contracts, and all contracts must be registered with the Brazilian market operator (CCEE);
e) Requirement that sellers must have enough capacity when selling energy and power to entirely ensure their contracts; and
f) Restructuring of the commercialization processes by creation of two contracting environments: the *ACR* – Regulated Contracting Environment and the *ACL* – Free Contracting Environment.

Both the implementation of PPAs with availability of payment (item C) and a mandatory bilateral contracting scheme (item D) with physical backing(item E) were adopted to guarantee the return of investments and address the security of supply, since this was appointed as one of the reasons of the above mentioned rationing.

Regarding item D, it is relevant to reinforce that the electricity demand of both distribution utilities (on behalf of captive consumers) and free consumers must ensure the compliance of 100% of their consumptions by energy and power purchase bilateral contracts (Decree 5163/2004, art 2º, items II and III). Otherwise, specified penalties will be applied to them. As a result, this legal provision definitely imposes a bottleneck on the trading of electricity into the short-term market.

Concerning item E, it means that all electricity sold by sellers should be 100% physically backed (Decree 5163/2004, art 2º, item I). This "physical coverage for sale" consists of what is known as "physical guarantee" of the power plants. The physical guarantee corresponds to the maximum amounts of energy associated with each power plant project. Relating to hydros, physical guarantee corresponds to the maximum energy production that can be maintained almost continuously over the years, simulating the occurrence of thousands of inflow sequences created statistically, and assuming a certain risk of not feeding the load (ANEEL, 2013). To sum up, the physical guarantee, which is defined by the Ministry of Mines and Energy (MME), has the value of a certificate that determines the amount of energy that each power plant can trade.

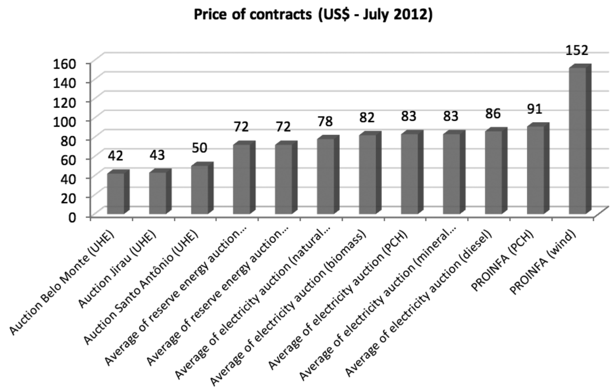
2. FROM MARKET RESULTS TO PHYSICAL OPERATION OF THE POWER SYSTEM

For end consumers, the Brazilian electricity market operates in two ways. It operates under competition in the retail market, named *ACL*, for those eligible consumers that fit in the characteristic of free consumers or special consumers, and it works according to the single buyer model structure, entitled *ACR*, for the final consumers that are not free to choose their supplier.

In the *ACR,* prices are determined by national public auctions. Differently, in the *ACL* prices are freely negotiated between buyers and sellers through a non-organized market like OTC, where a lot of traders can mediate the deal between consumers and producers, or through emerging private power exchanges. Additionally, there is also the short-term market, in Brazil known as *MCP*, which is designed to account for and settle the differences between the contracted energy amounts and the generated/consumed energy.

There are several kinds of national public auctions. Some of them are implemented to buy "new energy", i.e. electricity that will be produced by power plants that still have to be built, while others aim at buying electricity from power plants already under operation. Moreover, there are also specific auctions designed to buy electricity only from renewable energy sources (such as wind, PV, biomass and small hydros), to raise the level of security of supply (reserve energy auction), and to promote the feasibility of relevant and structuring projects.

Figure 1 shows average prices of ACR auctions carried out between 2004 and 2012 by energy source.



Then, all contracts must be registered at the market operator (CCEE) in order to be considered in the settlement process of the *MCP*. Additionally, when a power plant becomes available for operation, the CCEE considers the associated physical guarantee available to besettled. Then, regularly in December of every year, market participants can perform a seasonal adjustment of the contracted energy and of the physical guarantee to be applied for the entire next year (CCEE, 2012). This process is called "seasonalization" which, in other words, it allows distributing the total annual amount in monthly MWh packages. Besides the seasonalization, the MWh are also allocated in three load steps, in a process known as "modulation".

The power plants are then dispatched by the system operator (ONS) in order to optimize the hydrothermal system and use energy resources in an efficient way. The dispatch is performed without considering the amount of the contracted energy and physical guarantee. Instead of a market-based approach, the dispatch is defined based on the solution of aminimum operational cost problem that seeks for a trade-off between saving water now and using thermal fuel (if the expectation of inflows is low) or using water now and saving thermal fuel (if the expectation of inflows is favourable).Furthermore, concerning the coordination of the operation, since there are a lot of cascades of hydro stations with different owners, it is also important to consider the use of the potential energy stored in the reservoirs installed in the same water basin.

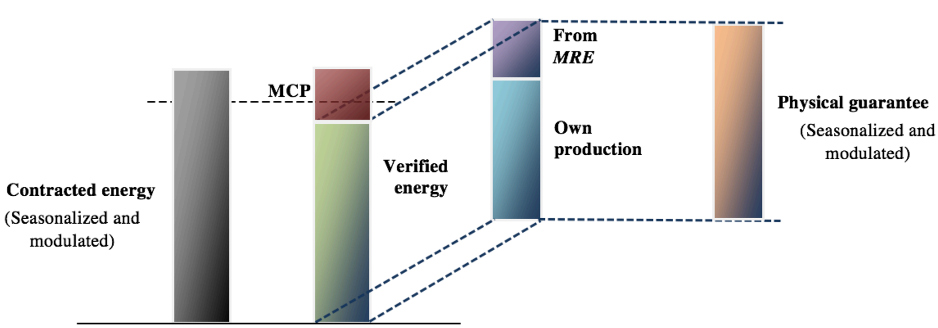
As a consequence, the dispatch is centralized and the optimal dispatch problem is currently solved basically through a stochastic dynamic programming software package called NEWAVE together with a linear programming software called DECOMP.The two main outputs of these two packages are as follows: the dispatch schedule of the power plants under operation and connected to the National Interconnected System; and the Brazilian short-term market prices, well-known as *PLD*(Price of the Differences Settlement). Both of them are established weekly for each load step of the day.

Because the dispatch is performed by the ISO in a centralized way and it decides the market participants' outputs without considering their ex-ante contracted energy, and once generators need to sustain their contracts by delivering the electricity committed through contracts, there is in Brazil a mechanism called Mechanism for Reallocation of Energy (*MRE*). The *MRE* is applied to hydros that are committed to deliver a certain amount of electricity (MWh) during a specific period at a pre-defined price. The goal of this mechanism is to cover the risk of generators having to buy electricity in the short-term market at *PLD* to fill in the amount of energy committed in their contracts.

All generators receive their contractual payment substantially because they sell the "physical guarantee assigned to them", and not because they sell the "actual electricity produced by them". Then, in each accounting period, the *MRE* reallocates energy, transferring the surplus generated from those that produce beyond their physical guarantee to those that produce below. So, if the own production of a hydro station is less than its physical guarantee (which is calculated in long term to represent the amount of electricity that can be continuously produced), this station will receive energy from stations that produced more.

The short-term market (also called *MCP*) is used to make all settlements. Once all closed contracts have to be recorded in CCEE, the CCEE measures the amounts that were actually produced / consumed by each agent. After applying the *MRE*, the differences between contracted energy and the verified energy are accounted for, and the exposed positions are valued at the *PLD*. Their own production (power plants just follow the dispatch order of the ISO) plus the energy allocated from the *MRE* (which depends on the seasonalized physical guarantee) is equal to the verified energy. Then, the verified energy is compared with the contracted energy, and the resulting difference is settled in the *MCP* at *PLD*. This settlement process, as illustrated in Figure 1, is performed on a monthly basis.

Figure 2 – Traded energy in MCP: negative exposition.



To bring this section to a close, Table 1 shows a number of types of contracts from both the *ACR* and the *ACL*, and briefly explains how the dispatch procedure is carry out by the system operator (ONS) and the settlement of exposed positions performed by the market operator (CCEE).

Table 1 – The ACR and ACL markets, the dispatch procedure and the MCP.

<table>
<tr><th>ACR – Regulated Contracting Environment</th><th>ACL – Free Contracting Environment</th><th>ISO dispatch procedure</th><th>Brazilian short-term market (MCP)</th></tr>
<tr><td colspan="2">Types of contracts involved:</td><td>How generators are dispatched by ONS?</td><td>How exposed positions are settled by CCEE?</td></tr>
<tr><td>· CCEAR (Contract for Electricity Trading in the Regulated Environment)</td><td>· CCEAL (Contract for Electricity Trading in the Free Environment)</td><td rowspan="7">· ISO knows the installed capacity, availability, and fuel cost of generators.
· ISO also knows the predicted consumption due distribution companies' monthly declarations.
· ISO forecasts the weather to stipulate rivers inflows.
· It is run software based on stochastic dynamic and linear programming to establish the dispatch schedule and the PLD.</td><td rowspan="7">· All closed contracts (in both ACR and ACL) have to be recorded in CCEE.
· CCEE performs measurements of the amounts actually produced / consumed by each agent.
· MRE is applied for participants of this mechanism.
· Differences between contracted energy and the verified energy are accounted.
· Exposed positions are valued by PLD.</td></tr>
<tr><td colspan="2">· CER (Contract for Reserve Energy), signed between CCEE and sellers agents</td></tr>
<tr><td colspan="2">· CONUER (Contract for Use Reserve Energy), signed between CCEE and consumption agents</td></tr>
<tr><td>· Contracts for Distributed Generation</td><td rowspan="4">· CCEI (Contract for Purchase Encouraged Electricity)</td></tr>
<tr><td>· Contracts of Adjustments</td></tr>
<tr><td>· Contracts of PROINFA (Program of Incentives for Alternative Electricity Sources)</td></tr>
<tr><td>· Contracts of Itaipu Hydropower Plant</td></tr>
</table>

3. PROBLEMS

Not withstanding, there are some problems that arise from this market design, which are discussed below.

3.1 Problem 1: The conciliation between the commercial commitments of the market participants and the physical dispatch is not smooth

In order to trade both energy and power, several markets have emerged with the market liberalization: day-ahead, intraday, balancing, forward, future and options markets. However, when all these markets are operating together it should have a concern related with the coordination conditions between them. For instance, it is possible that weak links exist between forward and short-term markets, as well as between the distinct markets for electricity and reserves.

Wilson (1999) addresses this concern bringing the idea of the "sequence of markets", which means that a rich sequence of forward markets (e.g. long-forward, day-ahead, hour-ahead, spot) approximates a single complete market. Thus, the "incompleteness of the market" can be addressed by repeated trading of a few simple contracts in order to allow contingent contracts to come close to a complete market. As a result, frequent trading opportunities enhance the completeness of the entire market.

In Brazil there is no balancing market; neither intraday or day-ahead options, nor future markets. Instead of that, there is an annual "window" to monthly distribute the physical guarantee and the contracted energy (via the seasonalization process already described). The centralized dispatch is carried out by the ISO without considering the signed contracts, and generators are not allowed to, in the medium and the short-term, decide their own generation in order to uphold their contracts. As shown in Figure 3, this can significantly expose them to the risk of having to buy electricity in the *MCP* at the high volatile *PLD* in order to deliver the energy committed in their contracts.

Figure 3 – Traded energy in MCP: negative exposition.

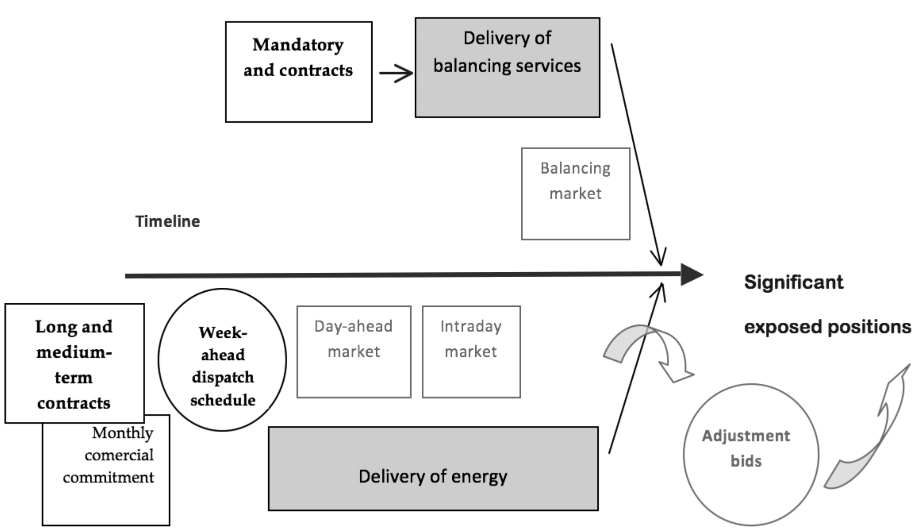


Table 2 – Conciliation between physical dispatch and commercial commitments

Electricity industry structures	Contracts between market participants	System operator dispatch	Conciliation between dispatch schedule and contracted positions	Costs/prices passed on to tariff of final consumers
Vertically integrated utility	Without contracts (command and control management)	System operator dispatches considering the minimal operational cost, since it a priori knows each marginal cost.	There aren't electricity market and contracts involved, so there isn't need for conciliation.	Consumers pay for the cost of each MWh produced based on cost of service regulation.
Single buyer model (Brazilian case)	Long-term contracts (PPA) via public auctions in the *ACR* Ancillary services are provided by grid codes and by contracting for reactive energy Medium-term contracts in the *ACL*	Minimization of the operation cost through the tight pool approach. ISO doesn't consider the amount of electricity sold or bought through contracts (it just uses the price from the public auction to perform the merit order). Generators are not active in this central-dispatch procedure.	It is expected that participants comply with their closed contracts by their own production. However, it is the ISO who decides their outputs without considering their contracted amounts. So, it is needed a mechanism (the *MRE*) to share the associated risk.	Prices of the PPAs, which have two components: energy payment and availability payment; PS: Participants settle imbalances.
Wholesale and retail competition (like Texas in 2000)	Bilateral physical contracts Balancing market Financial forward contracts	Minimization of the difference between the closed contract and the real production. In short-term, generators submit notifications to the ISO/TSO, which are expected to be equal to contracted positions. ISO/TSO dispatches considering these notifications. Generators are active through a self-dispatch procedure.	ISO/TSO tries to dispatch the exact amount of the physical notifications, i.e. his goal is to minimize the suppliers' exposed position.	Prices coming from the bilateral contracts and balancing market; PS: Participants settle financial contracts and imbalances.
Wholesale and retail competition (like some USA states, and European countries)	Short-term markets, as day-ahead and intraday Balancing market Financial and physical forward contracts	Minimization of the operation cost through the loose pool approach. Sellers and buyers submit their bids. Power Exchange dispatches considering the successful bids. Generators influence, through their bids, the dispatch schedule.	ISO/TSO implements technical adjustments to enforce violated constraints.	Price of the short-term markets and balancing market; PS: Participants settle financial contracts and imbalances.

The issue regarding the conciliation between the commercial commitments of the market participants and the physical dispatch of the power system becomes more evident when the Brazilian electricity market is compared with other electricity markets around the world. Thus, to bring a broader outlook to this problem, Table 2 presents a helpful comparison.

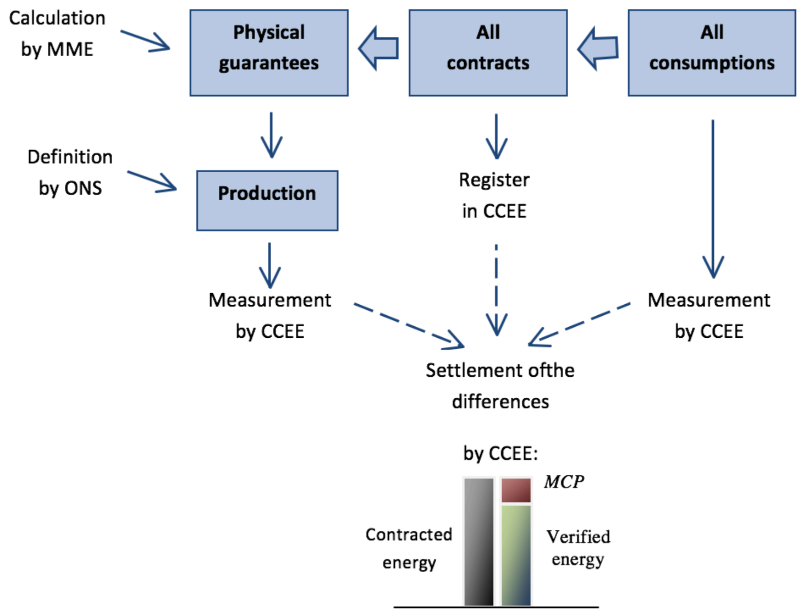
On balance, in markets as day-ahead, intraday and balancing markets, players are more active in the definition of the merit order on a day-by-day basis and so they have more opportunities to cover their positions engaged with bilateral contracts. This fact can be viewed as a higher completeness of the market when compared with a market where participants close their positions by long-term contracts.

3.2 Problem 2: The Brazilian short-term market is a mechanism to settle differences rather than a market

The *MCP* takes place after the dispatch of the ISO. Furthermore, unlike other market designs addressed in Table 2, the Brazilian short-term market is not the marketplace where generators are active through a self-dispatch procedure, orwhere generators influence the dispatch through their bids. Ultimately, the Brazilian short-term market is not an environment where market participants can engage in short-term trades on their own account. Neither party arrives at some point to make any short-term declaration of intent. Moreover, the price that values these transactions (*PLD*) is not a result of the interaction of market participants, but comes from the application of a chain of software models, which is run by a third party entity. In summary, it would be a short-term market if, in this environment, market participants meet with each other in order to negotiate electricity and close agreements in the short-term according to their own will.

So, contrasting with other short-term markets, the *MCP* is a mechanism to settle differences between the amounts of electricity committed by contracts and those amounts of electricity that each agent ends up providing / receiving. These differences, illustrated in the Figure 2, must be automatically purchased or sold in the *MCP*. Figure 4 synthesizes relevant points related with this issue. Once all consumption has to be ex-ante contracted and contracts have to be physically backed, the Brazilian market was conceived to have no mismatches between the computed long-term production (i.e. the physical guarantees) and the foreseen consumptions. Nonetheless, it is the responsibility of the *MCP* to deal with the individual differences that may occur due to the mismatch between the monthly verified and contracted energy of each market participant.

Figure 4 – An overview of the commercialization processes.



3.3 Problem3: The codes associated to the chain of software used to run the centralized dispatch are under intellectual property rights.

As previously indicated, it is not the market through the interaction between its participants that determines the electricity short-term market price and the dispatch schedule. Basically, since historically more than 80% of the electricity produced in Brazil comes from hydropower plants, this is performed by two computational programs (NEWAVE and DECOMP) that value the present electricity cost considering, among other variables, future scenarios of water inflows.

Therefore, inconsistencies in these algorithms have a huge impact within the entire sector, and the confidence of the market can be affected. Unfortunately, during 2007 and 2011, relevant problems related with inconsistencies in these models were detected. These problems caused a large impact on the electricity sector, not to mention transparency problems since the source codes have intellectual property rights and, therefore, they are unknown by the market participants and authorities, inducing some instability in the Brazilian electricity sector.

4. DILEMMAS

A solution typically adopted in other markets is the employment of a more market-oriented approach. This market approach could enable all generators to offer, in short-term, quantity and price bids, which would be used to set the market positions and, consequently, substitute the seasonalization process and the MRE. As a result, the short-term market price would be based on the interaction between market participants. Nevertheless, there are some dilemmas to be faced, especially if considering a power system with a large share of hydros.

4.1 Dilemma 1: Efficiency of energy resources

The Brazilian and the New Zealand power systems are quite similar in terms of the importance of hydro generation. Both nowadays have around 60% of the electricity produced coming from hydropower plants (New Zealand System Operator, 2014) (ONS 2014a). However, in New Zealand generators make offers and are dispatched each half hour in a compulsory market pool. Thus, the offer stacks they submit are the only mechanism that they have to sculpt a varying generation plan to comply with their own constraints over the day.

Additionally, in New Zealand a single generation company operates the vast majority of the hydros in the same river, and there is a block dispatch scheme that allows generators to rearrange the dispatch amongst their stations on the river-chain, as long the total energy delivered is the same as the required stations are geographically close. Nonetheless, an empirical study performed by Philpott et al. (2010) quantified some production efficiency losses of this market.

These authors developed a centrally-planned model in order to compare New Zealand market outcomes with a counterfactual central plan. The results show that theyearly centrally-planned policy incurs less fuel cost than the market approach. For 2005, 2006 and 2007, the saved fuel costs are, respectively, 16.0%, 13.4%, and 14.6% of the total generation cost. In conclusion, the main source of the inefficiency pointed out by these authors relies on the fact that the New Zealand decentralized dispatch is essentially an instantaneous process and the inter-temporal features of river chain operations are not represented in the single-period market clearing mechanism.

Putting into perspective the dichotomy between a centralized dispatch (based on hierarchy) and a decentralized one (based on a market solution), it becomes clear how important if the coordination of the use of the water stored in the reservoirs in order to safeguard the efficiency of using the energy resources. Moreover, the presence of several owners in the hydro cascades, i.e. to take advantage of the all potential energy stored in the cascade.

A decentralised dispatch, e.g. a scheme of bids in a market pool, can essentially be an instantaneous process and the inter-temporal features of river chain operations cannot be entirely represented, if a pure single-period market clearing mechanism is adopted. Moreover, the presence of several owners of the hydro cascades, as is the case in Brazil, endorses a market design based on a centralised dispatch.

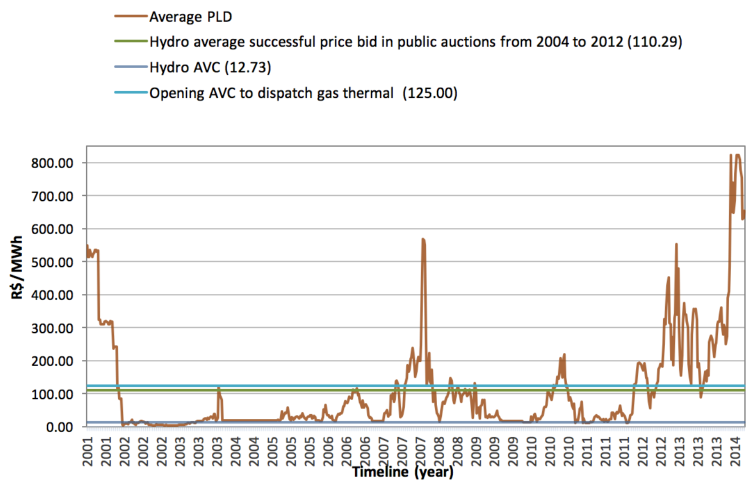
4.2 Dilemma 2: Security of supply

Concerning the ability of the market to ensure sufficient capacity to meet future demand, it must be noted that generation companies will only invest in new power plants if they expect to recover their total costs (both variable and fixed costs). Thus, considering a Brazilian electricity market entirely reliant upon a short-term market, the following question arises: Will the response of generators regarding the short-term market prices come in the form of new installed capacity?

The Brazilian short-term market price, *PLD* is calculated for four submarkets (South, Southeast/Midwest, Northeast and North) and is set on a weekly basis for three load steps (heavy, medium and light). Regarding this issue, Figure 5 presents: the *PLD* curve (CCEE, 2014a); the hydro average successful price bid that came from public auctions (110.29 R$/MWh) (CCEE, 2014b); the hydro Average Variable Cost - AVC (12.73 R$/MWh); and the AVC starting point to dispatch the gas thermal power plants (125 R$/MWh) (ONS, 2014b). It is worth mentioning that the price bid in public auctions is the PPA contract price. Thus, the value 110.29 R$/MWh can be perceived as the hydro Average Total Cost (ATC), once at this level it is expected to recover both the Variable Cost (VC) and the Fixed Cost (FC).

The Brazilian short-term market has been in existence for about fifteen years. For the time being, the *PLD* has an average value of 109 R$/MWh. Therefore, it is close to the aforementioned 110.29. Nevertheless, it should be noted that, since the beginning of the PLD historical data, Brazil endured two large energy crises (in 2001-2002 and in 2013-2014) that caused the *PLD* to remain in extreme levels for long periods. Besides, these so high price levels were not expected in a country that traditionally produces electricity based on hydropower.

Figure 5 – PLD historic data: from 2001 to 2014.



Regardless, supposing that from now on more thermal stations are included in the dispatch and, thus, the *PLD* would be greater, the question is will the *PLD* curves hape be a barrier to new investment? So, the analysis rests on the *PLD* volatility. The *PLD* standard deviation of the entire set of data is around 160 R$/MWh. With an average of 109 R$/MWh, a standard deviation equal to 160 imposes a big risk to the health of the business, especially regarding the stability of the cash flow.

Finally, it is recognised that a capacity mechanism is needed in order to provide enough incentives to ensure the security of supply. Nowadays, this concern is addressed via both the contracting scheme where the demand must be fully contracted ex-ante and contracts physically backed, and the ISO dispatch, either through the mechanism of risk aversion in the software package, or through a dispatch according to the merit order authorised by CMSE, the entity that monitors the supply adequacy in the country.

4.3 Dilemma 3: Flexibility to sustain contracts

Not withstanding the trend in favor of maintaining the current ISO central dispatch in order to ensure the efficiency in the use of the energy resources and the security of supply, it is missing in the electricity market design some flexibility for hydros to better address their risk of exposition in the short-term market according to their own risk perception and strategy.

There is one unique "window" (in December) to define the (monthly) amount of the physical guarantee that will up hold the contracts. Taking into account the market completeness analysis, there is a lack of "trading opportunities". Moreover, generators operate their power plants just following the amount of production defined by the ISO, and the

MRE is automatically performed, which imposes a kind of "strait jacket" to the market participants.Taking a closer look at the seasonalization process and at *MRE*, the following situation brings to light a weakness of this market design.

Every time that *PLD* is high, there are more dispatched thermal stations and less hydro dispatched units. Thermal power plants are typically contracted in the "modality for availability", so they receive an availability payment and an additional remuneration for each MWh produced. Nevertheless, hydros are normally contracted in the "modality for quantity", i.e. they are committed to deliver a certain amount of electricity (MWh) at a pre-defined price, and the difference between the contracted energy and the verified energy must be automatically bought or sold in the *MCP* at the *PLD*.

Depending on the amount of thermal dispatch, hydros can be displaced in such a way that the total production in the *MRE* will not be larger or equal than the total physical guarantee of the *MRE*'s hydros. As a result, *MRE* will not have the extra energy to be shared among its participants. Unlike, an adjustment factor will be applied to with draw a fraction from the seasonalized physical guarantee. Extending this reasoning to occasions of water scarcity, a large decrease in the seasonalized physical guarantee of all hydros participants of the *MRE* represents a widespread negative exposed position for these hydros.

Admitting that this situation will last for some months and that aplenty of hydro station shave to buy energy in the *MCP* at a very high *PLD*, this can seriously affect their cash flow. Unluckily, Brazil is currently facing a similar situation. Due to an unusual rainfall cycle that has lasted since 2012, the power system has a widespread water shortage, a large thermal dispatch and PLD constantly reaching the ceiling price in all submarkets.

If each hydro would decide its own production, the reservoir management would be on their own. However, in the Brazilian case, the decisions regarding each production level, and consequently the amount of energy to be stored in the reservoirs are taken by a third party, the ISO. Nonetheless, water shortage risk is assumed by hydros, once the MRE doesn't cover it. It would therefore be more consistent to follow (IEA, 2005): to structure the framework of incentives such that risks are allocated to those who take the decisions and who hold the responsibility for taking them into account.

5. A NEW MARKET DESIGN

Focused on improving the flexibility to enable market participants to comply with their contracts, while still ensuring the efficient use of the energy resources and maintaining the current security of supply level, and partially considering the proposal of the Revitalization Committee of the Electricity Sector (2002), a new market design was developed to be applied to the Brazilian power systems. Based on the concept of energy right accounts as virtual reservoirs, in this new design each hydro is modeled as an agent that has a virtual reservoir representing how much energy is virtually stored in his hydro plant. Hereafter, for each accounting period, each account is fed by the fraction of the total natural affluent energy that flowed to the hydro cascade proportional to the hydro's physical guarantee. Then, the following sequence of events is adopted:

1º The system operator continues his work as it is currently done (running NEWAVE, DECOMP as well as other software, procedures and scheme), and defines the amount of generation for each power plant. This means that it maintains its responsibility in terms of defining the physical dispatch optimizing the use of the resources, dispatching the hydro and thermal units;

2º The "remaining demand" is obtained for each dispatch period. This remaining demand is equal to the total demand minus the total dispatch allocated to the thermal power plants. This difference is the total demand to be supplied by hydros;

3º A bid based hydro short-term market is established for the remaining demand. In this market, hydros have the opportunity to withstand their bilateral commercial commitments while trying to make successful bids. The result of this market is a virtual dispatch with financial settlement purposes. To do that, hydro agents can offer bids considering a price between zero and a ceiling price (e.g. the cost of the cheaper thermal power plant dispatched in this period) and a quantity available within his account;

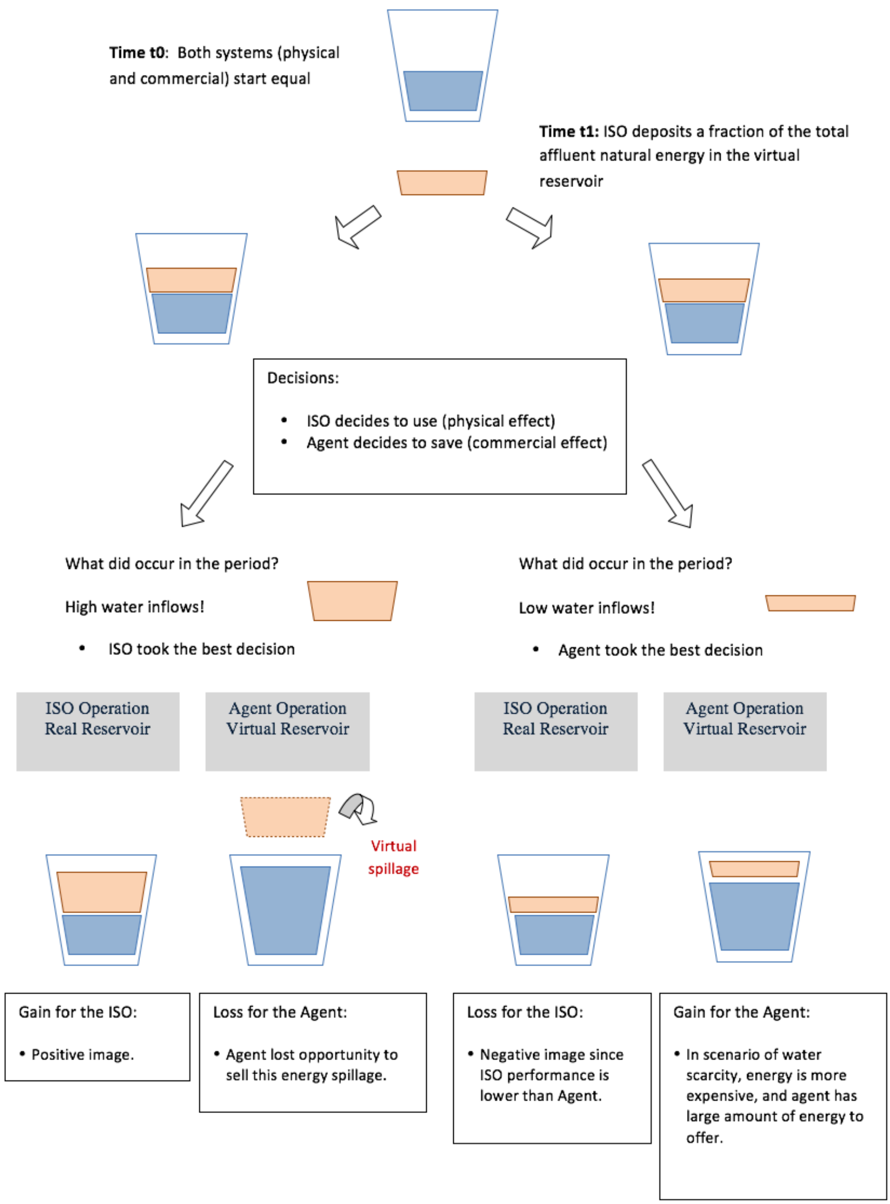
4º The final short-term price is calculated as a weighted average considering the most expensive successful hydro price bid and the variable cost of the last non-hydro resource dispatched by the ISO.

In this new market design, as can be observed in Figure 6, two worlds would coexist: the real one, associated with the power system considering physical effects, and where the ISO runs the dispatch in a centralized way; and the virtual one, related to the settlement system and with commercial effects, and where hydro agents participate in a short-term market. Both worlds simultaneously operate, and the link between them is the total affluent natural energy that flowed along the hydro cascade in each accounting period. At last, the settlement process will occur considering the successful quantity bid of each participant, and the exposed position will be valued by the new final short-term price.

Through this market design, agents would be responsible for deciding, in commercial terms, how much they want to withdraw from their virtual reservoirs to meet their contracts. To do that, their bids have to be accepted in an auction that will be performed as a day-ahead market. In doing so, each generator has the opportunity to manage his contracts more efficiently, without affecting the real operation of the physical system.

Furthermore, this model promotes a monitoring of the ISO performance based on comparisons between his decisions (the physical world) and the market participants decisions (virtual world). To illustrate this issue, Figure 6 presents a scheme regarding the decision-making process in this new market design.

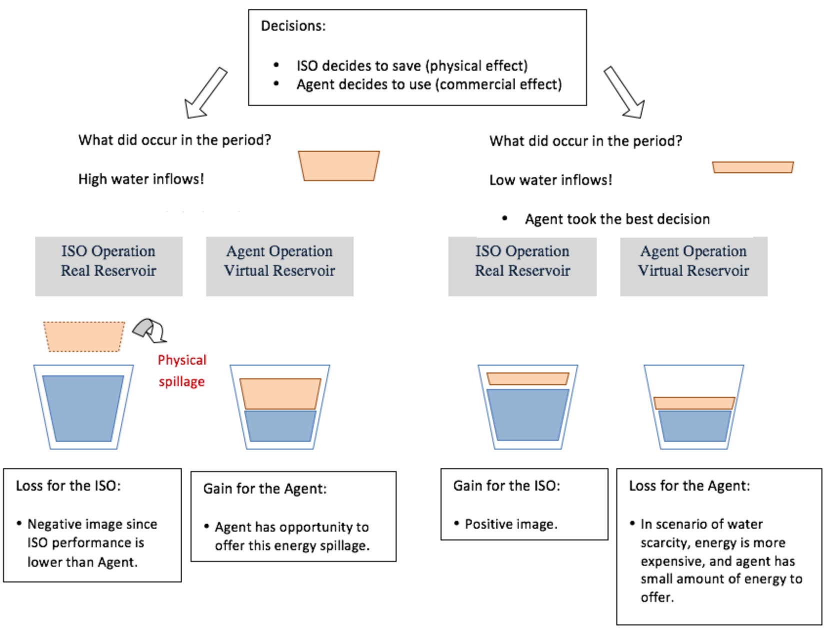
Figure 6 – Decision making process: ISO decides to use water; agent decides to save water.



In Figure 7 the ISO decided to use water, while the generation agent decided to save it. As can be observed, if the ISO took the best decision he will have a positive image and the agent will loss opportunities to offer the spilled energy; otherwise, the ISO will have a negative image and agent will have the opportunity to sell energy that he saved when there is a water scarcity and, thus, the energy price is higher.

When these decisions are reversed (ISO decided to save and the agent to use), instead of having a virtual spillage, as shown in Figure 7, it can happen a physical spillage. However, the same reasoning regarding gains and losses is applied.

Figure 7 – Decision making process: ISO decides to save water; agent decides to use water.



At the end of this process, the prices no longer result primarily from a chain of computational models that may eventually present problems related with inconsistencies and transparency, but they can be obtained through the combination of thermal costs originated from the ISO dispatch and the short-term market price arising from the liberalized hydro short-term market. A mix of centralized dispatch and market based on bids can, therefore, increase the confidence of the market participants and improve the transparency and regulatory stability of the power sector.

Furthermore, with both the physical and virtual dispatch operating in parallel, it is possible to promote a monitoring of the ISO performance based on comparisons of decisions, namely the ISO decisions *versus* agents decisions.

Finally, this market design maintains the same levels of the previously mentioned efficiency and security, while increases the level of flexibility of the agents' commercial aspects. This flexibility can be achieved by replacing the *MRE* and the seasonalization process by a virtual reservoir model. As a consequence, the management of (virtual) reservoirs is under the responsibility of each hydro, which could (virtually) save water according to their own risk perception. In doing so, the operation of the physical system is not affected, ensuring the efficiency of the hydro cascade and maintaining the current level of the security of supply.

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