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The Real Possibility of Competitive Generation Markets in Hydro Systems—The Case of Brazil

*Antonio Estache
and Martin
Rodriguez-
Pardina*

Brazil's electricity sector, one of the largest in the world, is made up of more than sixty-five, mostly vertically integrated, federally and state-owned monopolies. The most pressing problems in the sector are excessive operational costs—estimated to be 20 to 30 percent too high on average—and large investment needs in the face of rapidly growing demand and very limited public finance. Both of these problems can be addressed through more competition and more private participation in the sector. Competition would lower costs and thus reduce the need for politically costly tariff increases to finance investment needs. And opening the sector to private participation and ensuring competition under transparent, equitable operating and pricing rules should generate the resources to meet investment needs.

While the shape of reform in the sector has yet to be finalized, there is a consensus among federal and state policymakers and key operators that the sector's potentially competitive segments—generation and supply—should be separated from its natural monopoly segments—transmission and distribution—and awarded as concessions or sold to private investors. There is also a consensus that there should be a single, publicly owned transmission entity, that dispatch should be centralized, and that prices should reflect opportunity costs and cross-subsidies should thus be unraveled. But formidable political challenges remain—not the least of which, given the complex web of ownership in the sector, is getting overall agreement on the details between the federal government and the states. There are important technical challenges too. One set of challenges relates to competi-

tive generation. The proposed unbundling of the sector parallels the reform model in Argentina, Chile, Colombia, and the United Kingdom. But while these countries have thermal-based systems, Brazil's electricity sector is largely hydro-based, requiring a different set of rules to make competition work in the wholesale generation market. There are two main issues. First, to ensure open entry and the long-term viability of competition in the electricity sector, the government must figure out how to competitively allocate water rights. Second, to provide incentives for investing in generating capacity, a pricing system must be put in place that will ensure recovery of the high sunk capital costs characteristic of hydro systems.

This Note describes one consistent approach, using incentive-based organization and regulation, for overcoming the technical challenges to effective competition in the generation market.

Open entry

The most pressing requirement for ensuring the long-run viability of competition in hydro generation is to figure out how to allocate and enforce water rights. In Brazil, the government owns all water rights. Because monopolistic ownership of primary energy sources allows the owner to appropriate the rents of all downstream activities, there should be competition for the right to use these water rights rather than for the right to own or control them. When a power generation company owns the water rights, this constitutes an entry barrier to new generators, because when analyzing the construction of a new plant, the incumbent will





internalize the impact on its existing plants. Thus, one mistake that must be avoided is selling the water rights as part of the existing companies, as was done in Chile.

Public bidding seems to be the best approach to franchising water use rights, and Brazil has already advanced in this direction through its public service concessions law, which requires public bidding for all hydropower potential of more than 10 megawatts. The law accepts either of two mechanisms as the basis for awarding bids to achieve efficiency in the allocation of water resources—the lowest asking price for energy, which allows different prices for different plants, and the highest payment for water use, which leads to a single price set by the market. But to optimize competition, Brazil should choose the mechanism based on the highest payment for water use because it results in a single price for all plants. At the same time, it should allow no preferences for or discrimination against different types of bidders—including generating companies, industrial self-generators, and distribution companies.

An important benefit of such competition is that it allows the market to decide when, how much, and what type of generation is needed. In Argentina and the United Kingdom, for example, the increasing share of gas generation, which involves lower capital costs and shorter construction time, is probably an outcome of granting free entry to the generation market. This diversification of primary energy sources can help reduce the expansion costs of a rapidly growing system, and new energy sources should be allowed to compete on equal footing with hydro generation.

Cost recovery

Optimal dispatch in a hydro system does not depend only on the demand and the available capacity at a particular moment (as in the economic merit order dispatch conceived for purely thermal systems). It also has to take into account the intertemporal problem posed by water storage—whether to use water now or save it for

future use. Water in a reservoir has an opportunity cost set by future prices (or costs) and the probability of overflow (once the reservoir is full). When storage capacity is full, and for run-of-river power producers, the opportunity costs are nil and water must be run through the turbines or spilled. Thus, to determine the optimal use of water today requires simulating the evolution of the system in the future. The length of the simulation period depends on the storage capacity of the system—in Brazil, the horizon for simulation is five years. The difficulty of projecting demand patterns, rainfall, equipment failures, and the like for such a long period makes the problem of hydro dispatch a very complex one to address through market mechanisms.

Another complicating factor in the Brazilian hydro system and in many other hydro systems is that there are often several generating units on a single river, so that the generation capacity of one plant is influenced by the storage capacity of upstream generators. All this implies a strong interdependence of production costs across generators—which is why it is a good idea to have central dispatch for each interconnected system.¹

The predominance of hydro in the Brazilian electricity sector means that marginal prices can be very low over long periods, hindering the timely recovery of capital costs. Pricing rules such as those in Argentina, Chile, and the United Kingdom, which set energy prices at cost (or bid) of the marginal plant, would result in highly volatile prices in Brazil, ranging from zero to the costs of unserved energy as the system swings between excess water and drought conditions. Ensuring cost recovery in the Brazilian system therefore requires a different approach for setting dispatch rules.

Efficient competition in generation requires two markets

Reconciling central dispatch with the desire to introduce competition and achieve cost recovery requires focusing competition not on the physical dispatch of energy but on relevant fi-

nancial (contractual) arrangements. Thus, there should be two generation markets: a spot market and a contracts market. As in other power sector models, the spot market would be used to trade energy within a defined period (typically one hour) and would determine short-run marginal cost dispatch. Generators would recover their variable costs, excluding fuel costs, in this market. But unlike in thermal-based systems, generators would recover capital (and fuel) costs in the contracts market, and the price of the financial instruments traded in that market would be the price signal for investment.

The contracts market would work as follows. Generators would be issued firm energy certificates (FECs), which they would sell to distributors and large users. Each FEC would give the holder the right to obtain from the system a specified amount of energy. The certificates could be freely traded in the contracts market among generators, distributors, and large deregulated users, and distributors and large deregulated users would be required to hold FECs as a condition of access to the spot market. The basic idea is that, with the FECs, the generator sells its capacity to the system during a given period, rather than the energy produced during that period.² The requirement that distributors and large deregulated users buy firm (contracted) energy as a precondition for purchasing energy from the spot market creates a market for the FECs.³

The requirement for purchasers in the spot market to hold FECs in direct proportion to the amount they want to buy solves the problem of creating incentives for users to buy all energy requirements on the spot market when marginal costs are very low, thus paying only variable costs and not contributing to the recovery of generators' fixed costs. The risk that buyers without FECs will make spot market energy purchases can be handled in different ways. One possibility is to simply prohibit these purchases. But this solution would require the central dispatch entity to keep track of existing FECs to see whether demand will be covered. An alternative that would require less

monitoring is to impose a financial sanction on purchasers who withdraw energy from the system exceeding their holdings of FECs. If the sanctions are set at an appropriate level—for example, at the system's long-run marginal cost—and properly enforced, there will be no incentive for purchasers lacking the FECs they need to buy unauthorized energy on the spot market.⁴ The proceeds from the sanctions can be divided among all generators in proportion to their firm energy.

To ensure that FECs are used properly and effectively in the market, they should be fully tradable until they are "cashed in" for immediate delivery. Agents in the market need to be able to freely buy and sell the certificates to accommodate their needs at any given moment. As in any financial market, paper transactions in the energy market are expected to exceed actual physical transactions by several times.

Implementation

This market structure implies that the contracts market should be completely independent of physical dispatch. But it may be difficult to persuade the current dispatch managers of the need to delink the two. One possible enticement to persuade generators to transfer control over production decisions to the central dispatch entity is to provide them with entitlements to energy proportional to their contribution to the system. Because the central dispatch entity, seeking to optimize system operation, is bound to increase the amount of energy obtained from plants, each generator would receive entitlements at least equivalent to its own (isolated) physical contribution. These entitlements (FECs) could then be freely sold to purchasers in the contracts market. There should be no constraints on trading in these energy contracts by generators, distributors, large deregulated consumers, and brokers (if any). Trading could be organized in a physical market (similar to a stock exchange) or on an over-the-counter basis, or it could be done through bilateral transactions, which would probably lead to the spontaneous emergence of some kind of centralized market.



Summing up

In the system described in this Note, costs could be recovered by requiring distributors to purchase sufficient amounts of firm energy to cover their expected demand as a precondition for buying energy on the spot market. This obligation would eliminate any free-riding by purchasers who would otherwise gamble on buying secondary energy in the spot market. The value of firm energy would be freely negotiated in this market and would signal any need for new generation capacity.

Distribution companies would be responsible for buying firm energy (in the form of FECs) to cover the forecast demand of their captive consumers. Once this obligation is met through the contracts market, the distributors could buy energy on the spot market. The cost of both contract and spot market purchases would then be bundled with the cost of distribution to set tariffs for retail sales to captive users.

Large users (those above a defined size threshold) could bypass the distributors to purchase their requirements directly on the contracts and spot markets. They would have to pay regulated tariffs for the related distribution service (use of wires) provided by the distribution company to which they are connected. Large users could also buy FECs in the contracts market and resell them to other large users or to distribution companies. But they could not provide distribution services, which is the exclusive right of distribution companies.

For this mechanism to be effective, an obligation would have to be imposed on distribution companies to serve all captive users in their concession areas. Setting the penalty for not meeting demand as a function of the value of lost load would send the proper signal on how much should be invested in new generation plants. As long as the cost of FECs is lower than the value of lost load, it is efficient to build a new plant. Because distribution companies act as representatives of their captive users, the value of lost load, which represents

the maximum price users are willing to pay for the service (the reserve price), would have to be determined by the regulator through periodic reviews. New investment would occur up to the point at which the cost of new plants exceeds the reserve price.

The model proposed by this Note is not the only solution to the technical challenges of introducing effective competition in Brazil's power generation sector. Alternative solutions may well emerge from ongoing work. But the Note does outline one approach to developing an internally consistent set of reforms that recognizes the special characteristics of hydro-based electricity systems such as Brazil's and takes advantage of the benefits of incentive-based organization and regulation.

For more information, see Martin Rodriguez-Pardina and Antonio Estache, "Exploring Market Options for the Reform of Brazil's Electricity Sector" (Economic Note 12, World Bank, Latin America and the Caribbean, Country Department I, Washington, D.C., August 1996).

- ¹ Some estimates put the losses associated with decentralized dispatch in Brazil as high as 18 to 20 percent of annual energy generation, representing a cost of US\$1.2 billion a year.
- ² Certificates are based on firm energy rather than capacity because hydro systems are energy- rather than capacity-constrained. The firm energy of a system is defined as the maximum amount of energy that it can produce without exceeding the predetermined loss-of-load probability (which in Brazil is 5 percent). For each generating plant, the firm energy is the contribution by that plant to the system's firm energy. To calculate the contribution of a plant requires running a simulation model for the entire system with and without that generator. The difference between the two results is the firm energy of the plant. This approach captures all externalities associated with the plant as part of its firm energy.
- ³ This kind of arrangement partially mimics the capacity-contract-based pool operating in New England.
- ⁴ If ex post trading of FECs is authorized (and it should be), any agent would be able to cover its position unless the system is short of firm energy—in which case, the market price sends a signal to cut consumption in the presence of excess demand.

Antonio Estache, Economic Development Institute (aestache@worldbank.org), and Martin Rodriguez-Pardina, Private Consultant

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