
PRIVATIZING THE ELECTRIC POWER SECTOR IN BRAZIL

Carlos Kawall Leal Ferreira*

“Brazil is *sui generis*; perhaps it is time to review the received Latin power privatization wisdom in the Brazilian setting” [Feldman (1997, p. 13)].

Executive Summary

The ongoing privatization of Brazil's electric power industry and the implementation of a new model for this sector is part of Brazil's economic transition from state-led to market-led growth. It is also consistent with the utility sector's need to raise productivity and reduce costs through increased efficiency, a goal which the entire economy must achieve in order to successfully integrate into the global marketplace. Privatizing the electric power sector also helps to reduce public sector debt, thereby contributing to the fiscal adjustment Brazil must make in order to sustain long-term growth.

From a macroeconomic standpoint, these goals might not differ from those of other Latin American or European countries that have pursued privatization. However, certain features unique to its power sector prevented Brazil from simply replicating utility-sector models and examples that have previously worked elsewhere.

- First, the *technical characteristics* of Brazil's electric system were fundamentally driven by the country's vast river network. The power sector's consequent emphasis on hydroelectric power generation led to the creation of a centralized dispatch model and an interconnected transmission system.
- Second, the *structure of ownership* in Brazil's power sector was relatively complicated. Although the utility industry as a whole was publicly owned, the Federal Government owned the generation and transmission assets while the state governments owned the distribu-

* Professor of Economics at the Catholic University of São Paulo, received his Ph.D in Economics from the University of Campinas. In 1995 and 1996, was responsible for investor relations at Cesp and Eletropaulo, and also participated in shaping the privatization process for the electric power sector in São Paulo state. The author wishes to thank the enlightening comments and suggestions made by Antonio Parkinson de Castro on a draft version of this article. Rich Gasparre provided the invaluable support on English editing while Adriana Dupita edited graphs and tables. None of them is responsible for any of the text's weaknesses or mistakes, which should be fully attributed to the author.

tion companies, as well as some vertically integrated utilities. Moreover, many of the state-owned utilities suffered from being *excessively leveraged*. Both the ownership and debt situations militated against implementing privatization as a one-shot, all-inclusive deal.

- Third, *large investments in new generation assets* are now needed because the increase in electric energy demand, especially from households, has not been met with adequate investments in electrical generation over the last ten years as a result of a lack of financing.

When President Cardoso decided to privatize the power sector at the beginning of his first term in 1995, the critics of this decision argued that these unique characteristics would not permit privatization to succeed because the centralized core of the electric system could not be dismantled or decentralized. If that argument were true, selling the sector as a monopoly to private owners would have led to typical private sector monopolistic costs without generating any economic benefits from competition, and thus would have been counterproductive.

On the other extreme, privatization enthusiasts supported a fast-track process, which they claimed was needed to increase investment immediately (particularly in new generation capacity) and improve management. In their view, the benefits of transferring ownership quickly, and thus improving the sector's financial and operational conditions, outweighed the risk of not introducing the proper regulatory framework before privatization. Not surprisingly, proposals aimed at "unbundling", or deverticalizing, the power sector and creating a new competitive model for power generation and distribution were criticized as "academic" by the fast-trackers, who blamed them for slowing down the privatization process.

Fortunately, both privatization critics and hard-liners are currently being proven wrong. First, roughly three years after the privatization of power assets began, more than 50 per cent of the distribution of electric power is under private ownership and the major power dams are just beginning to be sold off. In three years, the Federal and state governments have already received US\$ 20.8 billion from utility privatization.

While these numbers suggest that privatization skeptics placed their bets on a losing cause, it is also true that privatization and the implementation of a new model for the electric power sector have proceeded hand in hand, contrary to the expectation of privatization enthusiasts. A new regulatory system has been created and a wholesale electricity market will be gradually introduced; significantly, prices paid in the privatization auctions have increased as the rules and regulation related to the newly privatized environment have been clarified. Furthermore, new

power projects are already starting to pick up, aided by a secular shift to a macroeconomic environment of low inflation.

Of course, challenges and dilemmas still exist, and are likely to continue for some time. The new regulatory agencies at the federal and state levels have just been created and have yet to build a reliable track record in assuring both quality service for customers and attractive returns for investors. The generating system must be expanded in order to meet the challenge imposed by the increase in the marginal cost of supplying electric power from the hydropower generation segment. An optimal solution here would require balancing the cheaper energy that comes from the older hydropower plants with the energy coming from new gas-fired thermal plants. Finally, the “stranded costs”, or sunk investment capital, left over from unfinished hydropower plants have rendered them unable to compete in a totally competitive market.

Nevertheless, the careful yet steady pace of the process is reassuring. So far, the measured rate of privatization has enabled Brazil to avoid major false steps or dead-end roads, maximize the revenues generated by utility sales, and facilitate the development of project-based financing for power generators.

The text is divided into ten topics. We begin with the birth of the centralized model for the electric power sector in Brazil in the 1960s, examining in particular the creation of Eletrobrás. Our intent is to show that the centralized model was justified then both on technical grounds – the country’s geographical extension and the emphasis on hydropower generation – and on political and economic factors related to the solid state-led growth that the country experienced from the 1950s to the 1970s.

The exhaustion of the centralized model in the 1980’s is the subject of the second topic. Exhaustion reflected the distortions inherent in this kind of model, mainly the lack of stimulus to improve microeconomic efficiency. However, it also reflected the crisis in public sector financing after the external debt crisis that followed the Mexican default in 1982; this financing crunch left several utilities with high and unsustainable debt levels.

The following topics are related to the implementation of the new model. We start by describing the important features of the new laws implemented in the first half of the present decade that started to break down the centralized “status quo” model. Also crucial were the new laws governing concession bidding, which started the process of unbundling the electric power sector into its constituent activities of distribution, transmission and generation. We then analyze the main recommendations of the watershed study by Coopers & Lybrand (hired by Eletrobrás): the study’s objective was to establish a competitive electric power market in Brazil. The fifth topic concerns the law enacted in May

1998 that implements the Coopers & Lybrand suggestions, in particular the Wholesale Electricity Market and the National Operator for the Electric System (responsible for the operation of the transmission and dispatch systems). In the sixth topic we discuss the creation of the new regulatory agency (Aneel) and the process of setting tariffs for the privatized distribution utilities (using the price cap concept).

The following topics concern the privatization process. The seventh topic addresses the privatization models at the state government level, focusing on the cases of São Paulo and Rio Grande do Sul, which involved splitting up vertically integrated utilities. We then proceed to discuss the results to date of the privatization process, both at the federal and state levels, showing how auction revenues rose once the regulatory structure was developed and clarified. However, privatization revenues in 1998 were somewhat impacted by the financial restrictions related to the emerging markets crisis, which increased the costs of acquisition finance.

The prospects for investment in the electric sector are discussed in the ninth topic, where special emphasis is given to new investments in electric generation through gas-fired thermal plants. The concluding remarks constitute the final topic.

1. The Historical Legacy: The Centralized Model and the Creation of Eletrobrás

The development of the electric power sector in Brazil was influenced by the country's continental dimensions and the huge hydropower potential of its river basins. The significant economies of scale resulting from the construction of large power plants led to the creation of an interconnected power transmission system in which the utilities shared the costs related to the transmission lines. The large capital outlays involved in this process meant that co-operation rather than competition was the best option for the electric utility companies. The first step in implementing the centralized model was the creation of regional monopolies for distribution [Oliveira (1997, p. 48)].

The establishment of monopolistic distributors was followed by the development of a "centralized dispatch system", which maximized the efficiency of the hydropower generation facilities as a whole. Since several hydropower plants (often owned by different companies) can operate in the same river basin, the water flow coming from one dam is the "fuel" for the other plants downstream. By determining when each power plant will generate energy and how much energy it will generate, the centralized

dispatch system assures that the available water is used in the most efficient manner, thus optimizing total energy output at the lowest cost. If one company ends up generating less energy than its contracts require, it will obtain energy from another utility that has generated power in excess of its needs, paying the operating cost of the energy acquired. Eletrobrás estimated in 1996 that, by optimizing the water flows usage, the centralized dispatch system generated total efficiency savings of US\$ 3.7 billion, equivalent to 2,200 MW of capacity [Santos (1996)].

The centralized system not only was regarded as the most efficient model on technical and economic grounds, but also fit into the state-led growth model that prevailed in Brazil after the Second World War, when the country made the transition from an agricultural export economy to a newly industrializing economy. Following the import-substitution model, the public sector was responsible for investments in capital-intensive but low-return infrastructure, which typically were the “natural monopolies”. Such investments would create demand for private contractors and capital goods industries. Following the import-substitution model, Brazil also developed a system of tariff subsidies to make energy cheaper for industry, with the residual costs borne by consumer households and non-industrial businesses.

The centralized system was implemented directly after the creation in 1963 of Eletrobrás, the federal holding company that owned the majority of the country’s transmission and generation assets through its four subsidiaries (Chesf, Eletronorte, Eletrosul, and Furnas). It also controls Brazil’s nuclear power assets (one plant is currently in operation) and has a 50 per cent stake in Itaipú Binacional (jointly owned with Paraguay), currently the largest power generation plant in the world with 12,000 MW of capacity.

In addition to its mandate to expand power supply and make the appropriate transmission investments, Eletrobrás also became the sponsor and coordinator of two industry-wide organizations. In 1973, the Coordinating Group for the Interconnected Operation (GCOI) was created to control the centralized dispatch system through water flow optimization as described above. In 1982, the Coordinating Group for the Planning of the Electric System (GCPS) was created to project energy demand through macroeconomic forecasting and, based on the forecast results, to define the investments needed for the expansion of generation, transmission and distribution activities. It also established the schedule of investment projects, and prioritized the most efficient ones.

Eletrobrás was also responsible for the administration of the significant financial resources it was given for power sector investments (many of which were targeted to the northern and northeastern regions). Its financial resources included the RGR,

an assessment charged to power companies in proportion to their assets, and revenues derived directly from end users. These revenues included not only specific taxes on power usage, but also compulsory loans that big power consumers were compelled to make to Eletrobrás for expansion of infrastructure.

Investment funds so derived in turn were reloaned by Eletrobrás to various operating utilities based on its ten-year investment plan, which is annually updated by the GCPS. However, the power companies also began to tap the capital markets for increasing amounts of debt, drawing especially from the syndicated loan market that flourished in the 1970s. Such loans were collateralized by a sovereign guarantee.

While the centralized model appeared to work reasonably well, it was not all-encompassing. The model theoretically left to state governments the responsibility only for power distribution through monopolistic utilities operating at the state level. However, the richer state governments in the southern and southeastern regions resisted this centralized model and actually implemented aggressive investment programs to create their own generation and transmission assets for accommodating better their larger industrial base and more rapidly growing economies. Over the long term, these programs made state-owned generation and transmission assets an important part of Brazil's utility sector. As Table 1 shows, Cesp, Cemig, Copel, and CEEE had a considerable share of Brazil's power generation assets by 1995, aside from their control of distribution activities.¹

Regarding the transmission system, two major interconnected systems were ultimately created, one for the North/Northeast region and another for the South/Southeast region.² In the north of the country (mostly in the Amazon region), some isolated systems were developed to serve the urban areas along the rain forest.

Because of the historical trends that favored hydropower development, thermal plants have a minor stake in Brazil's electric power generation (as shown in Table 1), except for the isolated systems in the northern regions. The thermal plants that operate in the interconnected system do so on a stand-by basis because of their higher costs. They are usually turned on during exceptionally dry seasons, and generally operate at peak load to optimize both their own and hydropower generation. The higher costs of the thermal plants are shared by all companies in the interconnected system through the "fuel consumption account" (CCC), which effectively subsidizes the additional costs that thermal plants incur relative to hydropower plants.

1 Light and Eletropaulo also had significant generation assets, but they were mainly distribution companies.

2 Eletrobrás is actually investing in a transmission line that will connect both systems.

Table 1
Installed Power Plant Capacity - 1995
(In MW)

<i>Companies</i>	<i>Hydroelectric Plants</i>	<i>Thermal Plants</i>	<i>Total</i>
Eletronorte	4,718	783	5,501
Chesf	8,617	290	8,907
Furnas	7,212	1,297	8,509
Eletrosul	2,602	620	3,222
Eletrobrás (Total)	23,149	2,990	26,139
Itaipu	6,300		6,300
Cesp (SP)	9,461		9,461
Cemig (MG)	4,928	125	5,053
Copel (PR)	3,324	20	3,344
CEEE (RS)	896	511	1,407
Light (Private)	768		768
Celg	675	3	678
Eletropaulo	820	470	1,290
Total	27,172	1,129	28,301
Other	514	558	1,072
Overall Total	50,835	4,677	55,512

Source: Oliveira (1997, p. 12).

Also significant is the contribution of Itaipú, the power plant jointly owned with the Government of Paraguay. Under a law enacted in 1973, power distribution companies were obliged to buy a pre-defined portion of Itaipu's generating capacity in proportion to their market share. The cost of the energy acquired from Itaipu is based on the debt service from the plant, plus a transmission fee.

The centralized system also included a regulatory agency, the National Department for Water and Electric Power (DNAEE), created in 1965. This agency, which was formally under the jurisdiction of the Ministry of Mines and Energy, was responsible for granting concessions for generation, transmission and distribution activities. However, under the old model, there was no need to solicit competitive bids when granting concessions.

DNAEE, however, had no independence, and, as a matter of fact, did not even have the leading role in setting tariffs for the sector. Since most of its employees came from the utilities themselves, there arose the typical problem of the regulator being captured by the regulated [Pires and Piccinini (1998, p. 35)]. DNAEE's involvement in tariff management was further reduced after 1975, when the Ministry of Finance began to handle tariff readjustments as part of its effort to control increasing inflation.

In 1974, power tariffs were equalized throughout the country. Given annualized inflation of 30-40 per cent a year in the mid-1970s, tariff readjustments were crucial to preserve real returns for all the power companies. In response, a principle to assure to the utilities a minimum return of 10 per cent on their

assets was adopted. Since tariffs were equal while the structure of costs and assets differed, there was a need to compensate companies with lower returns by extracting incremental revenues from those with higher returns. The mechanism to do so was the Returns Compensation Account (CRC), in which companies accumulated positive or negative results for latter settlement. The CRC was designed as a zero-sum mechanism for the utility sector as a whole, although high inflation later created effective net losses for the sector as a whole.

By centralizing planning, operation, and, to some extent, even the financial resources for investment, the Brazilian electric power sector grew quickly in the late 1960s and 1970s, mirroring the growth of Brazil's economy as a whole, while continuing to subsidize industrial consumers. This growth was aided by the suppression of non-economic issues; in particular, legislation regarding land usage and environmental issues (huge portions of land had to be flooded to create the dams for the hydropower plants) was almost nonexistent during this period, due to the priorities of the military government then in power.

Nevertheless, the centralized system accomplished its strategic objectives. By 1995, Brazil had built 55,512 MW of power generation capacity, 153,406 km of transmission lines (including those of 34 KV or more) and 1.6 million km of distribution lines [Oliveira (1997, p. 11)]. Even though the centralized system ultimately broke down under its own financial weight, it should be judged an historical success.

2. The Crisis of the Centralized Model in the 1980s and the Need for Restructuring

Entering the 1980s, the centralized model had begun to show signs of economic and financial weakness. Fundamentally, the centralization of planning and the availability of easy financing insulated investment decisions from the kind of scrutiny used to evaluate private investments – that is, discounted cash flow analysis.³

In the centralized environment, engineering personnel commonly ruled the power companies, leaving financial officers with the task of “paying the bills” and arranging for the needed financing. While coherent with the state-led strategy in place in the 1970s, this culture supposed no restrictions on financing. Because economy of scale was the priority that drove most

3 For instance, none of the 20 power plants built in the State of São Paulo by Cesp were evaluated using a cash flow analysis.

investment decisions, larger plants were usually preferred to smaller ones. This led to huge projects that required large capital investments and long lead times – factors that later prevented many of them from being completed [Oliveira (1997, p. 27)]. By 1992, such paralyzed investments in power plants had reached US\$ 10 billion, and the idle assets represented 10 GW of potential additional capacity [Pires and Piccinini (1998, p. 35)].

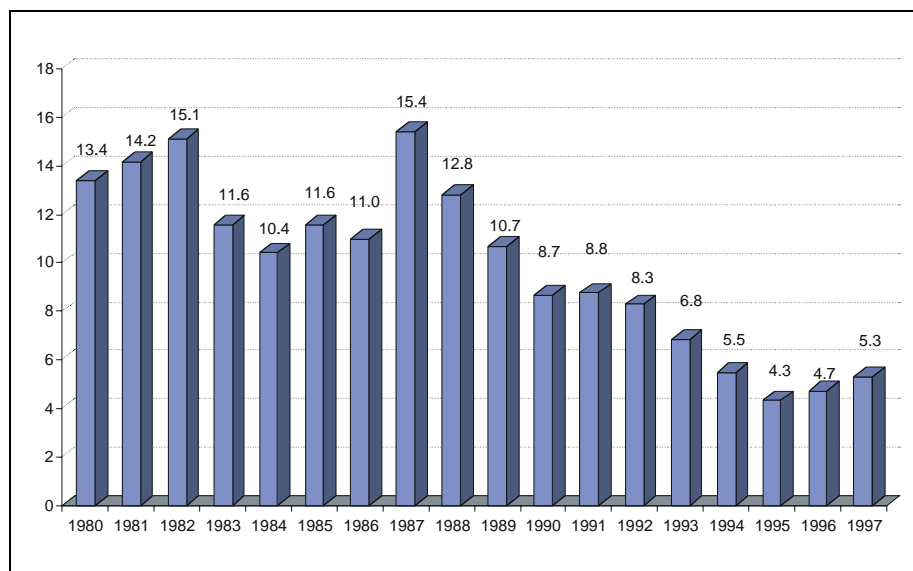
Moreover, since a comfortable return on assets was guaranteed, there was no incentive for increasing efficiency. In a problem shared by state-owned companies in other sectors, the power utilities lacked control of operating costs, largely because they had no motivation to understand (and hence no understanding of) operating cash flows at even the most basic levels. Such ignorance was especially baneful considering the different nature of investments, maintenance costs, and returns involved in the dissimilar activities of power generation, transmission, and distribution. Costs only mattered on the accounting basis, as they were the baseline for setting tariffs to achieve the minimum guaranteed reward.

In 1982, the collapse of international financing following Mexico's external debt default produced in Brazil a triple whammy of a severe fiscal crisis, economic stagnation, and very high inflation. To alleviate the burden of the economic crisis on consumers, public sector tariffs were often used as an anti-inflation tool by policy makers, who kept rate readjustments well below inflation levels. Utilities responded first by cutting back their investment programs as demand fell and borrowing costs jumped. However, this action proved insufficient given the necessity of investment for maintenance and at least some expansion; indeed, some utilities' revenues were not even adequate to cover operating costs. Therefore, most utilities had no choice but to expand borrowing activities and increase their leverage.

At the same time, by not achieving their minimum 10 per cent return on assets, the power utilities as a group started to accumulate a growing net creditor position on their CRC accounts (i.e., the system was no longer zero-sum). Since the government was not allowing adequate tariff adjustment, the utilities looked to the government for compensation via the CRC mechanism, which, given its own problems, the government refused to provide.

On the financing side, the public sector crisis deprived the centralized model of the low-cost financing which it had come to take for granted. No longer could utilities base their financing on a sovereign guarantee, regardless of their own microeconomic efficiency. As a result, financing costs shot up at the same time that borrowing became a more important (and in some cases critical) source of capital. Graph 1 shows how this phenomenon impacted investment levels in the power sector. From a range of US\$ 14 billion/year from 1980-82, investment fell to an average

Graph 1
Historical Electric Power Sector Investment - 1980-97
(In Billions of US\$)



of US\$ 12 billion for the rest of the decade. In the 1990's, investment collapsed, reaching levels of less than US\$ 5 billion in 1995-96.

Table 2 shows how this financial crisis affected the revenues and expenditures of the power companies. On the revenue side, loans and external financing increased as a proportion of total revenue when tariffs decreased in real terms. On the expenditure side, investments fell significantly as rising debt service crowded them out. Consequently, the power sector had negative net working capital from the second half of the 1980s onward.

Table 2
Aggregate Financial Sources and Uses in Brazil's Electric Power Sector - 1970-94
(In %)

	1970	1975	1980	1985	1989	1994
Sources of Funding	100	100	100	100	100	100
Internally Generated Resources	42	44	44	38	11	67
Operating Revenue	25	20	29	25	8	54
IUEE	7	8	4	3	0	0
Compulsory Loans	10	7	5	4	2	0
RGR	0	9	6	6	1	13
Federal and State Governments*	21	18	5	2	44	21
Loans and Market Financing	37	38	51	60	45	12
Uses of Funding	100	100	100	100	100	100
Investments	76	75	54	40	25	70
Interest Payments on Debt	14	15	31	68	98	66
Dividends and Other	0	2	7	2	19	8
Change in Net Working Capital	10	8	8	-10	-42	-44

*Including CRC appropriation; the ballooning of this category in 1989 represents the lack of government compensation discussed in the text.

Source: Oliveira (1997, p. 130).

Exacerbating the financial crisis was the rising importance of environmental issues in the 1980s. After the returned to democracy in Brazil in 1985, legislation was enacted which obliged the developer of any large investment, such as a power project, to conduct an Environmental Impact Study/Report, the so-called EIA/RIMA. This new procedure in most cases led to significant compensation payments to municipalities and communities whose properties were flooded by the reservoirs associated with new hydropower plants (fortunately for the utilities, such compensation was not made retroactive). These payments, which naturally raised the cost of these projects, became more frequent and costly as local governments regained power through restoration of democracy.

Still, managerial efficiency seems to explain why the financial crisis affected some companies more than others. At the end of 1995, total debt in the power sector reached US\$ 25 billion, or 14.43 per cent of total assets. This ratio differed significantly among companies, as can be seen in Table 3. In some companies, total debt exceeded 25 per cent of total assets. In particular, just one company (Cesp) accounted for over 25 per cent of total debt, while (as Table 3 indicates) similar companies like Cemig and Copel, which were also vertically integrated utilities like Cesp, had much lower debt/asset ratios of 6.56 per cent and 10.47 per cent, respectively.

The crisis was worse in the utilities owned by the state governments. When state-owned banks ran into problems in the early 1980s, some governments started to use their power companies to finance their public deficits indirectly. This could be done by making these companies responsible for some activities not related to their core business.

Several variations of this scheme occurred in the State of São Paulo, for example. Cesp, which owns almost all generation assets in the state, made significant investments in the Tietê-Paraná waterway (actually subsidizing the private sector interests in the region) without receiving any compensation from the funds allocated to the project in the state's budget. Eletropaulo, the country's biggest distribution company at that time, was responsible for flood control operations in the main rivers in São Paulo city, but was not rewarded by the state government, its primary shareholder.

In some cases, power companies were used as a front to hire highly paid workers who would not actually work there, or who would be lent to other government entities with no compensation. It was also common practice for public entities not to pay their power bills – a practice that also involved some local governments with political ties to the state governor.

Table 3
Debt-to-Asset Ratios in the Electric Power Sector
(In Millions of US\$)

<i>Company</i>	<i>Debt</i>	<i>Assets</i>	<i>Debt/Asset Ratio (%)</i>
Furnas	1,433,770	27,744,757	5.17
Eletrosul	1,114,887	7,650,299	14.57
Chesf	4,712,543	21,441,668	21.98
Eletronorte	1,584,606	21,724,591	7.29
Light	585,904	8,162,073	7.18
Ceal	115,248	337,401	34.16
Ceam	7,013	328,403	2.14
CEB	25,416	551,580	4.61
CEEE	1,516,150	5,710,198	26.55
Celesc	74,844	1,748,243	4.28
Celg	753,468	2,572,262	29.29
Celpa	129,432	955,995	13.54
Celpe	30,187	863,437	3.50
Cemar	83,285	713,028	11.68
Cemat	106,638	950,707	11.22
Cemig	777,763	11,860,565	6.56
Cepisa	24,741	263,707	9.38
CER	5,425	32,097	16.90
Cerj	195,695	622,686	31.43
Ceron	63,719	313,600	20.32
Cesp	6,409,024	24,277,892	26.40
Coelba	352,002	1,875,663	18.77
Coelce	110,244	676,351	16.30
Copel	619,268	5,912,560	10.47
Cosern	59,772	348,150	17.17
CPFL	243,637	3,192,332	7.63
Eletoacre	12,385	92,991	13.32
Eletropaulo	1,777,539	12,870,639	13.81
Energipe	19,591	163,884	11.95
Enersul	265,094	962,492	27.54
Escelsa	1,543	926,102	0.17
Saelpa	14,490	246,683	5.87
Total	23,225,325	166,093,034	13.98

Source: Oliveira (1997, p. 38).

3. Shaping a New Model in the 1990s: The New Tariff and Concession Laws

As Brazil moved into the 1990s, the centralized model was still afloat, but its many leaks – its economic inefficiency, vulnerability to financial distress, and crippling debt servicing – indicated that it was no longer the best way to achieve progress. Consequently, a new model was highly desirable, if not absolutely necessary.

3.1. The End of Tariff Equalization and the Minimum Return on Assets

The first move towards reform was adopted in 1993, with the approval of Law 8,631. This law eliminated the geographic equalization of tariffs and the 10 per cent minimum return on assets. The new formula for establishing tariffs was based on the cost structure of the utilities, and was designed to reflect the companies' cash flow needs rather than an arbitrary target for return on assets.

Also important was the subsequent elimination of the approximately US\$ 25 billion in CRC credits held by the utilities. These unpaid credits were partially used to offset the roughly US\$ 5 billion in arrears owed by the utilities on their energy purchases from Eletrobrás. In other words, Eletrobrás absorbed the implicit subsidy that had been extended to consumers in the earlier years through the reduction of the real value of consumer tariffs, which had caused the CRC credits to accumulate in the first place. The remaining US\$ 20 billion in credits were used to pay federal taxes [Pires and Piccinini (1998, p. 38)]. Also, utilities with excess credits were allowed to sell them to other utilities or to apply them against future debts they might have to the government.

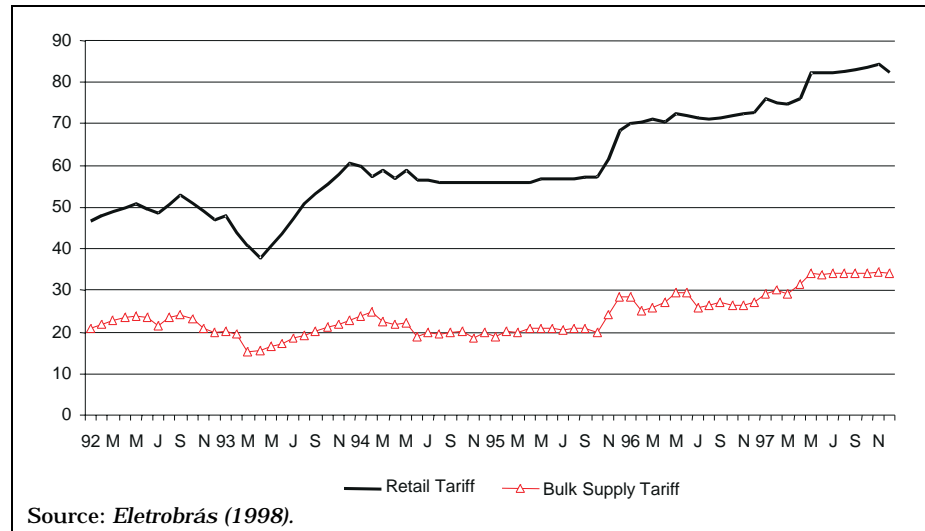
In the wake of Law 8,631, two sets of electric power tariffs were defined. The *bulk supply* tariff is the wholesale rate charged by a power generator in selling to distribution companies; this rate also includes the costs of using the high-voltage transmission lines. (In the new model, generation and transmission charges will be separated.) The retail tariff is the rate charged by distribution companies to end users; this rate differs by sector (e.g. households, industries, commercial companies) and by the amount of energy consumed.⁴

Graph 2, however, shows that Law 8,631 was not initially effective in helping electric power tariffs to recover in real terms. Immediately after the law was enacted, President Itamar Franco decided that public tariff adjustments had to lag inflation in order to benefit the population. By that time, the privatization program in Brazil had already technically commenced, but there was limited commitment from the president to push it forward aggressively.

Nevertheless, as Graph 2 illustrates, real values of energy tariffs began to recover in late 1993, and continued to regain ground in the following years. The initial stimulus for this recovery came from the utilities, which lobbied against President Franco's inflation-lagged tariff policy from its inception and over

4 In Pires and Piccinini (1998) there is a detailed discussion of tariff-setting procedures in the Brazilian electric power sector.

Graph 2
Average Prices for Electric Energy - 1992-97
(Current Prices, R\$/MWh, without Itaipu)



time won modifications. More important, however, was the adoption of the Real Plan in July 1994, and the subsequent collapse in inflation.

3.2. The New Concession Laws

Serious restructuring and privatization of the electric power sector was kick-started into high gear only after President Cardoso took office in 1995. In early 1995, Congress approved the General Concession Law (officially, Law 8,987). Conceptually, this law was designed to be a practical and effective expression of the 1988 Constitution, which required concessions to be granted through competitive bidding. Therefore, the General Concession Law provided the general rules for concession bidding in a number of infrastructure segments, including electric power. Rights and obligations of the concessionaires were established, and the need for a tariff system and regulator that would guarantee the “economic and financial balance” of the concession was recognized.

Building on the groundwork laid by Law 8,987, Law 9,074 was approved in mid-1995. This legislation established a number of principles related to the renewal of power sector concessions. Old concessions could be renewed or new ones granted after generation, transmission, and distribution activities were unbundled. Tariffs for new or renewed concessions were to be based on the structure of costs of each segment of the electricity market (generation, transmission and distribution). The original bulk supply tariff was to be broken down into separate, visible costs for power generation and transmission, which were added together to arrive back at the bulk supply tariff.

Regarding power generation concessions, Law 9,074 extended by 20 years the concessions of power plants that were under construction. In cases where the projects were formally deemed “delayed”, the company was obliged to present a plan for completion in which private equity accounted for at least one-third of total financing, in order to encourage the application of project finance techniques. Several attempts were made to introduce private capital to complete unfinished power plants (some of them had even been made prior to the enactment of Law 9,074), such as the power plants of Serra da Mesa, Itá, Jacuí, and Canoas.

Law 9,074 was also important because it introduced the concept of the independent power producer (IPP). Previously, private power generators could only produce energy for their own consumption or to sell to the distribution concessionaires. Law 9,074 established that an IPP could sell its energy to “free consumers”, defined as those who had an energy load equal to or above 10 MW and used voltages of 69 KV or over.

4. The New Model Proposed by the Coopers & Lybrand Study

At the beginning of 1995, the government of São Paulo State proposed a pioneering model for restructuring that envisioned unbundling the three companies it owned (Cesp, Eletropaulo and CPFL) in order to privatize them. This proposal was met with fierce criticism both by those who opposed unbundling and privatizing the companies on principle and by those who, despite their approval of privatization in general, wanted a faster process, even at the cost of not implementing a competitive environment in the power sector.

In spite of its breakthrough features, the São Paulo model could not move forward if certain factors that would impact the model at the federal level were not defined. These factors included questions related to the centralized dispatch system, the treatment of the transmission lines, the need for splitting up generation and transmission tariffs and other related issues. Moreover, investors were unlikely to commit capital to new utility projects unless the new regulatory environment, and especially the process of setting tariffs, was clearly established in advance.

In early 1996, Eletrobrás hired the American accounting and consulting firm Coopers & Lybrand through a competitive bid to devise a new model for the electric power sector in Brazil. As we will later note, this did not prevent the federal and some state governments from beginning to privatize distribution companies

on their own. However, a new model was crucial to privatizing power generation assets, as well as to creating the proper environment for stimulating privately owned “green field” generation projects. The challenge for Coopers was to create a workable decentralized model that would be effective even if some players in the sector did not privatize.

Coopers & Lybrand presented its report in mid-1997. Its main recommendations, analyzed below, were: (i) the creation of the wholesale electricity market (MAE); (ii) the establishment of “initial contracts” to provide a transition phase into the competitive power market; (iii) the unbundling of the transmission assets and the creation of an Independent System Operator (OIS) to manage the interconnected system; and (iv) the organization of planning and financial activities in this new setting.

4.1. The Wholesale Electricity Market (MAE), the Initial Contracts, and the Independent System Operator (OIS)

The creation of a new competitive environment through a wholesale electricity market in Brazil faced a number of challenges. The first issue was the need to consider the fate of the centralized dispatch system, which had been created to optimize in a technical sense the exploitation of exogenous hydrological resources. Eletrobrás’s experts had always opposed the dismantling of the centralized dispatch system on the grounds that it would end up increasing not only costs but also the risk of power shortages.

Another critical issue was that, unlike in other countries, the energy supplied by the existing power plants (the “old energy”) is actually cheaper than the energy that will come from the new projects (the “new energy”), either because the older hydropower plants represented the cost-efficient projects or because their capital costs had already been fully amortized.

Additionally, some companies have significant stranded costs from unfinished plants. These carry overs of sunk capital expenses would increase significantly the cost of energy from the generation companies (termed “gencos” by Coopers & Lybrand) which carried such costs. In other words, highly efficient companies would compete with others that would be inherently less competitive because they carried the additional burden of stranded costs.

The creation of the MAE, as proposed by Coopers & Lybrand, will replace the old regulatory command system in setting tariffs and the terms for the existing power contracts. The MAE will be the venue for setting a reference price for the energy sold through bilateral contracts among gencos and distribution

companies or related to an IPP and its free consumers. The MAE will also establish a spot price for energy that will reflect the short-term incremental cost of generating marginal energy; this spot price will be determined by agreement between the utilities and the regulator. The spot price will reflect only the generating costs, with the transmission costs paid separately by the distribution company.

Most of the energy consumed will continue to be negotiated through bilateral power contracts in order to reduce the price volatility experienced by all market participants. Also, power purchase agreements (PPA), or long-term contracts between IPPs and distribution companies/free consumers, will be needed to make project finance techniques feasible for green field generation projects. It is expected that the spot market will only reach 10 to 15 per cent of the MAE [Pires and Piccinini (1998, p. 44)]. Physical delivery specified by bilateral contracts will be assured by a new entity, the OIS, which will have a role similar to that filled by the GCOI in the centralized model.

The OIS is designed to retain the technical benefits of the centralized dispatch system while allowing asset ownership to be decentralized. The OIS will have under its control all flows of energy negotiated in both the bilateral and spot market, so as to optimize output from both hydropower and thermal generation assets. If an exceptionally dry season makes energy rationing necessary, the OIS will unilaterally define energy allocations for all market participants, superseding the terms of the bilateral contracts and making all companies share the burden in proportion to their contracts.

In order to solve the problem of structural cost variance due to stranded costs and the differences between “new energy” and “old energy”, the Coopers & Lybrand study presented the idea of “Initial Contracts”. These are mandatory contracts that have to be signed between the power generators and distribution companies as part of the introduction of the new model. The concept is to have more efficient facilities sign contracts with lower prices while less efficient ones (especially those with high stranded costs) charge higher prices. All energy buyers would then have to take the same mix of high-price and low-price contracts – a procedure which would keep the new average cost of energy acquisition similar to the cost seen prior to these contracts. Through this mechanism, low-cost suppliers would not have to ration demand by raising prices, and high-cost suppliers would not be immediately forced into the role of the ‘backup’ producer, with all the attendant economic consequences.

The proposal by Coopers & Lybrand suggested that such contracts would last for 15 years (20 years in the case of the power plants in the North and Northeast). After six years (eleven for plants in the North and Northeast), such contracts would begin

to be phased out, gradually freeing the companies to buy increasing amounts of energy in the free market, either through bilateral agreements or in the spot market. This should give high-cost producers time to get their costs down, and finish or write off stranded plants. As Feldman states:

“The model does not propose one big bang, but a series of controlled detonations, through which it will progressively introduce a competitive power market. While this leaves private capital with some uncertainties, it is more realistic than the free market system in Eastern Europe” [Feldman (1998, p. 45)].

The energy acquired through the Initial Contracts will include also the power generated from Itaipú, nuclear power plants, and existing thermal plants that receive CCC subsidies. So as not to give cost advantages to vertically integrated companies (especially Copel and Cemig, which are not scheduled to be privatized), no more than 50 per cent of a company's energy needs could be auto-supplied. The remainder of its own generation would have to be sold through bilateral contracts or the spot market at the MAE.

4.2. Management of the Transmission System

The Coopers & Lybrand study recommended that the OIS be structured as an independent, not-for-profit agency acting neutrally under the supervision of the regulator (the Aneel, to be discussed in this article). Ownership of the OIS would comprise five groups of shareholders: the gencos, the transmission companies, the distribution companies, free consumers, and the public sector.

The OIS would be responsible for managing the transmission system (also known as the “basic net”), which has been defined to include transmission lines of 230 KV or above. OIS authority over this task is necessary because the ownership of the transmission assets will be shared by the federal and state governments, at least at the initial stages of the new model. While transmission companies could eventually be privatized, this step is not a priority because most assets of the power sector are generation and distribution, and because the national continuity of the transmission system does not lend itself to competition as do generation or distribution.

However, transmission charges would be unified under the administration of the OIS, since the transmission companies (termed “transcos” by Coopers & Lybrand) would, after being unbundled, establish a contract with the OIS under which the OIS will manage its day-to-day operations in return for recurring payments.

The transcos will continue to be responsible for maintenance of their assets and can be asked by the OIS to invest in the

expansion of the system, which would imply additional payments from the OIS to the transcos. Alternatively, the OIS can solicit competitive bids for a new transmission line concession. Under this arrangement, the gencos and distribution utilities would place contracts with both the OIS and the transcos. The transmission tariff would reflect the incremental cost of usage of the grid in different locations, based on the methodology of long-term marginal cost, so as to assure the viability of new investments.

4.3. Planning and Financing in the New Model

Despite its general advocacy of competitive solutions to structural questions, the Coopers & Lybrand model recommends that the centralized strategic planning currently carried out by the GCPS should continue as “indicative planning”. However, the planning would be conducted by a new entity, the Institute for the Development of the Electric Power Sector, with a structure of ownership similar to that of the OIS. The indicative planning would have a 25-year time frame, and would involve studying hydrological capabilities, environmental impacts, and related issues. The objective of the research would be to find the best destinations for private investments in the utility sector without creating predetermined, binding priorities for private investment.

A more controversial proposal from the Coopers & Lybrand report suggests keeping Eletrobrás as the Financial Agent (AFS) for the electric power sector. Its resources would include the returns that Eletrobrás will receive from its outstanding loans to power companies, including Itaipu. The AFS could also on-lend money from entities like the World Bank and the Inter-American Development Bank, which conduct business only with government-owned institutions. The AFS could contribute to project financings by making subordinated loans, taking risks related to environmental issues or regulatory change. In such a role, Eletrobrás would be acting like a pure corporate holding company.

Even though Eletrobrás has clearly demonstrated expertise in financing the power sector, credit risk issues are more likely to be better managed by a financial institution, which also has broader funding alternatives. Ferreira (1995) proposes that the task of supporting project finance through subordinated debt and other vehicles should be assigned to BNDES, the Brazilian government development bank. Eventually, the funds currently managed by Eletrobrás could form a specific fund targeted to finance power projects, under the administration of BNDES.

5. Implementing the Coopers & Lybrand Model

The final step in completing the framework for the privatization of Brazil's generation assets was taken with Law 9,648, enacted in May 1998, which incorporated the bulk of the recommendations made by the Coopers & Lybrand report.

This law formally creates the MAE, which will establish the reference price for energy purchased through bilateral contracts while administering the spot market. The coordination of the dispatch system will be assigned to an OIS-type entity called the National Operator of the Electric System. Over a period not to exceed nine months, this entity will absorb the activities currently performed by the GCOI.

Law 9,648 also provided for the Initial Contracts. All power companies were obliged to sign new PPAs valid for the years 1998 to 2005, with the amount of energy bought defined by the GCOI for 1998 and by the GCPS (through its planning guidelines) for the remaining years up to 2002. In the three years that follow, the amount of energy bought under this scheme will be reduced annually by 25 per cent of the amount bought in 2002. Therefore, the initial contracts will last only seven years, much less than the 15 years recommended in the Coopers & Lybrand report.

The thermal plants that were part of the interconnected system as of February 6, 1998 will have their higher costs shared by all participants of the interconnected system (through the CCC account) until 2002. The CCC will be gradually phased out during the three years starting with 2002. Thermal plants which entered the system after February 6, 1998 will not receive such compensation through the CCC. Also by 2002 the RGR (the contribution paid by electric companies to Eletrobrás) will be eliminated, and the cost reduction will be transferred to consumers through lower tariffs.

Finally, the law authorizes the restructuring of the three remaining subsidiaries of Eletrobrás. The privatization of its first genco, Gerasul, was successfully achieved by mid-September 1998, effectively starting the privatization of Eletrobrás. Gerasul is the genco that resulted from the unbundling of Eletrosul, which also resulted in the creation of one transco.

The bulk supply tariff for Gerasul was set at R\$ 28/MW. The transmission assets of Eletrosul, which are still owned by Eletrobrás, will be rewarded according to the principle of the "revenue cap". This criterion establishes a maximum nominal amount for the transco's annual revenues after factoring in efficiency considerations [Pires and Piccinini (1998, p. 45)].

Regarding the other subsidiaries of Eletrobrás, Furnas can be divided into as many as three companies (two gencos and one transco); a former decision had already spun off its nuclear generation assets. Eletronorte should be split into six companies (five gencos and one transco), while Chesf should be transformed into two gencos and one transco. The privatization of the gencos thus created should proceed in 1999 and 2000.

By August 1998, all participants in the MAE, including the gencos, distribution companies and free consumers, had ratified the constitution under which the MAE operates. At the same time, the Initial Contracts were signed, thus marking the beginning of the new competitive power market.

6. The Aneel and the New Regulatory Environment

The implementation of a competitive model in the power sector also required a change in the regulatory environment. In late 1996, Law 9,427 created the National Agency for Electric Energy (Aneel), which took the place of the DNAEE. Established as an autonomous agency, the Aneel has an independent Board of Directors whose five members serve four-year terms. The Aneel's main tasks are:

- to institute technical parameters that assure the quality of service to consumers;
- to solicit competitive bids for new generation, transmission, and distribution concessions;
- to insure that the MAE operates in a competitive fashion;
- to establish the criteria for transmission costs; and
- to determine and implement retail tariff revisions.

With regard to the establishment of technical parameters for the service quality and supervision, the Aneel can share its responsibilities with local regulators operating at the state level, if both parties sign a formal agreement. One of the first such agreements was reached with the State of São Paulo. From its inception, the state's privatization model envisioned the creation of an independent regulatory agency; the State Commission for Energy Services (CSPE) was consequently established by law in 1997. In April 1998, the CSPE signed a cooperation agreement with the Aneel.

The Aneel also shares responsibility with other government bodies. In relation to gas-fired thermal plants, it should work in

cooperation with the ANP, the National Agency for Oil, since this agency will be responsible for the concessions for exploring and transporting natural gas.

The Concession Contracts and the Introduction of the Price Cap

As important as were the creation of Aneel, the Coopers & Lybrand report, and the legislation enacted to implement it, the privatization of distribution companies had already begun before these factors came into play. In 1995 and early 1996, the Federal Government successfully privatized its two distribution companies (Escelsa and Light). At the end of 1996, the first distribution company owned by a state government was privatized (Cerj, in the State of Rio de Janeiro). Since then, several state utilities have been privatized. The states were able to privatize these distribution companies before the new framework for the electric power sector had been fully established because their concession contracts included rules for tariff readjustment, thus eliminating the biggest uncertainty from the investor's perspective.

After the new concession laws (Laws 8,987 and 9,074) were approved in 1995, concession contracts could be based on the principle that tariffs would be adjusted when the "economic and financial equilibrium" of the contract was affected by an increase in costs, in other words, naturally-occurring cost increases would be passed on to consumers. This principle was adopted in the first privatization in the power-sector, the sale of Escelsa, in mid-1995.

The concession contract for Escelsa, however, did not explicitly define the parameters for adjusting tariffs. Neither did it clearly state whether productivity gains would be transferred to the consumers. Consequently, the omission from Escelsa's concession contract implied that every year intense and possibly rancorous negotiations would occur between the company and the regulator, a burdensome and time-consuming process [Gomes and Monnerat (1996, pp. 8-10)].

These uncertainties were eliminated with the concession contract for Light, the second federally owned distribution to be privatized. In this contract, the concept of the "price cap" (not just an upper limit, but a full price adjustment mechanism) was clearly adopted. Under this plan, tariffs are subject to an annual *readjustment* that is linked to inflation as measured by a general price index. In addition, a periodic process of tariff *revision*, in which the mathematical inflation linkage itself is subject to change, also occurs. In the case of Light, revisions will be conducted every eight years.

After the privatization, initial tariffs were set so as to guarantee the “economic and financial equilibrium” of the concession, as were the annual tariff readjustments. Up to the eighth year, the productivity gains are absorbed by the company. After the eighth year, the tariff revision can establish some percentage x that will be deducted from the annual price readjustment, so as to transfer some fraction of the productivity gains to the consumer. Implied in this procedure is that the x factor will be zero for the initial eight-year period.

The price-cap mechanism has the advantage of stimulating the company to pursue productivity gains in excess of the x factor, since it will be fixed for the period between tariff revisions. Still, some doubts remain as to how the revision will be done, since the concept of economic and financial equilibrium could be interpreted to represent the kind of return on equity seen in capital markets at the time of the privatization, or at the time of the revision. Also unclear is what could happen if inflation were to reach very high levels, since the tariff readjustments will be made annually [Gomes and Monnerat (1996, pp. 14-15)].

The adoption of the price-cap concept, however, was the key step that paved the way for privatization of the state-owned distribution companies. The terms of these sales have typically called for a revision period of four or five years.

The first process of tariff revision for Escelsa was concluded in August 1998. The company’s tariffs were reduced by 3.4 per cent on average. Since this company is the only privatized utility not subject to a price-cap scheme, the tariff level now in effect will remain operative until the next tariff revision. Escelsa’s tariffs are also readjusted yearly for inflation.

7. Restructuring of the Electric Power Sector at the State Government Level

As mentioned earlier in this article, the centralized model theoretically left for state governments only the ownership of distribution companies. There were, however, major exceptions to this rule. Eletrobrás, as a federal holding company, owned two distribution companies (Escelsa and Light), which were the first to be privatized.

More important, though, state governments owned four major vertically integrated companies: Cesp, Cemig, Copel and CEEE, which belonged to the States of São Paulo, Minas Gerais, Paraná, and Rio Grande do Sul, respectively. These companies not only were responsible for 34.7 per cent of total generating

capacity in 1995 (see Table 1), but also owned strategically placed transmission assets in Brazil's most important industrialized regions. Most significant, however, state-owned utilities accounted for the majority of the Brazil's distribution assets. (By implication, the financial crisis afflicting the states was the first reason why privatization of distribution assets has advanced further than for generation and transmission assets.)

São Paulo was the first state to announce its intention to restructure and privatize its electric power sector; this announcement was made only three months after the new administration took office in January 1995. The restructuring comprised its three utilities, Cesp, its subsidiary CPFL, and Eletropaulo. The original plan called for unbundling the companies and splitting them into as many as 20 gencos, transcos, and distribution companies.

The privatization was widely viewed as the only viable outcome for both the financially desperate utilities and the state government. Both Eletropaulo and Cesp inherited huge levels of indebtedness from the government and had even accumulated arrears in their energy purchases from Eletrobrás (including the energy acquired from Itaipu). Despite these obstacles to privatization, however, the Restructuring Plan for São Paulo State was guided by a long-range vision: the creation of a competitive environment for the electric power sector – an important step for a state that is responsible for around 40 per cent of the country's industrial production.

The state privatization law was approved in 1996 and consultants were immediately hired to model the privatization. Their initial recommendation was to sell CPFL first, since it was primarily a distribution company. Eletropaulo was split into four different companies: a genco, a transco, and two distribution companies. The government decided not to privatize the genco, since its two major power plants (one hydro and one thermal) are hampered by environmental problems. The state privatization law forbid the majority privatization of the transco, but did allow the sale of 49 per cent of its voting capital.

The government tried to privatize the two distribution companies (Eletropaulo Metropolitana and Eletropaulo Bandeirante) in April 1998, but succeeded only in selling the former. In mid-September 1998, Eletropaulo Bandeirante was successfully privatized on the second attempt.

The restructuring of Cesp was far more complex because it involved the privatization of generation assets. Ultimately, the company was split into six pieces: four gencos, one transco, and one distribution company. The distribution company, named Elektro, was successfully privatized in June 1998. The generation companies should be privatized after this year, since the state

government decided to wait for the enactment and implementation of the regulation related to the new model for generation and transmission of electric power.

The State of Rio Grande do Sul also implemented a program to restructure its only electric power company, CEEE. The main goal of the restructuring plan was to improve service quality, but reducing costs and increasing investment were also objectives. The restructuring of CEEE was implemented by breaking it up into six new companies: two gencos (one hydro and one thermal), one transco, and three distribution companies. Of these, only two of the distribution companies were privatized in late 1997, while the state government retained control of the third. The government also will not privatize the transco and the hydroelectric genco, but the thermal genco could be transferred to the federal government under negotiations to reschedule the state's debt.

To date, the States of Minas Gerais and Paraná have not decided to privatize Cemig and Copel, which are considered to be the best performing state-owned utilities in the country. Instead of privatizing Cemig, the State of Minas Gerais decided to forge a strategic partnership with a foreign utility. In May 1997, a consortium formed by Southern Energy International, AES (a US utility), and local pension funds acquired 33 per cent of Cemig's voting shares, gaining the right to appoint four of the eleven seats on the company's Board of Directors.

The partnership agreement emphasizes building high-return projects and cutting costs, and calls for a more aggressive marketing strategy for the company. Dividends can also increase up to 50 per cent of the company's net income if its cash flow is strengthened. Also, the company is moving to create three separate subsidiaries for its generation, transmission, and distribution operations by the end of 2000, having already completed (at the end of 1997) the accounting separation of these three segments.

8. Results and Perspectives of the Privatization of the Electric Power Sector

Table 4 summarizes the results of privatization auctions in the electric power sector up to September 1998. A total of 16 distribution companies have been sold so far, as well as two hydropower plants (Cachoeira Dourada and Gerasul).⁵ Total revenues so far have totaled US\$ 20.7 billion, of which US\$ 3.8

5 Previously owned by the State utility Celg, the Cachoeira Dourada power plant was sold with a 15-years PPA agreement with Celg, which will be the only buyer of its energy in the first five years. In the next 10 years, the purchases will be reduced at an yearly pace of 10 per cent.

billion has gone to the federal government and US\$ 16.9 billion to the state governments. This amount also includes the sale of US\$ 1.7 billion of minority equity in various distribution companies; included in this figure is the US\$ 1 billion paid for the one-third stake in Cemig.

After the adoption of the price cap removed investors' concerns about tariff adjustments, the privatization of state-

Table 4
Results of Privatization Auctions in the Electric Power Sector

<i>Company</i>	<i>Sale Date</i>	<i>Bid Value (US\$ Million)</i>	<i>Premium (%)</i>	<i>% of Total Capital</i>	<i>Company Value (US\$ Million)</i>	<i>Sales (GWh/Year)</i>	<i>Group which Has Acquired the Control</i>
Distribution							
Escelsa	07-12-95	385	11.78	50.00	770	5,487	Iven and GTD (Brazil)
Light	05-21-96	2,217	-	50.44	4,395	21,689	EDF (France) AES (USA) Houston (USA)
Cerj	11-20-96	588	30.27	70.26	837	5,733	Chilectra/Enersis (Chile) EDP (Portugal)
Coelba	07-01-96	1,602	77.38	62.54	2,561	7,985	Iberdrola (Spain) Previ (Brazil)
CEEE Centro-Oeste	10-01-97	1,372	93.55	90.91	1,510	5,772	AES (USA)
CEEE Norte-Nordeste	10-21-97	1,487	82.62	90.75	1,637	4,611	VBC (Brazil) CEA (USA) Previ (Brazil)
CPFL	11-01-97	2,741	70.15	41.06	6,615	16,704	VBC (Brazil) Bonnaire (Brazil)
Enersul	11-19-97	568	83.79	48.67	1,167	2,513	Escelsa
Cemat	11-27-97	356	21.09	86.91	406	2,139	Grupo Rede/Inepar (Brazil)
Energipe	12-01-97	525	96.05	86.42	596	1,492	Cataguases-Leopoldina (Brazil)/CMS (USA)
Cosern	12-01-97	616	73.90	85.75	718	2,084	Iberdrola (Spain) Previ (Brazil)
Coelce	04-02-98	868	27.20	53.11	1,635	4,778	Enersis (Chile) Endesa (Spain)
Eletropaulo Metropolitana	04-15-98	1,776	-	29.80	5,960	34,779	EDF/AES/Houston
Celipa	07-01-98	388	-	51.26	761	3,014	Grupo Rede/Inepar (Brazil)
Elektro	07-16-98	1,273	98.90	46.62	2,731	10,295	Enron Brazil Power Holding
Eletropaulo Bandeirante	09-17-98	860	-	29.80	2,885	23,170	CPFL/EDP
Generation							
Cachoeira Dourada	09-05-96	663	43.49	78.88	908	3,820	Endesa/Enersis
Gerasul	09-15-98	801	-	42.10	1,904	19,815	Tractebel (Belgium)
Other Companies* (Minority Shares)		1,676					
Federal Companies		3,403			7,068	46,991	
State Companies		15,681			30,925	128,889	

* Includes US\$ 410 million from minority shares held by Eletrobrás, and US\$ 1,053 billion and US\$ 213 million from the sale of minority stakes on Cemig and Copel, respectively.

Source: Citibank.

owned utilities proceeded quickly, especially because most of the utilities sold did not require prior restructuring, except in the aforementioned cases of CEEE, Eletropaulo and Cesp (Elektro). More than 50 per cent of the country's distribution facilities are now in private hands.

The cash-starved condition of the state governments constituted an additional impetus for privatization at the state level, which the federal government further stimulated in two ways. First, BNDES would extend revenue-anticipation loans to state governments which approved privatization laws, taking as collateral a controlling equity block of the utility or utilities being privatized. If the state government did not subsequently privatize the company, BNDES would call the loan, seize the shares, and privatize the company anyway.

In some cases, the agreement involved directly transferring the control of the company to Eletrobrás, for latter privatization. A number of distribution companies were federalized in these schemes, as Cemat, Enersul, Celpa, Ceal, Ceron, Cepisa, Electroacre. The first three have already been privatized.

The second incentive provided by the Federal Government was related to the overall process of debt rescheduling between the state governments and the Federal Government. In this process, state governments were offered favorable terms to reschedule their debts, including a thirty-year term and subsidized interest rates. The rescheduling, however, included only 80 per cent of the outstanding debt, with the remaining 20 per cent paid up front in hard assets. The only option for most governments was to give the Federal Government control of their public companies, or the revenues they obtained from privatization.

While the state debt rescheduling was clearly a macroeconomic policy related to the public sector fiscal balance, it had the positive side effect of accelerating the privatization of the state distribution companies, since, as noted previously, the states controlled a relatively high proportion of distribution assets. Privatizing distribution companies first was viewed as a crucial step not only in selling off the gencos but also in making IPP projects viable. Since the distribution companies would be the buyers of the energy sold by the gencos and new IPP producers, the credit risk to new investors would be reduced if the distribution companies were already financially sound and under private ownership.

As shown on Table 4, the privatization of the distribution companies has attracted many foreign companies from the United States (AES, Houston, Enron, CEA, CMS), Europe (Electricité de France-EDF, Eletricidade de Portugal-EDP, Iberdrola, Endesa-Spain, Tractebel) and Latin America (Chilectra, Enersis, Edegel and Endesa-Chile). Internally, the major player has been VBC

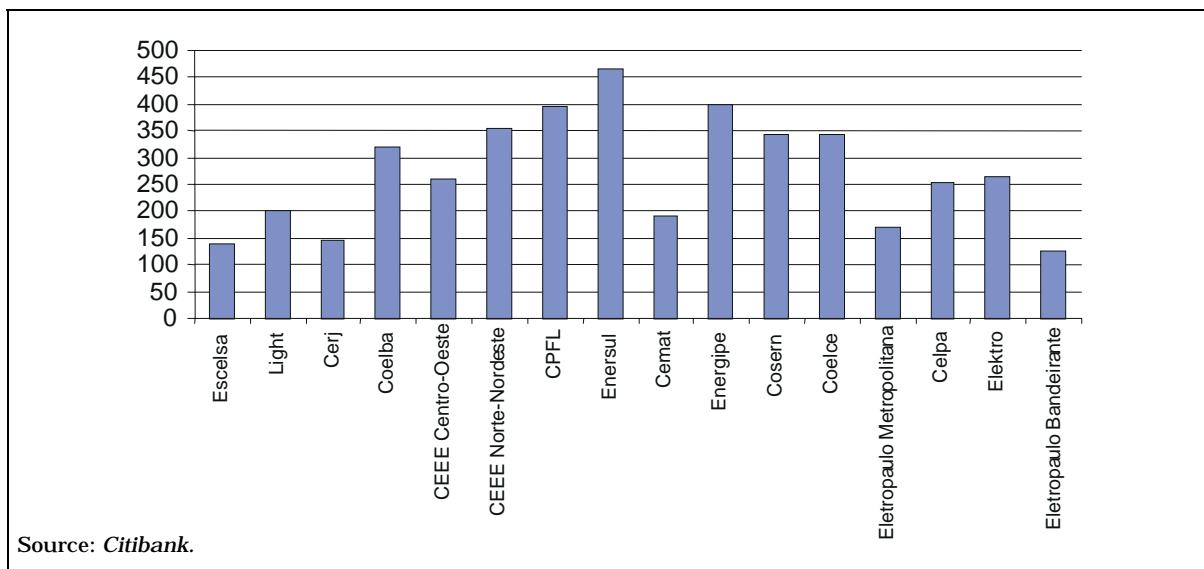
Energy, a joint venture between Bradesco (the leading privately owned bank), Votorantim (an aluminum and cement producer) and Camargo Corrêa (a major contractor). Other domestic players, such as Grupo Rede/Inepar and Cataguazes-Leopoldina, are groups that already were participating in Brazil's electricity distribution activities before privatization.

Another important feature has been the participation of pension funds (especially Previ, from Banco do Brasil) in some of the consortia. Salient examples of pension fund activity are in Escelsa (GTD is a group of pension funds), Coelba, CEEE Norte-Nordeste, and Cosern. It is also interesting to note that, in the latest privatizations, some of the acquirers have actually been companies which themselves had been privatized earlier, such as Escelsa (which bought Enersul) and Light (which acquired Eletpaulo Metropolitana). However, this phenomenon is not likely to become too common, as maximum limits on market share have been established in order to prevent oligopolies from forming.

Graph 3 shows that the prices paid for utilities at auction increased after the initial privatization of Escelsa and Light; in particular, the sales that occurred in 1997 produced healthy premiums. This trend is due to the increasing credibility which the privatization process acquired after the adoption of the price cap mechanism and also to the continuous decline in inflation over the last four years. Furthermore, many foreign companies saw utility privatization as an opportunity to enter the Brazilian market, and were willing to pay high prices to buy their first asset, for strategic reasons.

Aside from providing a domestic presence, utility assets were perceived as a base for financial leverage of other acqui-

Graph 3
Distribution Companies Values per MWh
(In US\$)



tions as the privatization process continues. In cases where distribution companies were being acquired, foreign purchasers were no doubt also aware that profit margins for power distributors were higher in Brazil than in most other countries. The ratio between bulk supply tariff and the retail tariff should ideally be around 60 per cent worldwide, but is 40 per cent in Brazil.

While prices paid in 1998 have generally fallen off from 1997 highs – especially beginning with the privatization of Eletropaulo Metropolitana – the softer market is attributable to the impact of tighter world credit conditions for investment in emerging markets; this factor, as well as related price volatility, has affected the appetite of some players in the privatization arena.

In the future, the privatization of the electric power sector should still provide significant revenues estimated at US\$ 18.9 billion, as shown in Table 5. Most of this will come through the

Table 5
Estimated Revenues from Scheduled Privatizations in the Electric Power Sector – 1998-2000
(In Billions of US\$)

1998		
Celpe	10-Nov	1.00
Total		1.00
1999		
Furnas I	1 st Q	1.80
Cemar	1 st Q	0.70
Chesf I	2 nd Q	2.35
Eletronorte – Isolated System (Manaus)	3 rd Q	0.33
Furnas II	3 rd Q	1.50
Elektro (Minority Shares)	3 rd Q	0.70
Ceron	3 rd Q	0.15
Eletróbrás (Minority Shares)	3 rd Q	0.33
Cesp (Minority Shares on CPFL)	4 th Q	0.30
Eletoacre	4 th Q	0.05
Eletróbrás (Stake on Eletropaulo – 1 st Inst.)	4 th Q	1.35
Ceal	1 st H	0.45
Eletronorte – Isolated System (Acre/Rondônia, Amapá and Boa Vista)	1 st , 2 nd H	0.40
Cesp – Power Plant (Pardo, Tietê and Paranapanema)	1 st , 2 nd H	1.00
Cepisa	2 nd H	0.20
Cesp (49% of Transmission Company)	2 nd H	0.20
Eletropaulo (49% of Transmission Company)	2 nd H	0.12
Total		11.93
2000		
Chesf II	2 nd Q	1.50
Eletronorte (Tucuruí)	3 rd Q	1.50
Eletróbrás (Stake on Cesp)	1 st H	0.50
Cesp (20% owned by Banespa)	1 st H	1.50
Cesp (Generation Assets of Paraná)	2 nd H	1.00
Total		6.00

Source: Citibank.

privatization of the gencos created from Eletrobrás and Cesp. With regard to the revenues accounted for as belonging to the Federal Government, some small distribution companies were federalized prior to their privatization as part of the states' payment from the rescheduling of their debt with the Federal Government

The list presented in Table 5 does not include companies not currently scheduled to be privatized; such companies include Cemig, Copel, Celesc, and others, as well as the transcos and the nuclear assets owned by Eletrobrás. Assuming that most if not all of these assets will eventually be privatized, total revenues from the privatization of the entire power sector in Brazil could easily total US\$ 50 billion at the end of the process.

9. Prospects for Investment in the Power Sector

With the major guidelines for the new competitive model established and the regulatory agencies already functional, the privatization of the Brazilian power sector will proceed in the next two years to the gencos. There might even be some attempt to transfer the ownership of the transcos, although no game plan currently exists for such an effort.

The biggest challenge facing the utility sector is the establishment of a good operating and managerial track record. Positive tangible results will do the most to boost the credibility of the sector and confidence in the privatization model, which in turn should encourage inflows of additional investment sufficient to meet growing demand.

In the latest version of Eletrobrás's Ten-Year Plan, drawn up under the auspices of the GCPS, additional investment needs are estimated using a macroeconomic scenario of moderate growth. However, two alternative growth assumptions can be made. In fact, the most realistic of the three scenarios created is that of low economic growth, under which the GDP would grow 2.8 per cent for the 1997-2002 period and 4.9 per cent from 2002 to 2007.⁶

Under the low-growth scenario, electric energy consumption would still increase appreciably, with total consumption rising from 293.6 TWh in 1997 to 492.9 TWh in 2007, for a yearly average growth rate of 5.32 per. Table 6 summarizes the total investment needed over the next ten years for generation, trans-

6 The moderate-growth scenario posits 4.8 per cent average annual GDP growth for the 1997-2007 period, while the high-growth scenario assumes average annual GDP growth of 5.9 per cent for the same period.

Table 6
Expected Investment in the Electric Power Sector -
1998-2007
(In Millions of US\$)

	<i>1998-2002</i>	<i>2003-2007</i>	<i>1998-2007</i>
Generation	16,599.8	10,362.9	26,962.7
Transmission	11,838.0	n.a.	11,838.0
Distribution	7,502.8	7,942.0	15,444.8
Total	35,940.6	18,304.9	54,245.5

Note: Based on the most recent GCPS version of Eletrobrás's Ten-Year Plan.

n.a.: not available.

Source: Eletrobrás (1998).

mission, and distribution, based on a medium-growth scenario that posits energy demand growth of 5.88 per cent annually (from 293.6 TWh in 1997 to 519.7 TWh in 2007). Over the next five years (including 1998), total investment should reach almost US\$ 36 billion. Even if this amount were reduced under a low-growth scenario to the US\$ 30 billion range, total investment would still average US\$ 6 billion annually through 2002.

As noted earlier in this article, investment in Brazil's electric power sector declined steadily in the 1990s as the power companies were squeezed by their debt servicing requirements and the limited availability of financing. Under the new competitive model established so far, an increasing proportion of total investment will be provided by private investors. Private capital will be especially important for developing new generation and distribution capacity, while investment capital for transmission lines will be primarily furnished by the publicly owned transcos (at least in the medium term).

With most of the hydropower potential in the southern and southeastern parts of the country already exhausted, major hydropower power projects are likely to be feasible only in the North, where development would entail significant environmental costs and high transmission expenses. Consequently, considerable emphasis has been placed on increasing the availability of electric energy from thermal plants (especially gas-fired) operating under IPP schemes.

So far, the use of natural gas in Brazil's energy matrix has been limited by the relative absence of this kind of fuel from the country's known hydrocarbon deposits. Brazil owns only 2 per cent of the natural gas reserves of Latin America. However, some pipeline projects are being pursued to import gas from neighboring Latin American countries. The major pipeline under development is the Brazil-Bolivia pipeline, which should be in operation by the end of 1998. At full capacity, this pipeline will provide 30 million cubic meters/day. Two other pipelines from Argentina into

southern Brazil could increase the availability of natural gas in Brazil by an additional 55 million cubic meters/day.

By increasing imports, Brazil is expected to increase the proportion of natural gas in its energy matrix from 2.7 per cent in 1997 to 12 per cent by 2007. This total includes the use of natural gas in gas-fired thermal power plants. Currently, there are 28 natural gas-fired thermal projects representing an additional capacity of 11,538 MW⁷ planned for construction during the next three to four years in Brazil. This incremental capacity is equal to 55 per cent of the total expansion of generation capacity planned by Eletrobrás from 1997 to 2002, during which total capacity should increase by 20,756 MW (from 59,324 MW in 1997 to 80,080 MW in 2002).

According to the Ten-Year Plan drawn up by Eletrobrás, the marginal cost of energy supply should be US\$ 38/MW, but the price for gas-fired thermal plants could reach US\$ 45/MW. These levels, especially the latter, represent a substantial increase from the US\$ 30/MW level at the end of 1997 (see Graph 2), particularly since the supply rates in the graph include the transmission costs that will henceforth be charged separately. As this discussion illustrates, the tariffs for supplying energy should increase until they reach an international standard of around 60 per cent of the tariffs charged to consumers (up from 40 per cent today).

However, there is evidence that gas-fired thermal plants (especially with combined-cycle technology) could achieve tariffs below the US\$ 45/MW suggested by Eletrobrás's Ten-Year Plan. A project in the State of Mato Grosso had a winning bid of US\$ 41/MW, while two other plants (in São Paulo and Rio Grande do Sul) had bids at US\$ 29/MW. The latter two projects, however, have yet to be started. Since technological improvements in the economic efficiency of gas turbines have been impressive over the last few years, thermal plants will definitely have an increasing role in electric power generation, and should eventually become more cost-efficient than major new hydropower plants.

Despite the generally positive outlook for demand and supply factors, many issues continue to cast shadows on the prospects for attracting sufficient levels of new investment:

- *The weakness of Brazilian capital markets* - In spite of the successful track record of the Real Plan in achieving low levels of inflation, local capital markets remain underdeveloped, as companies continue to rely excessively on international capital markets. In the short

7 The data regarding the natural gas industry in Brazil were obtained from several presentations at the Seminar "Natural Gas: Questions and Opportunities", held in São Paulo in June 1998, sponsored by the business newspaper *Gazeta Mercantil*.

and medium terms, however, prospects are gloomy for capital flows into emerging market countries, especially considering the increase in generic sovereign risk after the Asian crisis and the external debt default in Russia.

- *Regulatory and operational risks* – The new regulatory framework has been established but not yet tested. Investors might be more reluctant to commit resources in the initial stages before seeing how tariff revisions proceed in practice for the current private utilities. Moreover, the new dispatch model also has to show that normal operations do not create conflicts of interest between price-setting in new bilateral contract negotiations and the definition of the spot price in the MAE.
- *Risks associated with the expansion of the transmission system* – Because the transmission companies will continue to be publicly owned, their ability to obtain sufficient resources for needed investment is unclear, especially given the key role that fiscal adjustment (i.e., discipline) should play in Brazilian macroeconomic policy making in Brazil over the next several years.
- *The disparity in energy costs and construction periods* – Under a scenario of low economic growth, there might not be enough incentive to build new thermal capacity if short-term operating costs are not competitive with the old hydropower plants or even with the new hydropower plants. On the other hand, two advantages of building thermal plants are their shorter construction times and lower capital intensity. Despite these advantages, the government could seize on the issue of short-term operating costs in order to justify funding hydropower projects through special loans, thus crowding out thermal capacity [Feldman (1998)]. Such a policy could prove shortsighted if growth were to pick up unexpectedly; moreover, some of the externalities involved with hydropower plants (notably environmental) are usually underappreciated.

Despite these uncertainties, Brazil remains a fast-growing market with great potential for power investments, even after adjusting for the fair amount of risk associated with implementing a new model in its initial stages. A study by DRI/McGraw Hill states that by 2020, consumption in Brazil should grow by 3.5 times, in which case capacity should expand by 124 GW. The study rates Brazil first in investment attractiveness in the electric utility sector [Chazyn (1997, pp. 20-21)].

10. Concluding Remarks

The privatization of Brazil's electric power sector to date has proven to be successful in terms of generating revenue from asset sales, attracting foreign capital to finance the new competitive model, and moving away from an environment in which most of the utilities were plagued by weak results, high indebtedness, and low investment levels.

Moreover, prospects seem to be bright for raising the quality of service to consumers, while making costs more reasonable. Much of this improvement will be driven by anticipated increases in productivity, which privatization appears to be delivering. The framework for increasing investment in new generation capacity also seems to be in place.

However, we should reiterate what we noted at the beginning of this article: the special features of Brazil's electric power sector have required, and have so far been met by, special solutions not employed elsewhere. Therefore, Brazil's privatized power sector will continue to evolve on the basis of learning by doing. For instance, the new regulatory environment has yet to prove its efficiency, particularly in cases where federal and state agencies share responsibilities. Last summer in Rio de Janeiro City, a series of power shortages engendered popular opposition to the recently privatized utilities in that region. In a presumably salutary example of learning (or teaching) by doing, the Aneel eventually fined one of the utilities responsible for the shortages – a sanction that was rarely applied when the utilities were state-owned.

The privatization of the generation assets will constitute the second stage in the privatization of the power sector. This stage will involve efforts to sell some very large assets in the context of limited availability of financing for emerging markets over the next year or two. The extent to which financing constraints should influence the pace of privatization is not clear. As already observed, however, privatization will also depend on the effectiveness of the new dispatch environment and the functioning of the wholesale electricity market; unlike global financial markets, both of these factors are controllable by Brazilians.

The last major hurdle to be overcome is the creation of an environment in which private investors can confidently commit capital to large green field generation projects, whether thermal power or hydropower. Again, financing will be a major issue. In this case, a prerequisite for success will be support from government, either through BNDES or through a newly created Financial Agent for the Power Sector (AFS), which would manage the revolving funds currently administered by Eletrobrás.

Nonetheless, the transformation of the Brazilian electric power sector is under way and is irreversible, for all practical purposes. Some of those who were skeptical in the early stages are now fully engaged in pushing privatization forward. Many questions that loomed large three years ago have since been answered, and the jigsaw puzzle is being assembled, piece by piece.

References

- Chazyn, F. (1997), "Toward a New Approach to Power Project Financing: The Case of Brazilian Distributed Generation", *The Journal of Project Finance*, Institutional Investor Inc., Fall.
- Coopers & Lybrand (1997), *Projeto de Reestruturação do Setor Elétrico Brasileiro*, Executive Summary of the Consolidated Report for Stage IV of the Consultancy Advisory for the Minister of Mines and Energy, Brazilian Government, June.
- Eletrobrás (1998), *Plano Decenal de Expansão 1998/2007*, GCPS, preliminary version, March
- Feldman, R. D. (1997), "Brazil's Power Privatization: Prelude to New Infrastructure Development Actions", *The Journal of Project Finance*, Institutional Investor Inc., Fall.
- Feldman, R. D. (1998), "Brazil: Deregulation and the Future of Project Finance", *The Journal of Project Finance*, Institutional Investor Inc., Spring.
- Ferreira, C. K. L. (1995), *O Financiamento da Indústria e da Infra-Estrutura no Brasil: Crédito de Longo Prazo e Mercado de Capitais*, Ph.D. thesis presented to University of Campinas, September.
- Gazeta Mercantil* (1998), "Natural Gas: Issues and Opportunities", São Paulo, June, various presentations.
- Gomes, F. B. M. and S. B. Monnerat (1996), "A Questão Regulatória nas Privatizações da Light e da Escelsa", BNDES Staff Paper, m.s.
- Oliveira, A. (coord.) (1997), *Perspectivas da Reestruturação Financeira e Institucional do Setor Elétrico Brasileiro*, Research Report sponsored by Pnud/Ipea/Fundap, May.
- Pires, J. C. L. and M. S. Piccinini (1998), *Mecanismos de Regulação Tarifária do Setor Elétrico: A Experiência Internacional e o Caso Brasileiro*, BNDES, Texto para Discussão, julho.
- Santos, M. F. M. (1996), *Sistema Interligado: Benefícios e Encargos*, presentation at the seminar "The Electric Power Sector Reform", Foz do Iguaçu, May.
-
