GETTING PRIVATIZATION RIGHT: ESTABLISHING A COMPETITIVE MARKET FOR ELECTRICITY GENERATION IN BRAZIL

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GETTING PRIVATIZATION RIGHT: ESTABLISHING A COMPETITIVE MARKET FOR ELECTRICITY GENERATION IN BRAZIL

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Getting Privatization Right: Establishing a Competitive Market for Electricity Generation in Brazil

Executive Summary

Recent trends in many countries indicate a desire to move towards competitive markets, rather than state-owned or regulated systems. Encouraging experience in countries such as the United Kingdom has led other countries to explore the possibility of competitive markets, making electricity deregulation one of the most debated policy topics in the 1990's. There has, however, been little experience in establishing competition in hydroelectric systems. The only examples thus far have been Norway which, as a part of the Nord Pool, is not predominantly hydroelectric any more, and New Zealand which has a mixed hydroelectric and thermal system. Brazil, the only example of a major country that relies almost entirely on hydroelectric power, is now in the process of restructuring its electricity industry. Not surprisingly, it faces many questions that are specific to the operation of a competitive hydroelectric market. The popular perception in Brazil is that competition in electricity is inappropriate and probably unfeasible in a hydroelectric system. It is argue that competition will result in much greater inefficiency, possible power outages, further reductions in investments in new generating units and general chaos. This paper attempts to establish a framework under which the issue of competition can be addressed.

1. Overview

Electric utilities in Brazil, as in many other developing countries, are owned and operated by the government, through agencies of both the federal and respective state governments. In addition, there is one generating station, Itaipu, that is jointly owned and operated by the governments of Paraguay and Brazil. In recent years, governments at both the federal and state levels have started investigating the prospects of privatizing the operation of both generation and distribution utilities. To this end, the distribution utilities, Light in Rio de Janeiro and Escelsa in Esprito Santo were privatized in 1995-96. Several companies owned by state governments have since been sold and more auctions are planned for 1997 and 1998. The first generating station, Cachoeira Dourada was sold in mid-1997.

The privatization events in Brazil are by no means unique. Several other countries are in different stages of privatizing their electricity systems, for reasons as varied as lack of government capital for expansion, infusing more efficiency in the electricity industry, raising revenue out of sale to reduce budget deficits, etc. Many countries have been quite successful in privatization and in increasing competition in electricity. One must understand though that privatization and competition are not the same and that without competition many of the benefits of privatization will be lost especially in a country such as Brazil, which has little by way of a tradition of strong regulatory oversight.

The privatization program in Brazil too is concurrent with efforts to restructure the industry so that there is scope for more competition between utilities and more choice for consumers. The federal government as well as some state governments have begun to study the process of restructuring. There is also an effort to establish regulatory authorities to oversee the operation of a privatized market. There seems to be a consensus to lessen government control and ownership of the electric utilities business. However, privatization is not an easy task, more so in Brazil than in other countries.

2. Public Policy Concerns

From a public policy perspective, there are two separate issues with which the government should inevitably concern itself – one is privatization; the other is the overarching question of restructuring – the answer to which can have an even greater effect on the national social and economic goals. The reasons for this are fairly clear. Electric utilities will remain an essential service, and there is a public interest in having reliable electricity supply at reasonable costs. The simple act of transfer of ownership does not provide any assurance of either reliability or fair prices.

Each of the two issues – of privatization and restructuring – needs to be examined fairly and without prior prejudices, realizing that the vastly different characteristics of the Brazilian electricity system may demand new solutions. Privatization and restructuring are not synonymous and need to be answered separately. Contrary to popular belief one can have a state owned system with competition, as in Norway, or a privately owned system without competition, as has been the norm in many developed countries around the world, including the United States.

It has to be clear to policy planners as well as the general public that privatization just means the transfer of some ownership rights from the public to the private sector whereas restructuring means changing of the operating relationships of interested parties in the industry – that of generators with distributors, distributors with consumers, etc.

Deciding whether to privatize or not is often driven by concerns other than the pure economics of the electricity sector. Governments around the world, and even in Brazil, use the proceeds from the sale of state owned enterprises to balance their budgets or reduce public debt. This particular motivation to privatize is not likely to conduce serious thought about enhancing the efficiency of the electricity sector. Thus any possible welfare gains from the change in ownership are either lost or ceded to the private sector in the search for quick money to improve the government's balance sheet.

For many reasons the Brazil's decision to privatize is largely a given, which this paper does not seek to analyze. Instead, this paper will concentrate on issues related to competition, which may or may not accompany the sale of electric utilities. The large share of hydroelectricity in Brazil makes competition a different proposition from other countries, notably the United Kingdom. To start with there are questions about the feasibility of establishing a competitive market, as has been the trend in recent years. Most of the concerns arise from four major areas – a) low marginal costs compared with the average cost of generation from hydroelectric sources, b) interdependence of dams which raises concerns about the optimization of water resource use, c) droughts and other natural events which may lead to a shortage of energy in some years, d) alternate uses of water from dams for irrigation and flood control. Government officials associated with the privatization process are skeptical of the prospect of competition in generation.

3. Summary of Results

In studying competition in the electricity industry it is essential to study both the merits and feasibility of applying tested models of competition from the UK and elsewhere, as well as to consider the theoretical economic principles that underlie the market and develop a new model of competition if necessary. Following is a summary of the conclusions of this paper with respect to the four major issues raised above.

3.1 Pricing of Electricity

Low marginal costs should not pose a real problem so long as there is the threat of shortage in the supply of electricity, in other words a capacity constraint. It is true that on a short term basis, the offer price from each of the dams should equal the marginal cost of operation. But then what really is it? One may think that the marginal cost of operation is restricted to the cost of running the turbines, which is indeed small compared to the fixed costs of the dam. A closer analysis would lead one to also consider the opportunity cost of draining water from the dam. In the event of a shortage, water has an enormous value, which the owners of the dam can exploit to earn profits. In a reasonable competitive system, where entry and exit to the market are not artificially restricted, the owners of the dam would be able to charge a price for electricity that is, on average, as high as the long run marginal cost of operating the dam. To choose prices below the long run marginal cost, they would be restricting market entry, while also reducing profits. If dam owners set prices above long run marginal costs, they would be encouraging other generators to enter into the market, thereby reducing their opportunities to earn a profit.

The fact that dam owners will price their electricity on the basis of some implied valuation for water begs the question – how do dam owners determine their offer price, which is critical to determine a dispatch schedule for the dams. In effect owners calculate the value of water in their dams using the expected value of water inflow, storage and demand. Lower expected inflows would raise the value of water and higher inflows would lower it. The value of water would be zero in a competitive situation where there is an overflow.

3.2 Interdependence of Dams

Interdependence of dams is a more subtle problem that needs more sophisticated analysis. We have already established that there is a value to the water flowing from an upstream dam to a downstream dam. Similarly there is value to the electricity flowing on transmission lines. Since the price of electricity, in most circumstances, is derived from the implied value of water, both electricity and water are analogous.

Since dam owners are expected to be profit maximizing, they would like to avoid having to spill water, or even force someone else to spill water if that ends up costing them something. In the event of excess discharge by an upstream dam, the downstream dam may face a situation

where it too will have to spill water. In that situation, if least cost dispatching is used the downstream dam should resort to offering a lower price for its electricity, thus ensuring that it is dispatched first. Unless the dam is constrained by transmission capacity linking it to the grid, it should be able to run at full capacity. If there is still excess water the dam may have to spill some of it, though one would wonder why other dams are willing to discharge any water without being able to earn a profit on it. The incentives point clearly to a system where each dam will discharge, at the most, only as much water as it can generate electricity. Any discharge in excess of this should not take place unless the dam is forced to discharge water, for example during the rainy season when the inflows are much too large for the dams to be able to either generate electricity from or store.

More importantly, each dam would be extremely unwilling to discharge water if that would reduce the spot price at its location. Not surprisingly, that is the same criteria that makes dams truthfully quote their valuation of water and thus ensures efficient dispatching.

In a world where there is efficient dispatching and where the price of electricity is based upon the value of water, there is no reason to expect that water resources will be wasted. In effect, an uncoordinated market based system, if well designed, should achieve the same resource use efficiencies as the coordinated system currently in use.

3.3 Droughts and Floods

Droughts and other natural events need to be dealt with separately. Quantity risk in a hydroelectric system is large, unlike thermal systems. Hydroelectric systems are fixed energy systems, with the maximum amount of energy being capped at the storage capacity of dams and actual inflows. In drought years the possibility of non-fulfillment of supply contracts becomes a distinct possibility. One must realize, however, that the solution to this is not to have no quantity restrictions at all, as has been suggested.

One can always have some fraction of the average annual generation, say 70 percent, under long term contracts leaving the rest to medium term contracts. These long term contracts will have little or no hydrological risk and an agreed price, which will no doubt be higher than the spot price in a year of good rainfall, and lower in a drought year.

3.4 Alternate Uses of Water

Multiple use of dams and reservoirs, for purposes such as flood control and irrigation, is often cited as a reason for centralized operation and planning of water resources. It is also believed to be a justification for retaining government control, since a market based system would not account for uses other than electricity.

What is ignored from this analysis though is that a market based system that is designed only to account for the cost of electricity will indeed limit itself only to electricity. In order to make the system account for other uses of water it will need to be designed accordingly. A simple economic mechanism for this would be to endow the owners of the dams with all rights over the use of water behind the dam. The government, or other groups such as farmers cooperatives can then buy water, which the owner of the dam should be willing to sell at the economic value of the water.

A system as simple as this in theory is no doubt likely to be fraught with problems in practice, which would make the design of a more complicated system essential. A closer analysis of irrigation and flood control needs may lead to a more complicated system in which property rights over water are divided between the owner of the dam and other interested parties.

As this study shows there is no reason to believe that a market based system will not lead to the same results as a centrally coordinated system. Dam owners will use the same model for pricing electricity that the centrally dispatched system ought to use, for efficiency to be maintained. In addition to the directly efficiency gains, one should always keep in mind the transparency gains from having an independent market where each producer acts in an efficient manner only on the basis of information available to the entire market.

Thus, contrary to popular opinion, it is possible to develop a competitive electricity market in a country that is predominantly hydroelectric. There is a need to acknowledge the role competition plays in ensuring the efficient operation of the electricity market and in promoting the sustainability of privatization in Brazil. This paper shows how this can be done.

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Section I: Overview

Brazil is the largest country in Latin America with an area of 8.5 million square kilometers, roughly equal to that of the USA and a population of 159 million, more than a third of all of Latin America. Brazil also has the largest installed capacity for electricity and the largest annual electricity generation, producing 273.8 TWh in 1996. There are a total of 39.8 million electricity consumers, with an average per capita consumption of 2,031 kWh per year. In 1996, the total generating capacity was 57.2 GW and further capacity additions were planned during the next decade. To provide a comparison, Brazil has a population about 60 percent the size of the USA, while generating capacity is less than 10 percent that of the USA. While this capacity is high when compared to other developing countries and sufficient to meet current demand, shortages are expected in the coming years. It is believed that the current stable macroeconomic regime and rapid growth of the economy will fuel further demand for electricity, thus making investments in new generating assets an imperative.

1.1 The Federal System – Eletrobras

Eletrobras, a state owned company founded in 1962, owns or is responsible for most of the utilities business in Brazil. The federal government owns a 47.5 percent share in Eletrobras, while the remaining equity is owned by a host of investors, which in turn are owned by the federal government. These include the *Banco Nacional de Desenvolvimento Economico e Social* (21.1 percent), the *Federal Savings Bank* (0.8 percent), and the *National Development Fund* (7.8 percent) with others holding 22.8 percent of the equity.

Generation and transmission are primarily the domain of four regional companies largely owned by Eletrobras, who are responsible for operating generating stations and transmission lines and for the transfer of electricity to state utilities. These four companies are *Electronorte (Centrais Electricas do Norte do Brasil SA),* which operates in the center-west/north of the country, *Electrosul (Centrais Electricas do Sul do Brasil SA),* which operates in the south, *Furnas (Furnas Centrais Electricas SA),* in the south east/center west, *and Chesf (Companhia Hidro Electrica do Sao Francisco),* in the North East. In addition two distribution utilities, *Escelsa (Espirito Santo Centrais Electricas SA)* in Esprito Santo and *Light* in Rio de Janeiro

were both owned by Eletrobras till they were privatized in November 1995 and April 1996 respectively. Together the generating assets of Eletrobras accounted for 47.3 percent of Brazil's total installed generating capacity in 1996. Apart from these assets Eletrobras also has a 50 percent stake in the Itaipu plant which accounts for 11.6 percent of the total installed capacity.

1.2 State and Municipal Utilities

At the state level there are 27 electric utilities, including large utilities such as *Cesp (Companhia Energetica do Sao Paulo), Cemig (Companhia Energetica do Minas Gerais), Copel* and *Electropaulo,* in which Eletrobras has an interest as an associate company. Most of these companies are primarily involved in distribution and low tension transmission with a minor interest in generation, though some such as Cesp are primarily generating utilities. *Cemig* and *Copel* are vertically integrated utilities.

In addition to these, Eletrobras also oversees 31 independent municipal and private utilities, responsible for distribution.

Table 1: Summary statistics for electricity in Brazil, 1970-93[1]

	1970	1980	1985	1990	1993	1995	1996
Final energy consumption (toe)	n.a.	122.2	141.3	159.7	175.0	n.a.	n.a.
Installed capacity (MW)	10,329	30,084	40,942	49,056	52,721	55,516	57,232
Electricity Production (GWh)	42,017	129,181	189,340	211,043	237,623	260,678	273,827
Share hydroelectric (%)	87.7	92.4	92.6	96.5	97.4	96.1	95.7
Electricity consumption (GWh)	35,731	114,271	163,277	205,310	227,044	249,882	260,908
Participation of electricity in total energy (%)	n.a.	29.1	35.6	39.5	40.0	n.a.	n.a.
Population (000s)	95,487	121,286	135,042	148,477	156,491	161,790	n.a.
Consumption per capita (kWh)	373	942	1,209	1,383	1,451	1,544	n.a.
Customers (000s)	7,998	16,791	24,099	30,864	35,187	32,675	33,934

1.3 Generation

As is evident from Table 1, Brazil's generating company is dominated by hydropower, with hydroelectric plants accounting for more than 97 percent of the generation in 1993. The

[1] Source: David Kurtz, Electricity Generation in Latin America: Sector Reform and Privatization, Financial Times Energy Publishing, 1995.

remainder is split between a variety of thermal sources such as diesel oil, fuel oil, coal and nuclear and a smaller share of fuel wood, charcoal and natural gas.

The Eletrobras system is responsible for 40 percent of the generation, state utilities for 36 percent and the Itaipu for 19 percent,[2] including purchases from Paraguay. Auto-producers account for 4.7 percent and private and municipal utilities for 0.3 percent. Generation grew by 4 percent in 1994.

Even with such large utilization of hydroelectric resources, large untapped hydroelectric potential of 137,100 MW exists. However, most of these resources are in the center-south/north region of the country. Due to the geographic dispersion of demand and supply building capacity in these regions would require construction of long distance transmission systems. Several generating plants are stuck at different stages of construction due to lack of funds with respective governments. New capacity addition is also severely restrained by environmental concerns. Thus, while hydroelectric resources are plentiful, the ability to use them is limited. In essence the expansion of the generation market will have to come, at least in part, from other fuel sources.

Notable among new sources of fuel is the gas pipeline from Bolivia. Running roughly northwest to southeast, the gas pipeline connects heavy load areas of the states of Sao Paulo and Minas Gerais to rich, untapped gas fields in Bolivia. Naturally, gas power has promising prospects in Brazil. Under the existing electricity system it should not be difficult to introduce gas power as an alternative source of generation. However, cost differences between gas and hydroelectric power will make merging the two forms of energy hard. It will also make it hard to plan efficient capacity addition and to carry out merit order dispatching. Compared to the R$32 per MWh average cost[3] for hydroelectric power, estimated costs for gas power range from R$40 to R$50 per MWh. These estimates depend upon gas prices and the nature of gas contracts that the federal government will offer.

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[2] Brazil's share of installed capacity from the Itaipu is 6,250 MW, which is 11.6 percent of the total installed capacity. However, Brazil consumes 96 percent of the electricity generating from the Itaipu, including a large share of Paraguay's electricity.

[3] Average cost of electricity is calculated by taking the average variable costs of operation and adding to it debt service and a reasonable return on equity, currently fixed at 12 percent, for the owners. Typically, the average variable costs are of the order of R$3-5 per MWh.

1.4 Transmission

In 1993, the federal government set up a national electric power transmission system, *Sintrel*. This followed Decree 915 of September 6, 1993 which granted auto-generators[4], cogenerators and independent power producers access to the transmission system, thus enabling them to carry power to consumers for a fee. It is believed that access to transmission lines will encourage auto-generators, who can then supplement their demands from their own sources as well as sell any excess power to other consumers.

Brazil's transmission network consists of two interconnected grids, one in the north/northeast and one covering the south/southeast/center-west regions, broadly all the area south of the Amazon regions. In the northwestern regions of the Amazon isolated systems with short power lines and small diesel generators supply electricity to the 1.5 million consumers in the region. The southern grid which connects a higher generation and demand area has a more complex network of transmission lines. All plants in the southern region run at a frequency of 60 Hz while the Paraguayan part of Itaipu runs at 50 Hz, making conversion to direct current essential. The southern grid has capacity to carry power on high voltage direct current lines between the Furnas sub-station close to Itaipu and Sao Paulo.

There is no interconnection between the two major grids, though a 1000 MW north-south interconnection is planned to be operational by the end of 1998. Large scale power exchanges between the two grids is not possible. This is despite the fact that the regions served by the two grids have different weather patterns, which may be used to even out supply, which depends upon inflow and storage characteristics of the reservoirs in the system.

1.5 Distribution

State utilities account for the largest share of distribution at 77.7 percent. The Eletrobras system accounts for 11.7 percent while municipal and private utilities account for 2.1 percent.

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[4] Auto-generators are typically large consumers who find it more effective to generate electricity for their own consumption. Granting them access to transmission lines ensures that they are able to use their spare capacity to supply electricity to the market.

Table 2: Demand and revenue by sector (percentages)

	Demand	Revenue
Industry	45.6	35
Residential	26.5	30
Commercial	13.3	18
Government & rural	14.6	17

1.6 Recent Changes

In March 1993, through Law 8631/93, Eletrobras put into effect a number of reforms to modernize the power sector. These include the abolition of uniform tariffs and guaranteed rates of return for power companies. Under an ambitious privatization plan envisioned by President Henrique Fernando Cardoso, many state utilities will also be privatized. As mentioned earlier Light and Escelsa have already been privatized and other distribution companies will follow. *Coelba*, the utility in the state of Bahia was privatized in July 1997. In the next few years hydroelectric generation, at both the federal and the state levels, will be offered for privatization as well. The Brazilian government is carrying out this privatization in conjunction with a program to restructure the industry.

Privatization involves the transfer of ownership from the government to the private sector, generally by one of the two following means. Stock or assets may be sold, so that residual ownership and claims on profits are transferred to the private sector. Alternately, concessions for a fixed period may be handed out with an attached concession fee, which is generally collected annually. At the end of the concession period, ownership of the assets reverts back to the government. Restructuring on the other hand relates to a change in operating relationships between different segments of the industry.

1.7 Scope of Analysis

Privatization, by its very nature, will require the establishment of a regulatory body to oversee those activities that may lead to an economically inefficient or socially undesirable outcome. Brazil, like many other developing countries has little previous experience with regulation. Needless to say, establishing a regulatory agency with a well defined agenda will not be easy. One aspect of the privatization program, however, can help make the task easier. Some possible structures of the electric utilities industry can ease the burden of regulation, while still

ensuring that all of the economic and social objectives of the nation are adequately met. By simplifying the task for a regulatory body and, at the same time, exploiting the advantages of operating an efficient competitive market, Brazil can leap over intermediate stages in restructuring. Given unfavorable prior experience with regulation in other countries, it is advisable to reduce the burden for the regulatory agency as far as possible.[5] The success of an efficient privatization lies not in the process or the means undertaken for privatization. The key factor is how much competition is introduced into the market. Regulation, it must be kept in mind, is intended to correct a market failure, rather than to create a command economy.[6]

The following sections outline various possibilities for a restructured industry. Section 2 contains a description of various models available for restructuring and concludes that a competitive market for electricity is both desirable and required for restructuring. Section 3 contains an analysis of the feasibility and design of a spot market. Section 4 sets out some recommendations for the government, including an agenda for further study prior to a major privatization exercise.

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[5] Even in the United States, which has a long tradition of independent regulation, it is generally recognized that regulations often deviate from principles of efficient market operation. Regulation is a tedious process and often lags technological and economic change. In fact regulation may end up inhibiting technological change, as demonstrated by environmental regulation around the world.

[6] See Stephen G. Breyer, Regulation and Its Reform, Harvard University Press, 1982 or Alfred E. Kahn, Economics of Regulation: Principles and Institutions, MIT Press, 1988 for a general theory of the motivations for regulation.

Section II: Alternative models of industry structure

The electric power industry has developed in different countries along different lines, based upon the legal and political situation in each country. The industry structure in each of these countries is a result of the forces of history and drawing comparisons between them may not be fair. However, industry structure can be divided into three broad categories based primarily upon the level of competition – vertically integrated utilities, monopsony buyer and competitive markets.[7] Ownership, grid access and pool arrangements are important factors that define industry structure.

2.1 Model 1: Vertically Integrated Utility

Most prevalent among all the models is the vertically integrated utility model. Until the end of the 1980s this was almost the only industry structure around the world. Typically, in the vertically integrated structure, each utility has a franchise area for which it is obliged to own and operate sufficient generation, transmission and distribution capacity to meet all demand. This industry structure is a result of concerns about electric utilities being natural monopolies.

In some countries the vertically integrated utility has also been publicly owned. In other countries, such as the USA, independent regulatory bodies were established to oversee the operation of investor owned utilities. The problems with both of these options are too well known to merit much discussion here. However, some aspects of the problems need to be highlighted as they become important later.

In its purest form, the vertically integrated utility model, with exclusive franchise areas optimizes both short and long term operation over their exclusive areas. For example, in a situation where two adjoining utilities are not allowed to trade between themselves, each will end up optimizing capacity addition and generation in its franchise area. If the two areas are substantially different in their supply and demand characteristics, this may lead to different

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[7] The classification here follows from Sally Hunt and Graham Shuttleworth, Competition and Choice in Electricity, John Wiley & Sons, 1996. Hunt and Shuttleworth define four alternative industry structures, though the distinction between Model 3 and 4 in their case is in the level of competition in distribution. Model 3 relates to wholesale wheeling while Model 4 relates to retail wheeling. The competitive market structure in this paper draws heavily from the research work of William W. Hogan.

prices in the two markets, signaling inefficient operation of the combined system. Realizing this problem many countries allow utilities to trade bulk power between franchise areas. The structure of trading arrangements determine whether the price at which trade actually takes place covers the fixed costs of operation.[8]

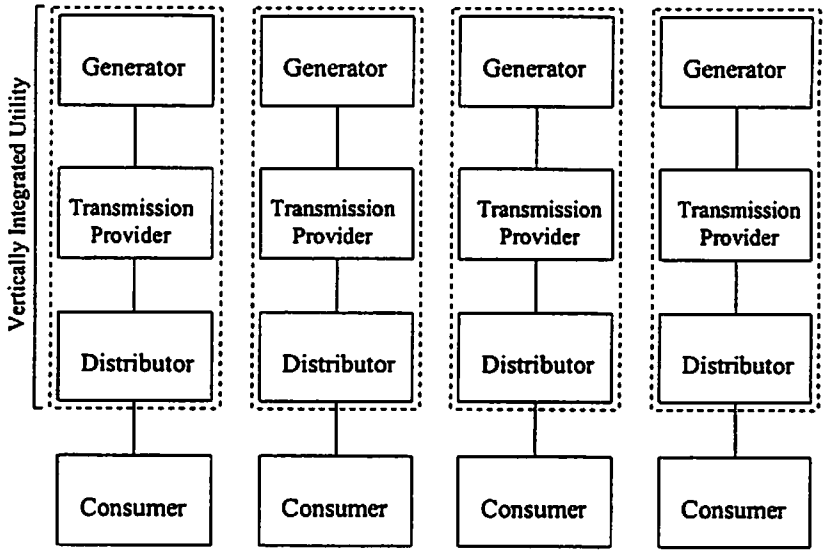

Figure 1: Vertically Integrated Utility (dotted lines denote the domain of the firm)

The other major problem in the vertically integrated structure is that of over or under optimal investment in capacity additions. In the case of regulated privately owned utilities, this is better known as the Averch-Johnson effect.[9] If the regulated rate of return is higher than the capital cost to the utility there is an incentive to over invest, often in less productive assets. The utility has little incentive to reduce operating costs or to adopt new technology that would reduce average costs. In the long term, this would mean that the utility may end up pricing electricity at

[8] For example, in Sweden the Joint Operation Agreement states that each utility is required to meet its power and energy demand either through its own resources or through long term contracts. Utilities were allowed to trade power at variable costs only. All utilities participating in joint operation should meet the fixed cost in their generation systems. This is a typical example of a "partial cost" pool. The system works well when most of the electricity is sold under long term contracts and the pool is used only to correct imbalances between demand and supply in the very short run. As we will see later, the system in Brazil does not provide the same incentives to operate under long term contracts.

[9] Harvey Averch and Leland L. Johnson, Behavior of the Firm Under Regulatory Constraint, American Economic Review, December 1962, pp. 1052-1069

above replacement cost in order to recover its investments in less productive assets. This problem led to the Public Utilities Regulatory Policy Act (1978) in the USA, which obliged utilities to purchase electricity at "avoided costs," thus giving birth to independent power producers (IPPs).

On the other hand many countries, especially developing countries, whether with privately or publicly owned systems, adopted low prices for final sales to consumers, thus making it difficult for utilities to cover their fixed costs and build new capacity. Low prices may mean an explicit subsidy from the government for operation and new investment. The more common case though, is one of implicit subsidies for investment in new capacity even though revenues from sale of electricity may not be enough to recover investment costs.

Brazil has had similar problems with implicit subsidies to vertically integrated utilities, though it has had a remarkable performance with respect to the traditional problems associated with such structures – operation of generation utilities has been remarkably efficient. Since utilities are publicly owned, capacity additions have been the responsibility of government agencies. In cases where the investment required for capacity additions were higher than revenues would justify, taxation and government guaranteed debt were used as instruments for raising capital. Current inability to invest in capacity additions has prompted the government to pursue at least a partial privatization of the system.

Though the industry structure in Brazil is not strictly the same as this model, many similarities remain. Contracts between generation, transmission and distribution firms are centrally mandated, with a heavy hand from Eletrobras. Prices at which transactions take place between regional utilities have little basis in market economics. Retaining the same relationships, which lead to a *de facto* vertically integrated structure will require extensive regulation of the private utilities, since the vertically integrated structure amounts to a regional monopoly. The traditional argument in favor of a vertically integrated structure – natural monopoly – does not hold in the case of Brazil. Generation has some network economies, though no discernible economies of scale. This makes it hard to justify a vertically integrated structure and provides a good reason to move to one of the other two models defined here.

2.2 Model 2: Monopsony Buyer

Several countries that have permitted the operation of independent power producers follow this model, which is by far the most popular model currently among developing countries. Under this structure independent power producers are permitted to sell electricity to a purchasing agency. Since the IPP has no direct access to transmission lines or consumers, it must sell all of its electricity to the utility in the region, which becomes the purchasing agency. Since the utility is the only buyer the market has a monopsonic structure, with the utility retaining price-making capabilities. Elaborate long term contracts are required to assure returns on the IPPs fixed investment.[10] Generally these contracts, known as power purchase agreements (PPAs) cover variable costs based upon actual sales and fixed costs based upon availability of the plant (investment).[11]

This model is a small improvement over the vertically integrated utility model in that it allows for some competition in generation. If a competitive bidding process is followed for new capacity, it is hoped that the cheapest form of energy will be available, at least at the time of bidding. In addition the purchasing agency dispatches electricity based upon marginal costs of operation, which would provide for efficient economic operation of the system, irrespective of the capacity charges the buyer pays. Since the contract price is spelt out in advance, the IPP has the ability to earn a higher return on its investment by efficient management of costs that are not directly passed through, for example by maintaining a portfolio of cheap debt.

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[10] These contracts, by their very nature, are incomplete since they cannot spell out all possible future states of the world under which they are applicable. Much has been written about incomplete contracts and the bargaining associated with them. Bargaining, more than anything else, determines the way any unallocated surpluses, such as unforeseeable profits (or losses) due to changes in technology or legal structures, are divided between the parties to the contract. For a theoretical discussion on incomplete contracts, especially use of property rights as a method for determining contract outcomes, see Oliver Hart, Firms Contracts and Financial Structure, Clarendon Press, Oxford UK, 1995, Ch. 2-4. In most cases, as is borne out by experience, the monopsony buyer has far more bargaining power than the IPP, thus leading to severe problems.

[11] IPPs are often said to be "must run facilities" because of capacity charges that are due, independent of whether generation actually took place. However, a closer analysis shows that capacity charges are just a way of assuring IPPs of a return on their investment, which would otherwise have been a problem given the presence of a monopsony buyer.

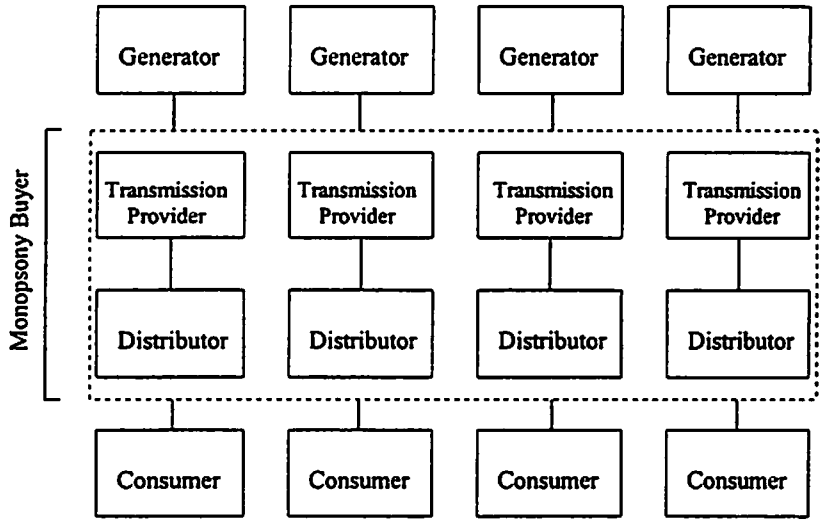

Figure 2: Monopsony Buyer (dotted lines denote boundary of the monopsony buyer) [12]

This model, however, still requires the purchasing agency to monitor the IPPs' variable costs. Previous experience with this kind of monitoring, especially in rate of return regulation for vertically integrated utilities has not been encouraging.[13]

The monopsony buyer model also has severe problems with the creditworthiness of the buyer and enforceability of the PPA. In addition, since the terms of sale of electricity are set out for a long period of time, there is relatively less flexibility to change system characteristics as new technology becomes available, or fuel price changes. Besides, this model of industry structure only partially addresses issues of competition in generation. It still requires almost the same level of regulation of all short term activities, such as production decisions, ratemaking, etc. The government must still oversee all variable costs. The only function that is now

[12] It is not necessary for the monopsony buyer to own transmission and distribution assets, though that is generally the case. In some cases the monopsony buyer may own only the transmission company, while distribution remains with other companies.

[13] Incidentally, this was one of the major problems with the Dabhol plant in India, with Enron as the lead developer. The monopsony buyer has no direct control over the IPPs operating costs, such as fuel, even though it is liable to pay those in full. The contract Enron renegotiated with the Maharashtra State Electricity Board, the monopsony buyer in this case, includes provisions for penalties in case Enron buys fuel at prices higher than those prevailing on world markets.

performed competitively is capacity addition. This model also does not address the issue of competition in distribution and efficient pricing of transmission.

The monopsony buyer model is not a sufficient solution, especially in the presence of better alternatives. A more complete solution would introduce competition for short term generation. However, any industry structure that deviates from the norm of state-owned or regulated industry is a paradigm shift in the nature of operations of the electric power industry. Government regulation does not disappear by making the market more competitive, though it changes form. Regulation in a market system would focus on control of market power, entry and exit.

The search for a better alternative that optimizes short term operation through competition, thus achieving the lowest variable cost, in addition to capacity addition, which minimizes capital costs would lead to a more market based structure open to competition. This is what would be required to ensure that the electricity network operates efficiently and represents the optimum choice for Brazil.

2.3 Model 3: Competitive Markets

The newest model of industry structure is one where competition is also introduced in distribution. Changes in technology have reduced the size at which economies of scale can be fully exploited in generation. With this, and with the realization that most of the electric power industry is not really a natural monopoly has led to an increased interest in opening up the industry to more competition. Problems with implementing the monopsony buyer model for a prolonged period also make it pertinent to explore a third, more competitive option.

Under a competitive market, generators have access to transmission lines over which they can transport power, for a fee, to any customer they choose. Competitive markets in turn may be restricted to wholesale competition or may go all out to provide competition at the level of retail customers.[14] The customer in turn has a choice among a number of generators. This

[14] The distinction between retail competition and wholesale competition is important. However, for the purposes of this analysis, where the only aim is to investigate the feasibility of a competitive market for generation, much of the subtleties of retail versus wholesale competition can be ignored.

market, in essence has many of the properties of markets for other goods, where competition is the key to efficiency.

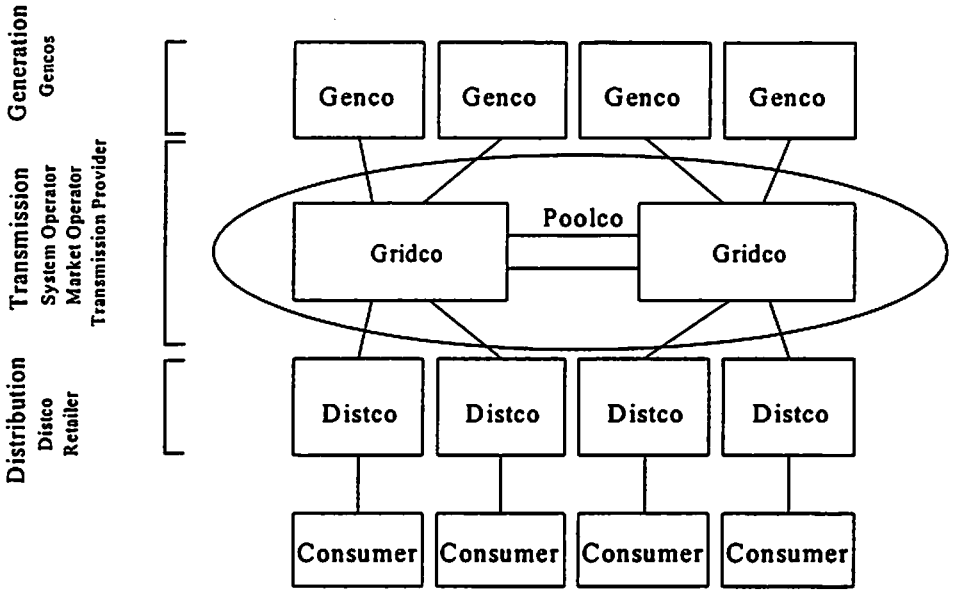

Figure 3: Competitive Markets[15]

A clearer definition of this model of industry structure merits some discussion about the agents in the market. Several alternate models emerge within this broader category depending upon which agents are active in the market and what roles they play. A stylized competitive industry model would include (most of) the following.

Genco – is typically a firm or a division within a firm with ownership or usage rights over a generation facility.

Distco – is a firm that has ownership or usage rights over low voltage wires that connect directly to consumers.

Retailer – is a firm that performs merchant functions of buying electricity from Gencos and selling to consumers, using wires belonging to the Distco.

[15] This market structure is attributed to William W. Hogan, Harvard Electricity Policy Group.

Consumer – a final user of electricity. This may be a residential consumer with a few kilowatts of load or a large industry with several megawatts of load.

System operator/dispatcher – is a firm/agency with access to high voltage wires, voltage and frequency support and reserve energy, that keeps the transmission system stable, with proper frequency and voltage. The dispatcher ensures that overall system generation is undertaken on an economic basis by monitoring least cost or merit order dispatch.

Transmission provider – is a firm that owns high voltage wires, over which electricity is transmitted for a fee.

Market operator[16] - corrects short term imbalances in energy, inevitable and even desirable for efficient system operation, by actual trades on the market. The market operator is also responsible for trades and settlements.

Spot market - is a market or exchange where buyers and sellers of electricity bid to establish a spot price for electricity on a time-differentiated basis. Sellers quote prices at which they are able to supply a certain amount of electricity into the market at a certain time. Out of all the quotes, the market operator develops a supply curve. Similarly buyers quote a price at which they are willing to buy a certain amount of electricity, out of which the market operator develops a demand curve. Trades will take place so long as the demand price remains higher than or equal to the supply price. It must be kept in mind that the special nature of the electricity system prevents the effective operation of a large scale bilateral market. Spot markets and a pool based operation help overcome the technical problems associated with system stability.[17]

Gencos generate electricity and sell it either under long term bilateral contracts to a Distco, Retailer or Consumer, or to anyone who will buy from the spot market, including all of

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[16] It is necessary to distinguish between market operator and system operator at this stage. The system operator is responsible only for optimal operation of the system and has the ability to buy energy to correct imbalances in the system. The market operator, on the other hand, is responsible for actual operation of the spot (and futures) market, including trading and settlements. Separating the system operator from the market operator has its disadvantages – harder coordination of the system, and advantages – better use of different skills.

[17] The creation of a spot market should go hand in hand with the creation of a futures market. In effect, the lack of a futures market will lead to informal futures trades. In some sense bilateral contracts are a result of the lack of long term futures markets.

the above categories as well as other Gencos. To access their consumers Gencos need access to transmission lines and to the short term Spot Market.

The transmission provider transports energy from the Genco to the point of sale to either a large consumer or to a Distco, which will then transmit electricity to smaller consumers. Several transmission providers may exist, though there should be a central System Operator, in charge of merit order dispatching, i.e., to ensure that the lower price suppliers get to sell their electricity first, and to keep the transmission lines stable. Since each Genco must supply electricity to meet its contractual obligations, it may either sell its own power or buy power from other generators on the short term market. Note that if the Genco persistently does not have the capacity to meet its contractual obligations it ends up serving a merchant function, i.e., of acting as a power marketer without generation resources.[18]

Market Operators perform the function of actually estimating and requisitioning supply on the short term market. They are also then responsible for market settlements, after trade actually takes place. In that sense their operations require the skills of clearance houses and stock market operators. System operators may not be the most suitable to perform these functions. However, the separation of dispatching from market settlement entails some loss of operational ease. Despite operational difficulty, separation of system and market operations helps avoid conflict of interest problems. Gains on this count likely overweigh losses from operational separation.

The benefits of competitive markets are many. Competitive markets provide incentives for both short term operation and long term investment optimization. They require relatively less regulation and restrict the role of regulation to market failures, such as information asymmetries. More than anything else, competitive markets place the onus of profit earning upon the managers of the utilities, rather than on the wishes of the regulators or, in most cases, government agencies. This ability to achieve optimal operation of the electricity system through time-tested means of competition is something that needs to be thoroughly investigated in Brazil. If, in fact,

[18] A Genco that is committed, through contracts, to supply far more than it can generate can be viewed as consisting of two separate parts – a Genco with contracts roughly equal to its generation capacity and a merchant seller that performs a function of bringing buyers and sellers together. The merchant seller

it were possible to set up a competitive market the benefits would far outweigh any concerns of transition to a different system.

Competitive markets, despite their elegance in economic theory, are sophisticated and difficult to manage. In a perfectly competitive world with low fixed costs and storage possibilities, as is the case with most commodities, almost all trade in electricity would take place on a short term market, making the market relatively simple. High fixed costs make it almost necessary for Gencos who invest in long term assets to have at least some of their generation covered by long term contracts, generally bilateral contracts that are tailor-made to suit both the seller and the buyer. Short term markets would be required in order to settle imbalances on bilateral contractual obligations.

Determining the price on the short term market, and identifying which generators will be dispatched at any given time is in itself a difficult task. Startup and shutdown may take a long time and be expensive, leading prices in the short term to deviate from both marginal and average costs of operation. However, solutions exist to these problems and these markets have been tested and found to be feasible in other markets, albeit those with a predominance of thermal generators.

The problem then is to investigate the feasibility of a competitive market in Brazil. Would a competitive market operate as a partial cost pool at marginal costs or would it also cover fixed costs in a total cost pool. The biggest apprehension in moving to a competitive market is that fixed costs may not be recovered under competitive prices. That would almost certainly be the case if the market operated as a partial cost pool,[19] covering only the marginal costs of operation.

A partial cost pool does not mean that a competitive market is unfeasible, though it does restrict access to the market for those firms that are not, in some other manner, responsible for fixed costs. The ideal world would be one where anyone who qualifies under a set of basic

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will likely be exposed to risks of both demand and supply, beyond its control, except by careful management of its contracts.

[19] This follows from footnote 3. In the Brazilian system, the marginal costs are a small fraction of the average (financial) costs of generation. Fixed costs in setting up the plant, i.e. through debt service and reasonable return on equity comprise most of the costs.

creditworthiness criteria is allowed to trade on the market, since that permits the creation of a broad market. Understandably, not all creditworthy individuals or firms are responsible for fixed costs. For example, a consumer or a power marketer is not responsible for fixed costs in the same manner as a generator. If the consumer is allowed to operate in the market it is clear that he will constantly be able to buy electricity at prices lower than average costs, while the sellers, namely generators, will have no source of revenues to cover their fixed costs. What structure the industry will finally take, in terms of defining who actually can be called a consumer and who has access to short term markets, depends largely upon the kind of power pool that is feasible.

Nevertheless, low marginal costs of operation and high average costs make the operation of a spot market tricky. Since there is no financial cost of "fuel" in a hydroelectric system, marginal costs are bound to be low, while average costs still remain high due to the large upfront investment required to establish dams. Marginal costs remain almost constant through the year, since they consist of the costs of operations and administration of the dams. Thermal systems on the other hand have significant marginal costs that rise as more capacity is utilized. The operation of a spot market in that case is relatively simple. Plants with lower marginal costs supply electricity to the market first, while those with higher marginal costs supply when market demand exceeds the capacity of low marginal cost firms. Typically, coal plants have lower marginal cost but higher fixed costs than gas plants. In a system that is a hybrid of coal and gas plants coal plants tend to be base load plants whereas gas plants tend to be peak load plants.

The relative ease and cost effectiveness of switching a hydroelectric system on and off also adds a special system characteristic. In particular, the spot market is likely to be very elastic,[20] compared with those in other countries, thus raising different concerns. The following section deals with the economics of establishing a spot market.

[20] As we will see later in Section III, the market operates in such a way that the economic value of water is equal across all dams. A small, temporary increase in price should lead to a large amount of generation becoming available.

Section III - Economic Feasibility of a Spot Market

Before analyzing the spot market, a brief analysis of system optimization is in order. Brazil already has an elaborate system of optimization of water resources, which has worked well in the past. Capacity planning for electricity is done on the basis of a ten year plan to keep the probability of shortage of supply at less than 5 percent. Though shortages are rare, one such shortage led to extensive power failures in April, 1997.

The plan of operation[21] lays out the methodology and criteria for optimization of the Brazilian electricity system, including the Itaipu reservoir and the national interlinked system. Regional interchange of energy in any time period is calculated on the basis of regional differences in marginal costs of operation calculated using the level of storage in each subsystem, i.e., some value is placed on the level of water in each dam, though only on the basis of increasing marginal costs of operation as the level of water declines. The economic value of water is the average of the product of marginal costs as defined above and the actual generation of electricity for each month in a year. The cost of electricity and thus rates to be charged follow from this.

The model described above helps in planning for long term capacity, with reasonable demand assumptions. It accounts for the stochastic nature of water inflows in the dam and thus predicts required capacity with a predicted probability of shortage. It also includes a rational mechanism for dispatching generators.

3.1 Marginal Water Value

What the model currently in use does not do is adequately place a value on water, which, in a system of any given size and inflow characteristics, is a limited resource. Two major constraints that define generation from any dam are the storage capacity of the dam and power generation capacity. The first deals with an energy constraint, the second with a power constraint. Thermal systems on the other hand have only the power constraint; the energy

[21] Metodologia e Criterios para Elaboracao do Plano de Operacao para 1996, SCEN/GTMC - 01/95, December 1995.

constraint fades away with an almost unlimited supply of fuel even over a short period of a few days.

This unique characteristic of water (potential) energy should lead us to put a value on it so long as it is limited. The amount of energy available depends upon a number of natural factors, which may be broadly defined as inflow characteristics and fixed capital in the plants, i.e. size and storage characteristics of the reservoir. To tap a larger amount of water one would have to invest a larger amount of fixed capital. Greater the fixed capital, more the water that is available. Water in that case is a less scarce resource. Fixed capital, in this sense, is a part of the system and a carefully designed system should be able to recover those costs, by putting just enough fixed capital that can be recovered.

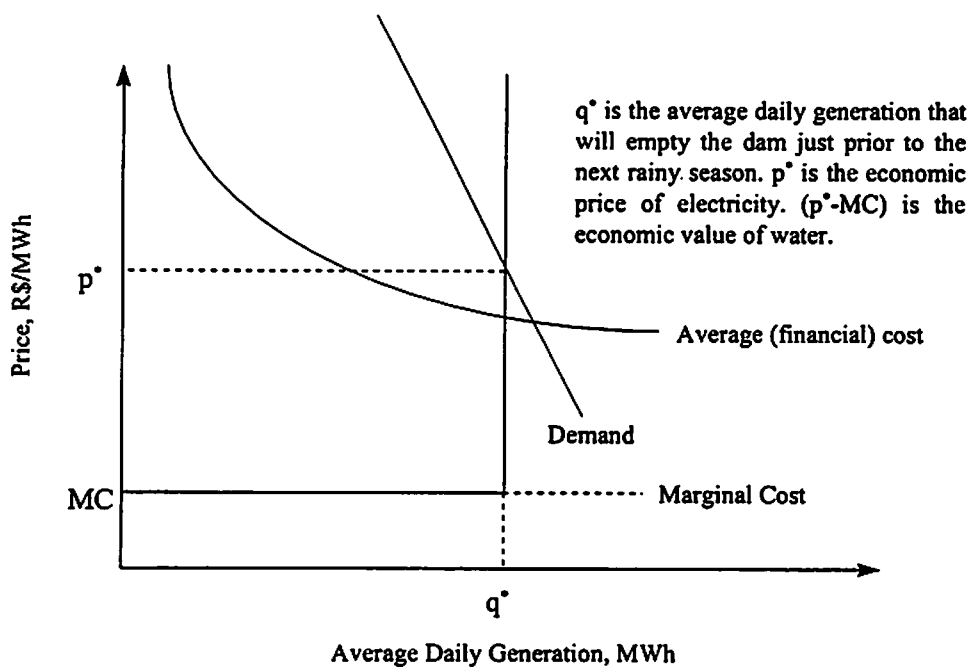

Figure 4: Economic Value of Water

To better understand the marginal value of water, take the simple case of an isolated subsystem[22] along Rio Parana with only one dam. Assume also that transmission links to other systems are prohibitively expensive. Demand exists within the geographical area of the subsystem and the dam is designed to meet the demand. During a rainy season, if the dam overflows the marginal cost of generation is only the cost of operating the turbines in the dam and the regular operating overheads associated with it. The marginal value of water here, as the dam overflows, is zero, i.e., having more water would not provide any additional benefits at this stage. At the end of the rainy season, if we expect no further rainfall, the water remaining in the dam should supply electricity for the rest of the year. The price at which all of the water will be exhausted is defined by the demand function and the difference between this price and the marginal cost of generation is the value of each unit of water stored in the dam.

In case there is more generation in the current period (due to a higher demand) than what we had expected when we first calculated the price, we would be left with less water in subsequent periods to supply energy for the rest of the year. In that case the value of each unit of water stored in the dam would increase. On Figure 4 this is the same as the demand curve shifting outwards in the current period, and thus q^* in later periods would be lower and p^* higher. The marginal value of water would be the value of using an extra unit of water in the current period as compared to storing it for the next period. What is clear is that if we do account for the value of water, the price of electricity would be determined by the marginal value of using water rather than storing it for later periods.

The question now is – will a competitive market, where each firm has similar objectives of profit maximization, account for the economic value of water. Think of a simple situation in which there are an unspecified number of firms in the market. Each of them would like to sell as much electricity as possible during periods when price was highest. If the dams drained out such that there was only one dam left with some water, that dam would be able to sell electricity at

[22] A subsystem, by definition is a subset of a larger integrated system with generating stations and/or consumption. The subsystem is linked to other subsystems through transmission lines with limited capacity such that interchange of electricity is limited. A clear definition of the geographical area of a subsystem is hard to obtain without considering congestion in transmission links that may isolate the subsystem. In case the price in each of the subsystems is different there would be a demand for transmission from the less expensive market to the more expensive market. The market will operate in such a way that the congestion price of transmission will be the difference in prices in the two markets.

very high prices. Naturally all dams would like to store water for an event like that. Thus, all of them end up draining their water at a rate where the current price is the same as the expected future price.

If all estimates for demand and supply, i.e., total energy demanded each period and total water inflows into the dam are accurate and deterministic we would observe the price for energy to remain constant for the period after the rainy season, and to be lower (even up to the marginal cost) during the rainy season if there was a chance of spilling water.

Several considerations should be kept in mind. On the other hand, a dam with a surplus of water would either have to drive prices down till demand and supply became equal[23] or deliberately spill water. In some cases, the price may decrease to just the variable costs of operating the generators in the dam, in which case the marginal value of water would be zero.

[23] The dam will be able to generate as much electricity as its installed capacity permits. The constraint of power capacity has been ignored in this analysis, since it becomes relevant only in some isolated cases. One specific example may be during the rainy season. At prices equal to marginal costs, the market may demand more electricity than installed capacity. In that case dams will continue to spill water, and prices will remain higher than marginal costs even though the economic value of water is zero. In such cases the market places an economic value on the addition of a turbine, without adding extra storage capacity.

While designing a

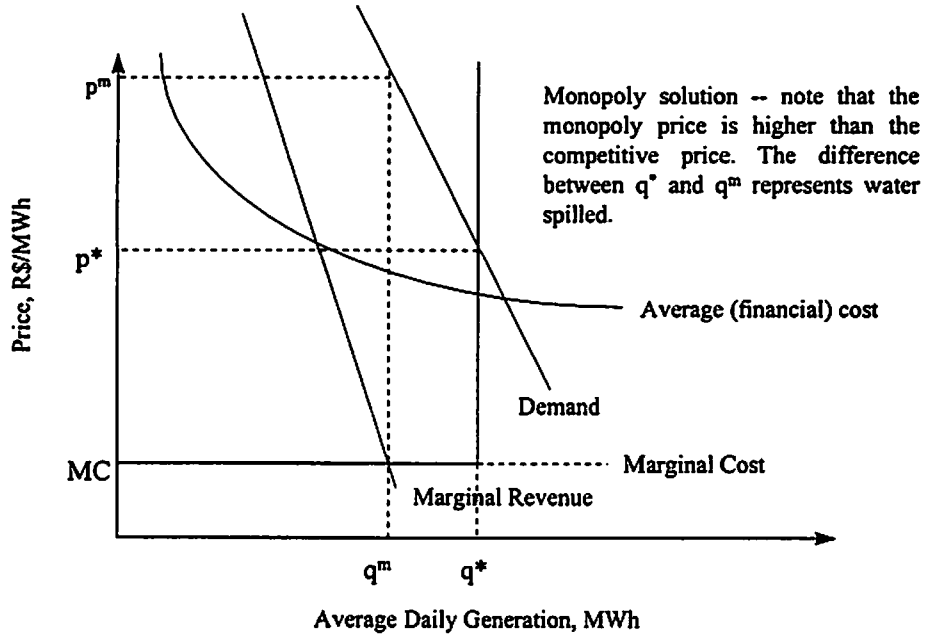

Figure 5: Monopoly Solution

market, these factors will have to be taken into account. Most dams will probably spill some water during the year. Deliberate spilling, on the other hand, is cause for concern since, with an inelastic demand, market power would lead a profit maximizing firm to set prices higher than what is efficient and then deliberately spill water.

For an efficient market to operate prices must be equal to the sum of marginal costs of operation and the marginal value for water. Also, the marginal value of water applies, in increasing segments, to all the water in the dam. Deliberate spills of water represent real economic (resource) cost and are avoidable.[24]

[24] In the monopoly case, the firm has the ability to set prices. Since demand is inelastic, reducing supply by one percent will increase prices by more than one percent, thus leading to higher profits overall. The generator will continue to do that till reducing supply yields no further profits. Since the dam has more water than will be used to supply market demand, it is inevitable that the dam will have to spill some water.

One must be careful though of the assumptions above. Both demand and supply (inflow of water) are stochastic in nature. It may be possible to project demand in the near future and, in the very short run (one day to one week) it may indeed be inelastic and exogenous to price-supply-demand relationships. However, demand is not so inelastic even in the medium term (months) and may be endogenously determined with supply and thus prices. Demand may also change in the short run, though estimates of average demand should be reliable to within a few percentage of actual demand. Supply, on the other hand is a harder case. Rainfall is extremely stochastic in nature and exhibits high variances over both the short run as well as the long run. Changes in either demand or supply will lead to changes in the marginal value of water and thus in prices.

What does all of this mean for Brazil. In short, the current system of optimization does not account for the fact that water is a scarce resource. The current system does account for the fact that there are (financial) costs to harnessing hydropower, though it falls short of including the fact that prices should include the economic cost of generation, not just the financial cost. The cheapest water resources have been used first and capital costs on the dams built to harness them are recovered through current rates. Current rates however do not account for the replacement cost, or the long run marginal cost of electricity. Economic costs should include the value of scarce natural resources, which will not be available as Brazil expands its generation capacity. If prices remain below the replacement cost of electricity the incentive to build new dams is non-existent, thus making government intervention through subsidies necessary.

Taking into account the marginal value of water should give an idea of the optimal size of the hydroelectric system. Clearly, the optimal size of the system is one where the average financial cost is equal to the sum of the marginal cost and the economic value of water.[25] Note that with more investment in storage facilities, the economic value of water decreases.[26] Thus there ought to be some point at which the average fixed costs are equal to the economic value of water. In the case of Brazil, the economic value of water is clearly above the average fixed cost

[25] If the average financial cost of the system is greater than replacement cost for electricity there would be an incentive to install additional capacity, thus reducing the economic value of water. This may lead the dam to become a "stranded asset".

[26] It can be shown that there is an optimum size of a dam on a river as well as an optimum number of dams along the river.

of establishing new facilities.[27] Moving to a market which accounts for the economic value of water will give better signals to determine investment decisions. Thus, investment decisions, which are now made on the basis of a five percent probability of shortage will be governed purely by the economics of the system. The biggest advantage here is that investors will make decisions based upon market information, rather than government initiatives, and thus be responsible for their investments.[28]

3.2 Designing a Market for Generation

With the assumptions laid out in the section above, let us analyze the behavior of a profit maximizing firm in a market, where water has an economic value due to scarcity on account of limited storage capacity, generation capacity is limited to installed capacity and demand and supply are known in advance. The firm has no market power, i.e., the price observed in the market is independent of the firm's production. These conditions would be required to establish an efficient market and can be achieved by dividing generating assets in each subsystem in such a way that monopolies are not created.

The problem for this firm is to decide whether to generate or not in the current period, given a particular price in the market. The firm has access to publicly available information about prices and the level of storage in each dam. The firm's generation decision has to be based upon current and expected future prices.[29] If it expects prices to rise in the future it will hold back its water and generate at a later date to achieve greater profits. However, the same would be true of all firms, since they observe and sell at a common price. Thus, the market establishes a

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[27] This statement is based upon a simple analysis of financial costs of dams under construction. It ignores costs associated with overcoming environmental opposition. There may also be a total capacity constraint due to environmental reasons, in which case the fixed cost of new facilities is infinite.

[28] Compare this with systems where the government gives out contracts to set up power plants. Contracts tend to get more complicated due to agency problems in those cases. All of those problems are avoided here if the only determining factor for new investment is the economics of the market.

[29] Each firm in the market will need to have access to information regarding the storage levels and characteristics of other dams. The hydroelectric energy system has an overall limited energy constraint, which determines prices. It would be necessary for each generator to know what the constraint actually is. For example, in Figure 4, we showed that there is a price at which the expected demand and supply equilibrate in such a way that expected prices remain constant for the rest of the year. Demand expectations will be developed out of market studies and less likely to be privileged information. However, expected supply is a function of the level of storage and expected inflows in each dam. This information would have to be available to all generators in order to estimate expected supply.

common marginal value for water.[30] The price a generator will bid should be such that there is no expected change in its own offer price in subsequent periods.

Going back to the discussion in the previous section, the price observed on the market would be constant if rainfall and demand do not deviate from expected values during this period and there was no risk of spillage. Prices would be constant even across rainfall periods, even over many years if inflow was known in advance and there was no spillage. Again, the only factor that would change prices on the market would be unexpected demand or supply, very likely given their stochastic nature.

Another factor that may lead to an increase in price over time is risk aversion on the part of the firms. Their operating profits, which go to pay their fixed costs are a product of the prices. While there is certainty about prices in the current period, the distribution of prices becomes wider looking out further in the future, again due to the stochastic nature of supply and demand. This may lead firms to sell at a slightly lower price in the current period than in later periods, thus demonstrating a high discount rate due to risk, consistent with economic theory. The exact behavior of the firm will be hard to determine by theory alone. It is likely that indications of risk aversion will not be available till firms are actually privatized or till a market is really under operation. What is clear, though, is that prices will be lower during a period of certainty, such as during a rainy season when rainfall is more predictable, than during periods of uncertainty, such as before the rainy season when it is more difficult to predict rainfall. Also, since in the rainy season prices are lower, expected prices will continue to rise through the year till the next rainy season.

To make the market work in Brazil, the government will have to make some provisions for prices to be quoted continuously. This is no different from established financial markets. In fact, this section gives an idea of the necessity of the market operator and what information will be required from it. If firms are expected to compete in the market they need to have access to enough information to ensure efficient operation.

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[30] Common value for water does not mean an equal value for water. The value for each cubic meter of water will be different in different systems if there are transmission constraints or greater deviations from expected values of demand and supply. See section 3.9

3.3 Establishing the Expected Price on the Market

The foregoing analysis shows the feasibility of a competitive market for generation and concludes that there is an expected price on the market, corresponding to the marginal value of water. We also know that the lower bound for the expected price is the marginal cost of operation, where the marginal value of water is zero. What we do not yet know is the upper bound for prices.

In a time period of say one year, where energy supply is constrained by the amount of water in dams, prices can rise to any level such that demand and supply can be equated. However, if prices rise above the replacement cost for plants, i.e., long run marginal costs, the market provides incentives to set up a new plant. Since we have already established that prices should remain relatively stable during the course of the year after the rainy season, we can expect the new plant to have an opportunity to pay off its fixed costs. If the new plant is hydroelectric, it gets integrated into the system, just as any of the other plants, there is no reason to expect a change in market operation from what we have observed. Environmental constraints on setting up new storage capacity will make it unlikely that marginal capacity addition will be from hydroelectric plants. That leaves us with the choice of gas based plants, where the long run marginal costs are of the order of R$50 per MWh.[31] This should be the expected price on the market.

Note that this price is actually much higher than current prices for generation, which are in the range of R$32/MWh. This sudden increase in prices may be difficult to pass through to consumers. However, for the electricity system to work without much government intervention this is the economically efficient price. Methods to smoothen the trend of price increase are discussed in section 3.5. Note also that prices within a year may be more than expected due to a short term supply constraint, in which case government intervention may be necessary. Efficient contracting could be used to stabilize prices, as discussed in section 3.10.

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[31] One may dispute the cost of gas generation since recent constructions such as AES's Uruguayana plant, claim a sale price of R$34/MWh. How much power will be available from such cheap sources is questionable. There is a great deal of optimism about the Bolivia-Brazil gas pipeline, which is expected to bring in gas at R$27/million Btu to Sao Paulo. However, the pipeline is yet to be constructed.

Before moving on to other topics, it is interesting to observe that a competitive market dominated by hydroelectric generation, where the costs of switching on and off are small, is very liquid in the short term. Unless supply is constrained by generation capacity, prices are not likely to vary between half hour periods, as they do in other markets, such as the United Kingdom. This is because the marginal cost of operating plants does not fluctuate much. The major component of cost, the economic value of water should not change, if the peak and off-peak loads are accounted for. One would expect prices to remain stable during a day, though there may be variations between days, depending upon the stochastic nature of inflow and demand.[32]

3.4 Implications for Asset Valuation

One important corollary of the debate above is that existing hydroelectric generating assets are currently priced at below their economic value. The value of assets used to calculate an average cost of R$32 per MWh comes from their book value, net of depreciation of existing assets. Debt incurred for the construction of these plants has been paid (in part) and thus the government treats it as an asset that has been paid up (in part). However, the economic depreciation of the asset is much less than the financial depreciation that has been charged. Effective economic depreciation should take into account loss of productive life of an asset and changes in technology that make existing assets more expensive than new assets.[33] Generally for most production processes the cost per unit declines over time with growth in capital productivity. However, in a situation where long run marginal costs are increasing over time, as is the case with electricity in Brazil, economic depreciation is less than loss of productive life and in fact negative.[34]

The primary reason that we observe negative depreciation is that water values were never defined. Starting with an initial allocation of property rights over water, a scarce resource,

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[32] The analysis in this section draws from T. J. Scott and E. G. Read, Modelling Hydro Reservoir Operation in a Deregulated Electricity Market, Energy Modelling Research Group Working Paper, University of Canterbury, New Zealand, 1995.

[33] For example, if the cost of generating electricity in 1997 was R$32/MWh and in 1998, due to the availability of new technology, the cost went down to R$30/MWh, economic depreciation of the existing asset would be equal to 2/32 or 6.25 percent. Tax laws that permit rates of depreciation different than this may cause distortions.

could have led to the more common result of constant or declining long run marginal costs over time. However, it is understandable that this was hard to do many years ago when water was a more plentiful resource.

Asset valuation or revaluation should be done on the basis of its expected returns over operating costs. As we have already established this value is the value of water that a dam stores. This would lead to an asset value equal to

$$Asset\ Value = water\ value \times quantity\ of\ water\text{, or}$$

$$Asset\ Value = (expected\ price - operating\ cost) \times quantity\ of\ water$$

Asset values will be required at the time of privatization of generation. However, a market may not be operational at the time. The process of privatization, especially auction design will depend heavily upon the order in which privatization and restructuring are taken up. While this document does not analyze the privatization process itself, there is scope to do that within the framework established here. A market value will be established during the auction process for each dam that is sold. This market value, instead of the historical value, should become the basis for all future accounting.[35]

3.5 Integrating Thermal Plants in the System

Addition of thermal plants to the system presents both a challenge and an opportunity. The challenge is to make recovery of fixed costs compatible with the prices prevailing on the market. Clearly, if prices are at or above the long run marginal costs, recovery of fixed costs for new plants should not be a problem. However, we already know that there is a chance of prices being below long run marginal costs for at least a part of the year, when dams are expected to spill water. Profitability of thermal plants during this period would depend upon the nature of

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[34] Managerial decisions change in a regime where the long run marginal costs are increasing over time. See Robert A. Leone and John R. Meyer, Capacity Strategies for the 1980s, Harvard Business Review, November-December 1980.

[35] Brazilian law prohibits the sale of any public assets at less than their book value. Though this seemingly innocuous provision of the law was aimed at protecting public assets from being sold cheaply it severely constrains the privatization process. For example, CESP's Porto Primavera project has a book

contracts for their power. For example if a thermal plant had a firm contract for delivery of a fixed quantity of electricity throughout the year, it would be profitable for the firm to shut down operations and buy electricity from short term markets if the market price was less than their marginal costs of operation. This is likely to be the case if dams were spilling water, because the avoidable costs for a thermal plant would be in the range of R$20-25/MWh, i.e., the cost of fossil fuel, while prices on the market may be as low as R$5-7/MWH, i.e., the marginal cost of hydroelectric generation.

By making a profit on firm contracts the thermal plant can indeed offset its fixed costs. However, if this is the case the price on firm contracts is also likely to be less than the long run marginal costs. What will actually happen in a market is hard to determine, though it is quite clear that if prices were allowed to rise to any level, there would be a price at which new thermal plants would be assured of paying off their fixed costs.

One option might be to load an obligation upon some or all hydroelectric generators to build thermal capacity. With excess capacity, prices on the market would not rise to long run marginal costs. In due course, as the slack in the system disappears, prices would rise to long run marginal costs. Delaying or slowing down the growth in prices of electricity may be desirable for political reasons, as well as to avoid inflation in the economy. However, building slack is not desirable from an economic perspective since it causes unnecessary distortions by providing a subsidy on new capacity additions and defeats the very purpose of a competitive market. Besides, the privatization process may get seriously jeopardized if dam owners (concessionaires) were unable to make a profit for several years.

If hydroelectric generating stations were loaded with an obligation to build thermal capacity that is unprofitable for at least a few years, asset values for the hydroelectric stations would be discounted for the expected losses on thermal capacity, thus reducing proceeds from privatization. Properly designating obligations to build thermal plants in privatization contracts should help in achieving the goal of slowly increasing prices. One must keep in mind though that deliberately manipulating prices by these means is inefficient. Artificially lowering prices is also

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value which would lead to prices in excess of R$110/MWh upon completion next year. Naturally the market value of this plant is much less than its book value.

undesirable since sustaining that price would require either subsidies for new capacity or resorting to load shedding.

3.6 Implications for Social Policy

Our discussion so far has focused upon establishing a value for water and thus a price for electricity. This discussion has assumed that the only use for water is for generation of electricity. Alternative uses of water such as irrigation and flood control have been ignored. That does not mean that alternative uses of water are not compatible with the model proposed. Flood control and irrigation do have an economic value and storage or discharge of water for these purposes can be made compatible with competitive markets.

Flood control is a public good. Irrigation has a public purpose but is not a public good since the benefits from irrigation are clearly directed towards a group of people, namely farmers. The government can make flood control and irrigation compatible with the market in two ways. First it could buy water at the marginal water value. By doing so the government buys the right to either have the water discharged at an appropriate time or have it stored till such time as discharge becomes safe and in the public interest. Further consideration needs to be made of the exact mechanism for achieving these social goals, though it is reasonable to assume that they are not incompatible with the market. The other method for achieving objectives of flood control and irrigation is by properly allocating property rights for water, which is discussed further in section 3.8.

The other aspect of social policy is high prices in the short run. As pointed out above, prices can go up beyond long run marginal costs between two rainy seasons, though prices should converge to long run marginal costs over a number of years. This would have a differential impact based upon income, and may be undesirable from a social perspective. Excessively high prices may also shut out access for some very poor people. In some cases it may be more equitable or fair to cap prices and resort to demand reduction through load shedding as it is done now. There are significant social advantages of load shedding which may overshadow economic inefficiencies in many cases. A reasonable cap for prices in this case would be one that is 20-25 percent above long run marginal costs, since that still provides strong incentives for capacity addition.

3.7 Controlling Market Power

Probably the most significant role for the government will be in controlling market power. The concern with market power is the following. If a firm has a large enough portfolio of generation assets in order to be able to become a price maker, it may resort to deliberate spills of water which would increase the marginal value of water and thus prices on the market.[36] Since demand is relatively inelastic this may prove to be the best strategy for the profit maximizing firm with market power. This is analogous to a monopoly problem. The firm may also set prices lower than the sum of marginal costs and marginal value of water, thus depleting water resources faster and leading to higher prices later. This is analogous to predatory pricing.

Monitoring predatory pricing or monopoly behavior may prove to be challenging. Brazil does not have a history of monopoly regulation, which compounds the problem. The analysis required for this is much larger in scope than this study and thus not taken up here. Some guidelines can be given though.

Monopoly problems can be eliminated by careful division of generating assets such that there is no dominant firm in any subsystem. For example, the regions now served by each of the major generating utilities are very likely to be isolated subsystems. Privatizing each of these utilities as they are, i.e., giving a firm the right to control Electronorte or any of the other utilities, will result in the creation of a monopoly. Subsystems may need to be rearranged to suit goals of monopoly regulation. In some systems, with very few generating assets, the presence of a monopoly may be inevitable, till enough transmission links are available to other systems.[37]

Release of water for an uneconomic use or deliberate spillage are indications of manipulative strategy. Some method to determine the occurrence of such an event will be helpful in monopoly or anti-competitive regulation.

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[36] For the firm to have the ability to set prices, it should own a large percentage of the generation capacity in a subsystem that is likely to get isolated due to transmission constraints. Note that if the firm spills water, there may be dams downstream that will hold the water instead, possibly limiting the monopoly firm's ability to set prices. However, the operating constraint is one of transmission.

[37] Note that if enough transmission links are available the subsystem really gets integrated with adjoining subsystems, to form a larger subsystem with more generating assets.

3.8 Establishing Property Rights for Water

Previous sections have established a potential source of conflict. Property rights over water need to be very clearly defined in order to avoid confusion and uncertainty in the market. Several alternative definitions are possible, though the feasibility of each one of them within Brazilian law needs to be checked.

One possible definition is that all the water in the dam belongs to the firm that owns (a concession for) the dam, which is then free to use it as it wishes, within a set of anti-monopoly regulations. The potential problem with this definition is in reconciling social objectives of flood control and irrigation. One can foresee a case where a dam may be unwilling to release or store an incremental quantity of water, even if it is paid to do so by the government. Such problems may be covered by anti-competition regulations, though they still remain a potential source of conflict.

Another definition of property rights would give the firm rights to all the water in the dam, apart from either a fixed percentage or fixed quantity of water. The government has a lien on this portion for use in a socially justifiable cause, even though that may be incompatible with economic prices of water on the market.

Definition of property rights will have to wait for further research into the nature of the competitive market. However, clear property rights are essential for the successful operation of a competitive market and cannot be brushed aside.

3.9 Network Externalities

Two types of network externalities complicate the analysis that we have developed so far. One relates to bypass of water between dams through channels. While this is unlikely it is worth considering. The other externality relates to congestion of transmission lines.

Take the case of an isolated system with two identical, adjoining dams and a common market. If transmission costs between them and a given market are the same there is an equal marginal value of water and thus an equal price for electricity that each dam sells. If, on the other hand, the cost of transmission between each of the dams and the market is different then the marginal value of water in each of those dams is different. Transmission constraints may make it

impossible for the cheaper dam to provide enough energy for the market, in which case there is an economic cost of congestion of transmission lines.

The same analogy holds for subsystems since interchange capacity between subsystems is limited. Due to this, different markets (subsystems) will observe different prices. The advantage of a competitive market is that prices on the market will indicate the need for additional transmission lines. This eliminates even the need for central planning of transmission, thus allowing for the formation of a separate system of transmission providers. Regulating the transmission provider becomes easy because the market provides indications of transmission requirements and thus prudence of investments in transmission assets.

In addition to this, what this discussion about transmission capacity tells us is that each of the dams in the system will empty roughly at the same rate and not in some order of proximity to the market. Consider the following – there are two dams with an installed generation capacity of 500 MW each supplying electricity to a market, which consumes 500 MW at any time. The storage in the two dams together is just sufficient to supply the market through the year. One dam is farther away from the market than the other. At first glance, one would think that the dam closer to the market should empty out first, since variable (and even total) transmission costs are lower. However, after this dam was empty we would need a 500 MW transmission all the way from the distant dam to avoid congestion. The fixed cost of this transmission link is totally avoidable if both the dams produce 250 MW each through the year. The important conclusion from this discussion is that no dam will sit idle for a prolonged period – something which private investors will look for in assuring themselves of a steady cash flow.

In creating a wholesale market, one of the cost factors that will need to be properly accounted for is transmission costs. Not incorporating transmission costs is likely to result in inefficiencies and wasteful use of water. In the special case of hydroelectric, there is a near equivalence between water flows along river networks and electricity flows on transmission networks. Optimizing and pricing only the water flows and not the electricity flows results in the optimization of a subset of the entire electricity system, which is not desirable.

3.10 Efficient Contracting for Privatization

The big question now is what kind of privatization contracts the government should offer. In principle, the best form of privatization would be to sell off the generating plants, including assets and all forms of residual ownership rights.[38] There are two major advantages of this kind of a privatization over concessions for a fixed period. First, the operator of the dam has every incentive to maintain the generating plant and make investments that maximize the value of the dam over the useful life of the dam. Second, the operator is also responsible for all forms of residual claims on the dam, including any environmental damage that may not be recognized for a long time. The major disadvantage is that the private investor will have to invest a sufficient amount of capital upfront to acquire the stock of the company. With a large scale privatization, the market may not be liquid enough to absorb the sale of stock, unless the proceeds from the sale of stock are realized in some form of installment payment. The other disadvantage may be that there is a reasonable amount of uncertainty about the operation of the market and thus the profitability of the dams, leading to a high discount rate for future profits and thus a low stock value. The government is naturally better placed, as the current owner of these assets, to manage that uncertainty.

The more common form of privatization in Brazil – granting of concessions for a fixed period of time has other advantages and disadvantages.[39] The major disadvantage is that the private firm does not always have the right to do what it wants with the assets and thus private enterprise, one of the major reasons for privatization, is not exploited fully. In addition to this, the private firm has little incentive to invest in improvements that bring benefits after the end of

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[38] A privatization of this kind would generally entail the corporatization of each separate parcel of generating assets being privatized, and the subsequent sale of stock. The government retains no residual ownership rights and has no lien on the profits of the privatized firm, except for income taxes, which are applied on all firms.

[39] The Brazilian Constitution of 1988 restricts the scope of privatization. Consequently the only form of privatization undertaken is the granting of concessions for existing assets. Concession law has developed and become sophisticated as a result. Though very little new infrastructure has been constructed by the private sector it is commonly believed that BOT contracts will become popular in due course.

the concession period. In some cases, concessions may also end up restricting additions or enhancements to the asset with the passage of time.[40]

Concessions, despite all of these shortcomings, have one major advantage, which the government can exploit to keep the price of electricity in check. Think of what would happen to prices in a particularly bad rainfall year. Prices are likely to increase sharply, especially since short term demand for electricity is relatively inelastic. Since demand is relatively inelastic, profits will increase in a bad rainfall year. Similarly in a good rainfall year prices will decline sharply, and thus profits will be lower. If the government charges a constant concession fee each year, the concessionaire is exposed to weather related risk. Moreover, the incentive to the firm is always to maximize profits, in which case it will try hard not to let prices drop in a good rainfall year by spilling water.

The alternative for the firm is to enter into a long term (multi-year) supply contract, at an assured price. This will ensure a steady cash flow to the firm to pay off the concession fee. If all of the firm's generation is under long term contracts, the firm will have a constant cash flow over years. However, the firm cannot enter into a contract for all of its generation, since it does not know its generation potential for any year in advance. What it can reasonably do is enter into a long term contract for a large proportion of its average generation, such that even in a bad rainfall year it has the capability of meeting its contracted supply. By contracting for a large amount of energy, the firm has an incentive to hold down prices if it is unable to meet its contractual obligations through its own generation.[41]

For example, take the case of a firm that sells 70 percent of its average generation through long term contracts. If the inflow into the firm's reservoirs in any one year is less than 70 percent of the average, the firm will have to buy electricity from short term markets, such as a

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[40] A case in point here is the Nova Dutra highway, linking Sao Paulo and Rio de Janeiro. The Dutra highway is the only major link between the south and the northeast of Brazil. Due to the auction process the concession got bid down to an operation and maintenance contract with little provision for addition of lanes or parallel roads in due course. If in the future, there is congestion on the road the government may have to either force the current concessionaires to build more lanes or a parallel road, or revise tariffs on the Dutra highway to help subsidize the construction of a new road.

[41] This discussion draws upon the restructuring experience in New Zealand. For a detailed discussion of contract pricing and hydro-thermal coordination see T. J. Scott and E. G. Read, Modelling Hydro

spot market, to fulfill its contractual obligations. In such a case the firm will have a strong incentive to economize on energy use and give incentives to its consumers for a reduction in demand. Thus, demand is likely to be reduced with the overall effect of moderating prices. The key, however, is that prices do remain under reasonable control.

The question then is – what would induce firms to commit a large part of their generation to long term contracts. Clearly, if firms were risk averse they would tend to put at least some of their generation under long term contracts irrespective of what the expected spot price would be in the future.[42] This kind of risk aversion can come out of some kind of fixed concession payment, due each year (or each quarter), which the firm will try to cover through long term contracts.

The most efficient privatization contract in this case may be a two part tariff, in which the firms pay a fixed concession fee each period, as well as a percentage of their revenues, net of concession fees. This will induce firms to engage in long term contracts, as well as provide a disincentive for charging excessive prices since they will have to give up a proportional share of their profits to the government.[43]

Clearly, if the price of electricity in the competitive market is closer to R$50 per MWh the government will collect substantial rents from the sale of hydroelectric assets. This should be seen as an advantage since the government can then use that money for other purposes, including redistribution of wealth, paying off debt or to reduce taxes. The fact that higher electricity prices also reduce distortion in the market and provide correct incentives for investment is an added bonus.

Reservoir Operation in Deregulated Electricity Market, Energy Modelling Research Group Working Paper, University of Canterbury, New Zealand, 1995.

[42] For a general discussion of the economics of forward contracting in the early phases of United Kingdom's restructuring see Andrew Powell, Trading Forward in an Imperfect Market: The Case of Electricity in Britain, The Economic Journal, 103, March 1993, pp. 444-453.

[43] The analysis of concessions is done with the assumption that an outright stock sale is not possible. One would have to give serious consideration to a stock sale since it has significant benefits.

Section IV: Recommendations

It is clear that the government of Brazil is making a laudable effort to infuse private capital into the electric utilities sector. At the same time there is room for caution when undertaking a venture as ambitious as this. The alternative models of industry structure outlined in Section II permit different forms of privatization, though the competitive market goes much farther in making privatization, and the operation of a private market effective. What it also does is prove that privatization without competition is an incomplete solution and, in the absence of adequate regulation, a recipe for disaster. The government should be cautious of advice on the ease of creating a regulatory agency. It must realize that countries that have some experience with independent regulation have taken decades to develop a regulatory system that is only half as good as a competitive market, and are now in the process of moving to a competitive market themselves.

This paper lays out the basic ideas behind a well designed competitive market. Much needs to be done before the government finally establishes a competitive market. However, a competitive market for electricity generation holds immense promise for Brazil. Despite the problems associated with a predominantly hydroelectric system, the competitive market should meet all requirements for efficiency. In fact a competitive market, if set up correctly, would function so well that it is unreasonable not to have one.

A well designed competitive market would be capable of regulating efficient production and controlling prices within reasonable limits, factoring in considerations of social policy as well as efficiency of water use. It will provide signals for long term investments in both generation and transmission and effectively incorporate thermal generation as and when it becomes available.

The government and the people of Brazil must also realize that the rationale for moving to a competitive market goes beyond economic theory. Using taxes to pay for new generation is inefficient and also distorting. Besides there is no reason why people who use electricity should not pay for capacity addition as well. In cases where some underprivileged sectors need to helped, the competitive market still retains the possibility of explicit subsidies.

The greatest opportunity for Brazil lies in the fact that all generating assets are now owned by the government. Thus, windfall profits from establishing a competitive market can easily accrue to the government and thus the people of Brazil. If, instead, the government chooses to privatize without introducing competition, at some later date it will have to reorganize the industry, as has been the experience in other countries. Windfall profits at that stage will be collected not by the government, but by private owners of the generating assets. While the strategy of privatizing without competition may help in increasing the proceeds of privatization in the short run the government can also increase the sale value of the generating plants by correctly pricing electricity. For all of these reasons it is essential that the government really get privatization right.

To establish a competitive market the first requirement would be to give up price controls. The essence of the competitive market that we have developed so far is one in which price is determined by the market. The foregoing analysis suggests that the market will establish a price that is economically efficient. Since that is the case there is no need for a central regulatory authority setting prices.

a. In order to make the market work, the government should give out contracts for operation of the generating stations, as discussed in section 3.10. These contracts should be issued out for dams in such a way that there is no monopoly problem in any subsystem. From section 3.7 we know that the presence of a monopoly in any subsystem can lead to an inefficient economic outcome. While it may be possible for a competent regulatory authority to oversee the operations of a monopoly, it is much better to avoid the creation of a monopoly at all. Specifically, from the definition of a subsystem, we know that transmission links are critical to the isolation of a subsystem. This understanding may help in avoiding monopoly power. Closer analysis of the generating system and transmission network, with existing data should give a good idea of which subsystems are likely to get isolated easily and thus need special attention.

   Competition in generation can be set up with freedom for generators to operate, without interference from regulatory authorities. The only form of regulation should be to control

monopoly power and to fulfill certain pre-defined social policy objectives as outlined in section 3.6.

b. Generators will need to have access to a market information, including prices and storage levels in other dams. This would necessitate the creation of an exchange where data can be exchanged, updated for variables such as inflow, generation, volume of trades, etc. A market operator, with sufficient authority for independent operation, should be in charge of this function. Recent advances in Sao Paulo in establishing a futures market for commodities should help in this exercise.

c. The government will also need to set up a transmission system operator with transparent rules for access to transmission lines. Transmission costs will have to be established on the basis of known principles of economics and made known to all traders on the market. One method of making the market really efficient would be to quote transmission costs along with spot market prices. Transmission prices are implicitly assumed when calculating the locational spot price for electricity. The transmission system operator will need to be independent of influences from both generators and consumers.

d. Property rights for water need to be clearly defined, in keeping with the needs for economic efficiency and obligations towards social policy. There is an easy way to incorporate social considerations into the competitive market – defining property rights correctly, and a much harder way – constantly regulating the activities of each firm in the market.

Much needs to be done also about other segments of the industry, which are not discussed in this paper. The role of the system operator and market operator are, each, as important as the nature of competition in generation. Whether to move to a pool based system will become an important consideration while designing a reliable transmission system. On distribution, the government will have to decide what level of competition it wants – whether to restrict competition to wholesale wheeling or go all out to retail wheeling.

Each of the above factors will influence the operation of the competitive market for generation, though the basic principles are robust to withstand a wide variety of options in

transmission and distribution. It cannot be emphasized enough that there is a need to do something creative in the privatization process.

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