The George Washington University

WASHINGTON DC

IBI – INSTITUTE OF BRAZILIAN BUSINESS AND PUBLIC MANAGEMENT ISSUES

Theory and Operation of a Modern National Economy

PROBABLE BASICS TRENDS OF THE WHOLESALE ENERGY MARKET IN BRAZIL

Final Paper
Spring 2000

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SUMMARY

Presentation

Nowadays one of the main issues of the Brazilian Electricity Industry restructuring is establish the Brazilian Wholesale Energy Market (MAE)[1] one pillar of the new model. The main objective of this paper is to present probable basics trends of the MAE in the near future.

The first part of this paper describes the key issues of the Brazilian Electricity Industry restructuring that have already been defined. The second part will describe the market principle applied to electricity. The third part will present an overview of the International Experience in Wholesale Electricity Market. The forth and fifth parts will discuss the main aspects of Brazilian Energy Wholesale Market.

Finally the sixth part present the Government role in the new electricity industry and the last, but not least, reach the conclusion.

Key words – Electricity Energy - Industrial Restructuring – Wholesale Energy Market.

[1] MAE is Mercado Atacadista de Energia that is the name of the Brazilian Wholesale Energy Market

1 Introduction

From the early discussions on the reform of the State emerged the vision that it should leave of the productive activities. Besides social issues, the State should concentrate efforts and resources in its role as business regulator and as formulator of economic polices.

This vision led many countries to review the institutional model applied to the electric energy industry, mainly based on state monopolies. It was introduced legislation in order to bring private capital, competition in generation and freedom of choice by consumer to the electric energy industry.

Such institutional reforms were accompanied by technological development, which promoted cost reductions, specially the ones associated with the electricity generation by modern thermal power plants. The entrance in the market of those units, that can be assembled in small periods, have allowed the participation of private economic agent in the generation of electricity (Hunt & Shuttleworth, 1996).

As recognized by Rudnick (1996), the basic economic characteristics of the value chain in the electric energy industry were affected by technological change with different implications for the generation, transmission and distribution. The generation is an important part of the value chain, in which there are not any significant entrance barriers related to economy of scale. Therefore, competition can be introduced. On the other hand, in transmission, economy of scale is vital and tends to produce a natural monopoly. For this reason transmission should be regulated to prevent elevation in prices for its service.

In addition, distribution has important economies associated with density of supplied load. Therefore, geographical concessions for distribution companies have been attributed to regulated agents. The commercialization appears as a new component in the value chain. It is a mercantile function, in which natural monopoly is not present. It does not request property of the distribution assets, although in many cases its owners also exercise it.

In the last years the Brazilian legislation of the electric energy industry suffered fundamental changes (Brazil, 1995). These include the following: end of guaranteed remuneration; end of tax equalization; set up a consumers's advice board; free access to the transmission net; changes in the rules of concession of the public services; inclusion of the system ELETROBRÁS (Centrais Elétricas Brasileiras S.A.) in the National Program of Privatization; end of market protection (introduction of the free market); and creation of the independent producer.

By the end of 1996 the Congress (Law 9.427, of Dec 27th 1996) created the Brazilian Electricity Regulatory Agency – ANEEL that was effectively implemented by the end of 1997. Another important step in terms of legal framework was taken in May 1998 by the Law 9,648, that stated the Wholesale Energy Market – MAE, created the Independent System Operator – ONS[2], instituted free purchasing of power for the distribution companies, create the retailer and defined the transition period for competition.

[2] ONS, Operador Nacional do Sistema is the Brazilian Independent System Operator

ANEEL and ONS are already in operation. Nowadays one of the main aspects of the Brazilian Electricity Industry restructuring is establish the Brazilian Wholesale Energy Market one pillar of the new model.

By April 2000, the Wholesale Energy Market Agent – ASMAE sent MAE rules for ANEEL appreciation, which should decide by July 2000. In agreement with this schedule the Brazilian Wholesale Energy Market should begin its operation next September. This research intended to improve my knowledge about this issue and help me in my work as Advisor to the Board of Directors in ANEEL in what refers to the MAE. Considering the relevance of this issue the paper is about the MAE.

The main objective of the present paper is to make known some probable basics trends of MAE in the near future. The first part of this paper describes the key issues of the Brazilian Electricity Industry restructuring that have already been defined. The second part will describe the market principle applied to electricity. The third part will present an overview of the International Experience in Wholesale Electricity Market. The forth and fifth parts will discuss the main aspects of Brazilian Energy Wholesale Market.

Finally the sixth part present the Government role in the new electricity industry and the last, but not least, reach the conclusion.

2 Key issues in the restructuring of the Brazilian Electricity Industry

To better understand the reform it is worth to analyze some aspects in terms of industry structure, transition period, competition and regulatory framework.

2.1 Industry structure

Traditionally the Brazilian power sector, as in other countries, had vertically integrated companies providing services in electricity industry. Most specifically, the production and long distance transmission activities, being capital intensive, were concentrated in four Federal companies[3] . These companies had monopoly to build all generation facilities in their area, except in some States of the South, Southeast Regions where there was a strong electricity company. In this case, the Federal Company was responsible to build the new plant only if it was on the border between two States. (Maia, 1999)

Geographical differences in the degree of development in Brazil directly influenced in the organization and topology of its electric system. In contrast to the South, Southeast and Center-west (80% of the market) interconnected systems, the North-northeast was developed by federal companies as regional monopoly of generation and transmission. This was caused by the fact that the area is less economically developed. The state concessionaires were limited to the distribution of energy (Ribeiro,1997). They did not accomplish a backward vertical integration, as happened in São Paulo, Minas Gerais, Paraná and Rio Grande do Sul. In addition, the generation in the Northeast is concentrated at the river São Francisco, while the only Northern power plant that is interconnected to the system is Tucuruí Hydroelectric.

One of the main pillars to introduce competition is the separation of activities in order to give more transparency to the market, avoid market power and information asymmetries, and to regulate the monopolistic activities while deregulating the competitive ones.

The Federal companies, as well as some state companies, are being separated in transmission utilities and generation companies before privatization. Not only the vertical separation is in course, the generation plants are also being restructured in smaller companies in order to avoid too much power in one company and promote more competition.

After reform, the electricity market in Brazil will be predominantly free and competitive. large consumers, retailers and distribution companies can already choose their suppliers, no matter where they are located. Purchasing of energy will be made at least in two manners: bilaterally contracting or in the Spot Market.

Bilateral Contracts between producer and retailer or consumer, or between retailer and consumer, will be agreed by parties concerning terms, price, duration, point of delivery, guarantees and other conditions, in a private environment. These contracts don't need to be approved or even registered by the regulator and will serve as a financial instrument to hedge both

[3] ELETROBRAS is the Federal holding company and had four regional subsidiaries: ELETROSUL, FURNAS, CHESF and ELETRONORTE. All of them own generation and major transmission facilities.

parts against fluctuations of spot price. In case of rationing, these contracts do not give any kind of preference on energy for the buyer. All the consumers in the region under rationing will be affected and will pay a higher spot price. Those consumers or retailers who have contracts to buy energy will be hedge against the spot price.

The only bilateral contracts that will be under supervision of the regulator are those agreed between distribution companies and their suppliers. In other words, the distributor is free to choose its supplier and define the price and conditions of energy purchased but it has to follow some rules to pass these prices on captive customer.

Producers, retailers and free consumers will need to buy or sell non-contracted energy resulting of differences between the energy contracted and that actually produced or needed. These differences will be cleared in a spot market in a multilateral trade mechanism that will define the spot price of energy in a half-hourly basis. The spot price will reflect the short run marginal cost to produce energy at each time and will represent the match between supply curve and demand curve.

The Brazilian Energy Market will be operated by the Wholesale Energy Market Agent – ASMAE. Taking into consideration the strong predominance of hydro plants, several of which in the same river or cascade, the power pool has to be cost-based. This means that the hydro producers will not be given freedom to bid their prices and willingness to produce.

All hydro plants will be coordinated by the Independent System Operator – ONS who will follow an optimization model that simulates the entire interconnected system behavior in the next 5 years. In this model of power pool, the economic dispatch is determined based on models run centrally by a dispatch center which receives information about costs and operation condition of all agents participating in the pool. The marginal cost of producing energy by a hydro plant reflects the cost of future rationing of energy.

The Figure 1 ,.presents a simplistic view of the Brazilian Electricity Industry Institutional Framework. With the main objective of benefits the consumers, the Policies will be set by the Congress, the Republic Presidency, the CNPE (National Council for Energy Policy) and SEN-MME (Energy National Secretary- Department of Mines and Energy.

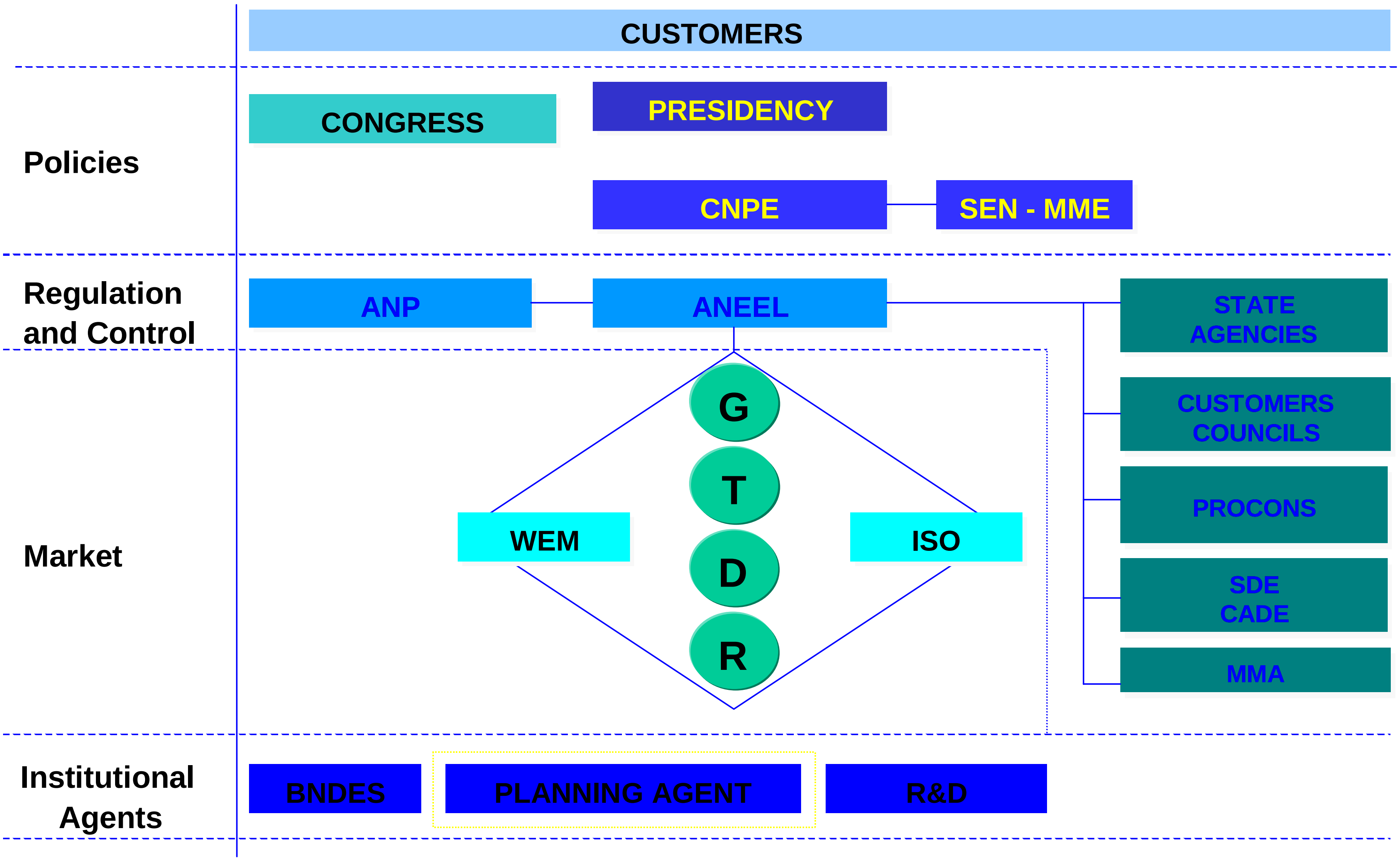
The regulation and control will be done mainly by ANEEL. Brazilian Gas and Oil Regulatory Agency (ANP) regulates the Natural Gas and Oil that could be used for Electricity production.

We also have:

- States Agencies (acting by ANEEL delegation in some aspects of distribution and retailing),
- Customers Councils,
- PROCONS (Consumers Protection Public Organization),
- SDE-MJ (Economic Defense Secretary – Department of Justice),
- CADE (Economic Defense Administrative Council), and
- MMA (Environment Department).

Figure 1

Institutional Framework



In the Market Structure we have the electricity generation, transmission, distribution and retail companies; the Wholesale Energy Market – MAE; and the Independent System Operator – ONS.

Others institutional agents are:

- Finance agent - BNDES(National Bank for Social and Economic Development);
- Planning Agent – CCPE (Brazilian Electric System Expansion Planning Committee);
- Research and Development Agents - Universities and CEPEL (Electric Power Research Center).

2.2 Transition period

To avoid turmoil introducing competition in electricity, a phase-in period was defined. For this period the regulator defined both prices and volumes, for the contracts that were to be signed between generators and distributors, called Initial Contracts. These contracts will lie in force until the end of 2005, but the amount of energy contracted for the years 2003, 2004 and 2005 will be based on the 2002 amount reduced by 25% each year.

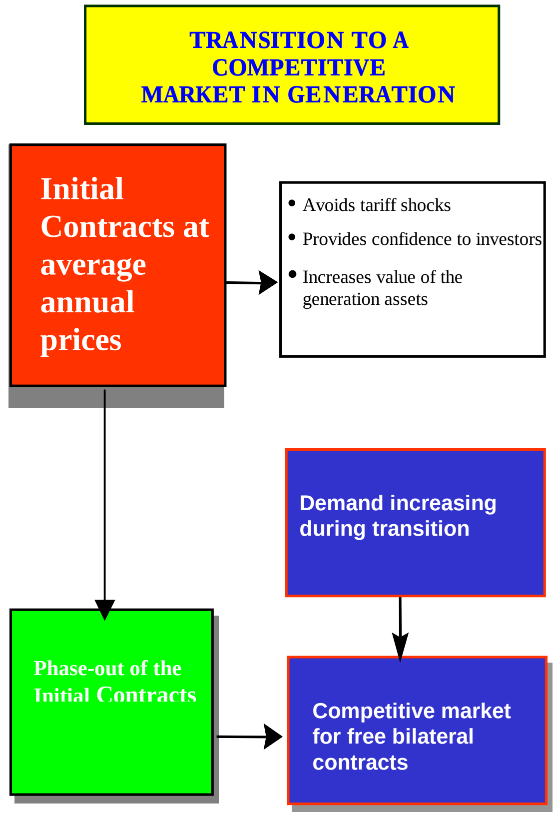
The prices of the Initial Contracts were sat by the regulator in order to avoid sudden rise in electricity prices for the final consumers. This means that the initial prices for generation could be less than a fair price or the marginal cost for a new power plant. However, considering that this price (or tariff) is only for the transition period and does not apply to new projects, it is expected that the market will not be distorted and the consumers will pay more for the additional need of energy.

Figure 2 shows the transition to a competitive generation market. To effectively promote competition in electricity it is essential that the monopoly segments, transmission and distribution, could be used by all participants in the market, without restriction or discrimination. This is the fundamental issue in a competitive environment.

In the Brazilian System, the transmission facilities are owned by several companies that are being restructured to be exclusively transmission companies. To coordinate the transmission system the solution was the creation of the ONS that will provide transmission services on behalf of transmission companies. All the users (generators, distributors, retailers, and large consumers) will contract with ONS the conditions to use the grid in accordance with the regulator provisions.

As the distribution companies remain operating in a competitive segment (retail), both the access tariffs and the energy prices to captive consumers must be regulated; otherwise there will be an asymmetry between competitors. To avoid this all users will contract with one area distributor in accordance with ANEEL’s provisions.

Figure 2



Source: MME (2000)

2.3 Brazilian Electricity Regulatory Agency - ANEEL

The Electric Energy National Agency – ANEEL created by the Law Nº 9.427 of December 26th, 1996 is a legal entity of Public Law under special federal regimen, linked to the Ministry of Mines and Energy, with headquarters and jurisdiction at the Capital District, and non-fixed duration.

The ANEEL aims at, granting of concessions, mediation, regulating and inspecting electric energy production, transmission, distribution and commercialization according to the policies and directives established by the Federal Government.

ANEEL duties are established in the article 3 of Law 9.427/1996 quoted below:

“ Article 3 - In addition to duties pursuant to articles 29 and 30, Law 8987, dated February, 13, 1995, applicable to electric energy services, ANEEL shall also be responsible for:

I - implementing Federal Government policies and directives for the exploitation of electric energy and the use of hydraulic potentials, issuing regulatory acts necessary for the observance of procedures as set forth by Law 9074, dated July,7, 1995;

II - carrying out public utilities tendering for the hiring of public utility concessionaires for electric energy production, transmission and distribution, as well as the granting of concessions for the use of hydraulic potentials;

III - defining the meaning of “optimal use” pursuant to paragraphs 2 and 3, Article 5, Law 9074, dated July,7, 1995;

IV - making and managing concession or permission agreements for electric energy public services and concession for public property use, issuing authorizations, as well as supervising, directly or through agreement with state entities, the concessions and the rendering of electric energy services;

V- clearing, at administrative level, divergences among utilities, permissionaire, authorized agents, independent producers and self-producers, as well as among those agents and their consumers;

VI- determining criteria for transport tariff calculation pursuant to Paragraph 6, Article 15, Law 9074, dated July, 7, 1995, and arbitrate their values in case of frustrated negotiation among agents involved;

VII - articulating, with the regulatory agency of fossil fuels and natural gas, the criteria for determining prices for the transportation of such fuels when for the purpose of generating electric energy, and for arbitrating its values in case of frustrated negotiation among agents involved.

The duties of the granting authority pursuant to articles 29 and 30, Law 8987, dated February, 13, 1995, applicable to electric energy services are the followings:

“Article 29. - It is incumbent upon the granting authority:

I - to regulate the service granted and to inspect, on a permanent basis, the rendering thereof;

II - to impose the regulatory and contractual penalties;

III - to intervene in the rendering of the service, in the cases and under the conditions set forth by law;

IV - to terminate the concession, in the cases set forth by law and in the manner established in the agreement;

V - to ratify adjustments and effect the revision of the tariffs pursuant to this law, the applicable rules and the agreement;

VI - to abide and make abide by the regulatory provisions of the service and the contractual clauses of the concession;

VII - to watch over the good quality of the service, to receive, investigate and settle complaints and claims by users, who shall be notified of the procedures adopted, within thirty days.

VIII - to declare those assets necessary to the performance of the public service or work as being of public interest and perform the corresponding expropriations, directly or through granting of powers to the concessionaire, in which event the later shall be liable for the applicable indemnification.

IX - to declare the need or public usefulness, for purposes of creation of public easement, of the assets necessary to the performance of the public service or work, and perform same, directly or through granting of powers to the concessionaire, in which event the later shall be liable for the applicable indemnification;

X - to foster the improvement of quality, productivity, environmental preservation and maintenance;
XI - to stimulate competition; and
XII - to stimulate the creation of users associations, for the protection of interests relating to the service.

Article 30. - For the performance of the inspection activities, the granting authority shall have access to the data pertaining to the administration, accounting, technical, economic and financial resources of the concessionaire.

Sole Paragraph - The inspection of the service shall be made through a technical body of the granting authority or through a hired entity, and shall be periodical, as set forth in regulatory rule, by a committee formed by representatives of the granting authority, concessionaire and users."

ANEEL mission is: " to provide favorable conditions to the development of the power sector with balance and fairness amongst the economic agents and the consumers, for the benefit of the Whole Brazilian society". (ANEEL,2000)

To comply with this mission ANEEL's main principles is the followings:

- meet society interests,
- guarantee fair competition,
- make clear and stable rules,
- guarantee adequate power supply,
- promote tariff fairness,
- act with transparency- Public Hearings,
- act in a non discriminatory form.

3 Market Principles Applied to Electricity

Markets are wonderful things for allocating scarce and hence valuable resources and commodities. But markets work well only when property rights are well-defined and can be traded and priced efficiently – requirements that are not always met without help from some very visible hands. Real competition in electricity is possible only to the extent that conscious efforts are made to develop property rights and markets that can deal adequately with the strong and nearly-instantaneous network interactions that characterize an integrated electricity system. (Ruff, 1999)

Markets do not themselves design, implement, or pay for everything they need to operate successfully. Particularly when new resources are being brought into the market and externalities are strong and complex, non-market processes play a large role in defining the role and form of markets and in providing much of what markets need to function. It is worth reviewing some of the areas in which markets need assistance from non-market processes.

Markets do not work well if the political environment is unstable or corrupt, if property rights are poorly defined or difficult to enforce, or if society in general is hostile to markets – although when these conditions are not met, no alternatives to markets work very well either. A supportive political, legal and social framework is generally taken for granted or is regarded as implicit in the other conditions listed below. But it is worth remembering that markets do not work well if some very basic conditions are not met

Markets do not function well without well-defined and enforceable rights to collect the benefits, and to be compensated for the costs – i.e., to internalize the benefits and costs – created by producing and trading scarce resources and costly services.

As electricity markets continue to develop, it will be necessary to define, allocate, price and trade ever-more-sophisticated property rights. These rights will not define themselves or emerge in socially acceptable form from private negotiations among the most directly interested parties. People who understand the needs of traders, the technical realities of the integrated electricity system and the public interest in efficient and open markets will have to come together in organized processes to decide what kinds of property rights make sense. These processes will often have to be conducted under the auspices of government, if only because legislatures and courts will have to resolve disputes over who initially owns newly defined property rights. And everybody operating on the same interconnected grid will have to use the same basic definition of property rights. (Ruff, 1999)

The conditions cited above under which markets work well are clearly not absolute, and will always be met only more-or-less well or poorly. But the obvious fact that markets are always imperfect does not demonstrate that there is a better alternative, much less define what such alternatives might be. Conversely, just because it is possible to create a market in something does not prove that it is worth the costs of doing so, rather than doing something else or nothing. Deciding when and how to institute a market involves complex trade-offs.

The trade-offs among tolerating externalities, letting a monopoly manage them, and creating efficient rights and prices to internalize them are more severe for electricity than they are in more traditional markets that have developed "naturally". Because all market participants are connected to the same grid on which power flows according to complex physical laws, externalities are potentially very strong and prices that fully and accurately internalized them all would be impossibly complex. The difficulty of pricing interactions on the common grid, more than the economies of scale in generation, prevented the development of competition in electricity until recently, and still limits the extent to which markets can replace monopoly control.

Eventually, simple contract trading developed among neighboring monopolies, but still without any actual pricing of network interactions. The selling monopolist would agree to deliver a certain amount of energy to the buying monopolist for an agreed price when asked to do so, and the buyer would simply integrate this source into its unpriced central dispatch process. As pressure for competitive generation developed in the United States in the 1970s and 1980s, this type of contract was extended to independent power producers (IPPs), so that an IPP could be paid for delivering energy to the local monopoly utility. But real competition, in which a generator could compete to sell directly to a consumer or to a distributor/retailer not affiliated with the local monopoly utility, did not develop until the 1990s.

For at least the last half-century, the principal obstacle to real competition in electricity has not been scale economies in generation, but the absence of market-clearing system prices to internalize complex network externalities. As long as only a few, cooperating monopolies are using the system, the externalities can be crudely controlled by simple administrative rules without much concern about the level or allocation of the resulting costs and benefits. But as competitors try to get into the market, the level and particularly the allocation of costs and benefits become critical. Without markets to internalize complex network externalities some regulated monopoly must manage them, and competition is stalled before it really begins.

The breakthrough that made real competition possible on an electricity grid was the concept of an independent system operator (ISO)[4] and a wholesale energy market (WEM) that operates a centralized spot market more-or-less integrated with real-time physical operations and open to competitive buyers, while managing all significant unpriced effects as a non-discriminating monopoly. The England and Wales Pool (1990) was the first well-known and widely imitated such system, but many others have been or are being developed around the world.

During the 1990s, electricity markets based on an ISO and an open, centralized spot market have been established in Norway (since expanded to include most of Scandinavia), Argentina, New Zealand, Colombia, Peru, Ukraine, Victoria (and subsequently all of eastern mainland Australia), Spain, Alberta, California, PJM (the Pennsylvania, New Jersey, Maryland power pool), New York, New England, Ontario and elsewhere.

[4] In Brazil the ISO is the Operador Nacional do Sistema (ONS) and the WEM is the Mercado Atacadista de Energia (MAE).

4 International Experience in Wholesale electricity Market

Over the past decade a number of nations have restructured their electricity industries. Several nations have also significantly reduced the government's role in the ownership and management of domestic electricity industries – both at the state and at national level.

I selected United Kingdom, Argentina, Norway and United States for this study because of the following reasons: United Kingdom was the first developed country that restructured its electric sector, Argentina , our partner in Mercosul[5], did a very deep restructuration of its electricity industry, Norway because its main electricity source is hydro like Brazil, and the United States because this huge country has some competitive power pools like California, New England an PJM (the Pennsylvania, New Jersey, Maryland power pool) already in operation.

4.1 United Kingdom

The United Kingdom (UK) offers an interesting case study into the process of electricity industry restructuring, privatization, and regulatory reform. The United Kingdom was one of the first nations to embark upon widespread privatization of its electric utilities. Although a growing number of nations have privatized their electricity industries since (or are currently undertaking such efforts), the UK's electricity privatization reform efforts have been among the world's most ambitious and path breaking. Several other nations have subsequently followed their example, using the UK experience as a policy guide in their own electricity restructuring, privatization, and regulatory reform efforts. (DOE,1997)

Electricity privatization in the United Kingdom has occurred in the larger context of the privatization of much of the formerly state-owned UK industries and the diminution of the central government's role in the national economy. The overall privatization of industry was initiated shortly after a conservative government came to power in the United Kingdom in 1979 under the leadership of Margaret Thatcher. A primary aim of the new administration was to reduce government's role in the economy. This goal has clearly been achieved. The share of employment accounted for by state-owned industries fell from 7 percent of total UK employment prior to privatization to less than 2 percent currently.

Partly due to the fact that the electricity industry strongly reflects the features of a natural monopoly, electricity was among the last and more controversial privatizations. British Aerospace was the first large industry to be auctioned off in 1981, followed by Cables and Wireless (1981), and by British Telecommunications (1984). Soon afterwards, British Gas (1986), British Airways (1987), British Steel (1988), and British water utilities (1989) were privatized. More recently, British Coal was privatized in 1995, and British Rail in 1996. As of 1995, the United Kingdom has raised over $95 billion through privatization.

Electricity privatization and reform got off to a relatively late start in the United Kingdom, having its origins in the passage of the UK's Electricity Act of 1989. The industry was

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[5] MERCOSUL is a free trade agreement where Brazil, Argentina, Paraguay and Uruguay are full members. Bolivia and Chile are associated members. Maybe this year this last two countries will become full members.

initially restructured by the government along functional lines. Guiding the government's restructuring was the idea that electricity generation and marketing could be made competitive industries, while transmission and distribution needed to be treated as natural monopolies for the indefinite future. Regulation would therefore gradually be withdrawn for the former segments but remain for the latter. For the still regulated segments, a new form of regulation (based on a price cap) was introduced-along with a new regulatory authority, the Office of Energy Regulation (OFFER). On Vesting Day (April 1, 1990) a newly-created electricity industry emerged.

The creation of a national wholesale electricity pool was another important area where the United Kingdom charted new ground in electricity reform. As in the United States, a major complication surrounding electricity reform in the United Kingdom was how to allocate the financial burdens associated with stranded costs. Stranded costs in the United Kingdom resulted largely from earlier investments in nuclear power and an overhang of high-priced coal contracts.

Although UK electricity reforms are not yet a decade old, some general assessments can be made regarding their performance. In terms of efficiency, the reform of the electric industry in the United Kingdom is generally viewed as a success. By any measure, the current industry is markedly more efficient than it was prior to privatization.

However, where issues of fairness and equity are concerned, the industry reforms have been controversial. The new system has been criticized for unfairly and disproportionately benefiting industry shareholders and corporate executives over taxpayers, rate payers, and electricity industry employees. The auction of electricity assets to the general public was criticized for failing to obtain the full value of the assets offered for the treasury. Further, a large share of the industry’s' efficiency gains was realized through massive workforce reductions. The fact that the heads of the newly-privatized companies were awarded substantial pay raises in the midst of these workforce reductions added to the controversy. Although electricity prices have generally trailed inflation in the intervening years since electricity reforms were implemented in 1990, electricity consumers have often felt less well treated than industry shareholders, who have realized profits well beyond those reported for UK industry in general over the same period of time.

4.1.1 The England and Wales Power Pool

In order to balance electricity supply and demand, the UK government instituted a power pool to act as a clearinghouse between suppliers of electricity (generators) and wholesale consumers of electricity (primarily the regional electricity distribution companies). The pool is open to all generators and consumers wishing to participate.

Those electric power generators whose capacity exceeds 100 megawatts are required to submit their generation units to dispatch by the National Grid Company (NGC). The NGC manages and operates the pool with an independent facility that attempts to balance supply and demand with an auction which roughly operates in the following manner. In the power pool every day is broken up into forty-eight half-hour segments. The system manager forecasts demand for each half-hour segment. Twenty-four hours in advance, generators submit bids for the various levels of power they are willing to supply at various prices and for various periods, for each half-hour period of the following day. The system manager then ranks these bids from least to most expensive. The system manager also calculates the minimum amount of generating capacity needed to meet demand projections. A merit order dispatch schedule is created whereby the cheapest generation units are selected first and supply is capped when enough generation units are selected into the system to cause generation capacity to be sufficient to supply one unit of energy over and above the forecasted demand. The pool purchase price for all suppliers becomes the highest price bid by the last generation facility needed to accommodate the last unit of demand. This balancing activity is an attempt to arrive at the electricity generation industry's marginal cost, or the system marginal price (SMP).

The price actually paid to generators also includes a financial incentive for maintaining some additional (peak load) generation capacity in the event that demand exceeds consumption forecasts. This capacity payment equals the value of lost load (VOLL) times the loss of load probability (LOLP). The VOLL attempts to measure the system cost of not producing enough electricity to meet peak load. Another way of looking at VOLL is that it attempts to measure the "extent to which generators are prepared to invest in additional capacity in excess of the actual maximum on the system." The LOLP simply measures the probability that supply will be insufficient to meet demand at a particular point in time.

The LOLP changes over the course of the year and the course of the day. The closer demand is to scheduled supply, the higher the LOLP and therefore the higher the capacity payment. The price paid to electricity suppliers is the pool input price (PIP), which equals SMP + (VOLL * LOLP). The price paid by purchasers is the pool output price (POP), which equals the PIP plus an uplift charge, calculated to cover certain ancillary functions, such as reserve plant availability, forecasting errors, transmission constraints, and marginal plant adjustments.

In practice, electricity prices in the England and Wales electricity pool have proven to be very volatile and subject to possible manipulation. Over time there have been several allegations that, due to their dominant position in the pool, National Power and PowerGen have been able to manipulate pool prices. According to these allegations, ownership of some relatively high-cost marginal plants have enabled the two dominant utilities to attempt to ensure that these units are offered up to the pool in such a way that they determine the SMP. The fact that both companies were once the same company suggests that each possesses an intimate understanding of the other's cost structure.

Thus, as a means of controlling price volatility, a hedging market has developed. This market (called the contract for differences market [CfD]) allows for bilateral contracts to be negotiated between generators and consumers.

The CfD evolved from contractual relations imposed on the industry by the UK government at Vesting Day (April 1, 1990). At the time, the two recently-privatized UK generation companies (National Power and PowerGen) were encumbered with contracts to purchase high-price British coal. In order to prevent other electricity generation companies (such as the recently-created independent power-producing companies) from capitalizing on this disadvantage, the regional electricity companies were required to purchase power from the two primary generation companies.

In the CfD market, generators and electricity purchasers can hedge pool prices by committing to a contract with an agreed-upon price, (the strike price). The strike price, for instance, may be set at an average of expected daily pool prices. If the strike price turns out to be higher than the daily average pool price, then the generator pays the purchaser the difference. Conversely, if the strike price turns out lower than the daily average pool price, the electricity purchaser reimburses the generator for the difference. In reality the CfD market uses a variety of different hedging contracts. Contracts for differences are purely financial contracts; however, in terms of hedging pool prices, they cover more than 90 percent of the electricity traded in the pool. Nonetheless, pool prices have still continued to be a source of controversy.

In February of 1994, in response to a sharp run up in pool prices in April of 1993, OFFER issued its first report on pool pricing activity. The report called for a two-year price cap and required National Power and PowerGen to sell off 6000 megawatts of generation capacity. Since February of 1994, OFFER has issued five reports on pool pricing.

4.2 Argentina

By 1992, Argentina's electricity industry had deteriorated badly and was characterized by severe operational and financial difficulties .The industry was constantly threatened with the possibility of blackouts, a threat which worsened during periods of relatively little rainfall (such as the summer) because of Argentina's reliance on hydroelectric power generation. Electricity was also expensive and often stolen by consumers either through illegal hook-ups or by failure to pay bills.

Despite these problems, the industry achieved a positive growth rate. For example, between 1985 and 1991, net production of electricity increased 19 percent, averaging slightly more than 3 percent annually. However, since privatization began in 1992, the growth rate of electricity production has doubled. Between 1992 and 1995, net production of electricity in Argentina has increased 22 percent, averaging slightly less than 7 percent annually. Argentina's electric industry problems included recurring power outages, substantial and regular unavailability of power generators, and rampant theft of electricity. Given these problems and Argentina's economy-wide problems, the dramatic increase in electricity production that has accompanied privatization demonstrates the extent of its effectiveness. (DOE, 1997)

Argentina's privatization was modeled after Chile's with modifications introduced to correct problems encountered by Chile. Argentina began privatization of its electricity industry more than ten years after Chile privatized its industry. The features of Chile's privatized electricity industry that Argentina adopted included open access to the wholesale electricity market guaranteed by law despite widely dispersed generation plants, and dispatch of electricity based on the production costs of the available generators, with the lowest-cost generation dispatched first. However, Argentina, unlike Chile, required complete separation of transmission from generation and distribution. Other willful differences in the privatizated industries of the two countries include Argentina's restriction that no single generator provide more than ten percent of national generation capacity.

In 1991, just prior to the beginning of privatization, Argentina's electricity industry included four federal utilities, one Argentina-Paraguay agency (controlling a large hydroelectric plant owned jointly by the two countries), one Argentina-Uruguay agency (also controlling a large hydroelectric plant owned jointly by the two countries), 19 provincial utilities, and several electricity cooperatives. One of the four federal utilities generated and distributed electricity to the greater Buenos Aires and La Plata area, one served the balance of the country's needs for power generation and transmission, one oversaw the hydroelectric power generators of southern Argentina, and one oversaw nuclear power generation plants. At the time of privatization, the non-nuclear utilities accounted for about 80 percent of the approximately 15,000-megawatt generation capacity of the system. Since 1992, at least some part of each of the first three former federally-owned utilities (the power generation branch of the national atomic energy agency is the lone exception) has been privatized.

4.2.1 The Argentina Power Pool

The wholesale electricity market (also known as a power pool) has both a supply side and a demand side. The supply side of the wholesale electricity market is composed of independent power producers, privatized generators, generators still owned by the federal government (including the two nuclear power plants), the two binational hydroelectric power plants (also still not privatized), and foreign producers selling imported electricity. The demand side of the wholesale market is composed of distribution companies, large users, and foreign consumers purchasing exported electricity. (DOE, 1997)

The interaction of the supply and demand sides of the wholesale market largely determines wholesale prices for electricity. Additionally, a fixed charge is added to all of the market-determined prices to cover payments made by Cammesa to power generators providing reserve capacity to the electricity grid. Three kinds of wholesale electricity prices exist in the Argentine electricity industry: contractual prices, seasonal prices, and spot prices. Of these, seasonal and spot prices are determined directly in the wholesale market, while contractual prices are affected indirectly by the wholesale market.

Use of the wholesale electricity market has increased substantially since its creation in 1992. For example, the number of exchanges taking place in the market has increased from approximately 20 (between February and April 1994) to around 450 (between November 1995 and January 1996). The number of participants in the wholesale market has demonstrated similar growth over the same period, particularly by large users, as total participants increased from about 50 (between February and April 1994) to more than 500 (between November 1995 and January 1996).

The wholesale market is administered by Cammesa, a nonprofit, independent operating agency jointly owned wholesale by the government and the power generation companies. Cammesa is directed by a board composed of two representatives from each of the following: Argentina's federal government, power generators, transmission companies, distribution companies, and large users. The board of directors makes decisions based on simple majority rule. (However, the president of the board of directors is the Secretary of Energy, who has veto power over board decisions and apparently can be overridden only by the President of Argentina.) Cammesa has three primary tasks: dispatching power; determining the fixed charges and other fixed fees added to spot, seasonal, and contractual prices to cover the full costs of transmission; and ensuring that the power system maintains adequate reserve capacity.

Power is dispatched to the national electricity grid by Cammesa. Cammesa determines the cost of generation for each producer and then dispatches electricity to the transmission grid, sending the cheapest power first until current demand has been satisfied. The price that is paid to each generator is determined largely by the highest cost producer whose power is dispatched . Revenues to fund Cammesa's operations may be no more than 3.5 percent of the gross revenues generated by the wholesale electricity market.

In Argentina electricity market we have three main prices: contractual, seasonal and spot. Contractual prices are negotiated between generation companies and distribution companies, or between generation companies and large users. The length of the contracts is typically one year. These prices are largely unregulated. Hydroelectric generators may contract only up to 70 percent of their anticipated monthly production. (Note that weather conditions and other factors may dramatically affect water levels and, therefore, the generation capacity of hydroelectric generators.) Similarly, thermal generators may not contract for more delivered electricity than their net generation capacity (some electricity use occurs at the generation facility.

Seasonal prices are determined by Cammesa in the seasonal component of the wholesale electricity market and officially maintained for 6-month periods, beginning May 1 and November 1 of each year. The seasons are based on water level and generally correspond to winter/spring and summer/fall, respectively. Every 3 months Cammesa receives updates to the information it uses to determine seasonal prices and may then revise the current seasonal price. Thus, seasonal prices are effectively 3-month prices.

Cammesa sets seasonal prices by using information provided by distribution, transmission, and generation companies. The information includes demand forecasts for typical days, unavailable reactive power, and weekly load curves from distribution companies; availability, restrictions, reactive power equipment unavailable, and net equipment information from transmission companies; capacity, efficiency, planned maintenance, internal electricity consumption, and availability from all generation companies; fuel use and prices from thermal generation companies; and historical and predicted water flows and other characteristics of the reservoirs from hydroelectric generation companies.

The seasonal price is paid by distribution companies purchasing power in excess of the amount they had contracted to purchase from power generators. Seasonal prices during the winter/spring presume that hydroelectric generators are the primary source of power and have lower seasonal prices than the summer/fall period. Alternatively, seasonal prices during the summer/fall presume that thermal generators are the largest source of power and have relatively higher prices.

Spot prices are determined by the interaction of buyers and sellers in the spot component of the wholesale electricity market. Spot prices vary hourly. The buyers who pay the spot price include generators and large users. Generators buy electricity they contractually agreed to provide in excess of actual generation. Additionally, large users who contracted for too little power to cover their current need may purchase additional electricity in the wholesale market, paying the spot price.

Sellers receive the spot price and may include distribution companies, generators, and large users. Distribution companies contracting for more electricity than actually purchased by their customers may sell their excess electricity in the spot market. Similarly, generators may sell electricity produced beyond their contractual obligations (to either distribution companies or large users) in the spot market. Large users, too, may sell any electricity they have contracted to buy that exceeds their current use, receiving the spot price.

Spot prices received are adjusted through application of fixed charges. These charges are assessed by Cammesa and are to cover the costs of ensuring some minimum level of reserve capacity and coverage of transmission and other losses.

Reserve capacity provided by thermal generators is based on the level of undispatched, but available, capacity they provide. Hydroelectric generators are paid on the basis of the amount of power generated. Reserve capacity is assigned on the basis of least-cost generation.

Transmission loss charges are based on the physical distance of the electricity seller from Buenos Aires. The greater the distance, the more the price received is discounted to cover transmission losses.

As of May 1996, the base price paid for electricity dispatched by Cammesa was $5 per megawatt hour and the fee paid for reserve capacity also was $5 per megawatt hour, summing to $10 per megawatt hour.

Following privatization, Argentine wholesale electricity prices fell about 60 percent from the pre-privatization level of $60 per megawatt hour in August 1992. As of 1997, Argentina's wholesale power rates stabilized at about 40 percent below the pre-privatization level. However, this occurred only after a period of adjustment, during which wholesale rates fell almost to zero.

Increased reliability of electricity service has been substantial in some cases. For example, the northern Buenos Aires distribution company reduced outages from 22 hours per year in 1992 to 6 hours per year in 1995. Meanwhile, the southern Buenos Aires distribution company cut outages from 39 hours per year to 6 hours per year over the same period.

Reliability also has been increased through the introduction of improved technology. For example, following privatization, incumbent generating plants were retrofitted with power system stabilizers. Once the stabilizers were in place, a system to automatically disconnect generating capacity could be designed. Transmission faults were then less likely to cause widespread outages because the automatic system disconnects as little generating capacity as possible, given the particular transmission fault.

4.3 Norway

Although most of the assets in the Norwegian electricity industry are publicly-owned, there is no single public owner. Municipal bodies as well as state companies own both generation and distribution assets. Hence, there is competition between plants, even though privatization has not figured large in the Norwegian reforms. Reforms have been aimed at creating incentives for more commercial and more efficient behavior, driven by market pressures and best practice incentive regulation. Expanding competition was intended to allow more rational use of hydro resources, and ensure better cost signaling through the geographic variation in prices. The government feared that some municipalities might be hoarding cheap water, whilst others were going short, due to a lack of trading opportunities. Reform was also aimed at achieving greater equity, by giving more customers access to competitive electricity markets, and avoiding cross-subsidization between different groups.

Electricity generation in Norway is almost exclusively hydro-based. In 1990, hydro plant amounted to just under 27 GW of installed capacity (compared with just 250 MW of thermal plant) and contributed over 99 percent of the 122 TWh of electricity produced. Power intensive industries accounted for around 30 percent of Norwegian electricity consumption in 1990, while households also accounted for around 30 percent of demand. Average household consumption is very high by international standards, at over 7000 kWh a year.

Asset ownership has been characterized by considerable fragmentation, with over 300 separate companies, largely owned by local municipalities. There is also considerable vertical integration in the sector, with around half of the 200 or so distribution companies also owning generating facilities; even where full vertical integration had not occurred, long-term contracts formed strong vertical ties between companies. Before the reform, Statkraft, the largest state-owned generator, owned 80 percent of the high-voltage transmission grid. (NERA, 1999)

Until 1991, electricity was traded on two levels: in a pool, and by contract. Electricity companies with generation facilities were allowed to buy and sell in the "Samskjøring," an electricity pool established as a producers' club in 1971. The distribution and regional grid companies had a *de facto* monopoly over final customers within a certain area. Tariffs and long-term contracts were subject to "cost of service" regulation. Any costs not covered by the low pool price could therefore be passed on to these customers.

Major reform of the Norwegian electricity sector came into effect in January 1991. The Energy Act of 1990 paved the way for a market-based production and trading system, with competition as the means of allocating resources, and a more light-handed regulatory regime substituting for intrusive regulation. Regulation was effectively confined to the monopoly network businesses. As part of the reform, the high-voltage transmission network, which had been part of the major state-owned power company Statkraft, was separated into a new state-owned company, Statnett. Statkraft was reorganized as a commercially oriented generator.

The reform also opened access to the pool to all generators and consumers. Thus any consumer could, in principle, purchase their electricity from the spot market. A new Norwegian power pool was established in 1993, organized by Statnett Marked, a subsidiary of the grid company. In January 1996, this power pool was expanded to include Sweden, with the Swedish transmission company Svenska Kraftnat taking a 50 percent stake in the new pool company, Nordpool, in April 1996. Nordpool now organizes day-ahead and futures markets. Since April 1997, the regulation market for real time balance in Norway has been operated by Statnett.

The Energy Act gave all suppliers in Norway the right to sell power across all networks. However, a new supplier had to pay the local network owner a fee for each customer who switched, to cover the cost of the additional hourly metering required. This fee was initially capped at 5000 NOK[6] per end-user. Since 1991, NVE (the regulator) has introduced measures to enhance retail competition, as a way of putting further pressure on municipal and other electricity companies. For example, from 1995 the requirement for hourly metering was eliminated for customers with annual demand below 500 MWh, a standard load curve being used to "impute"

[6] NOK = Norwegian Krone. There were approximately 7 NOK per US dollar in 1997.

consumption instead. (Grid owners were, however, allowed to charge each consumer up to 246 NOK for each switch of supplier.) All switching fees were eliminated in 1997. From 1998, customers were entitled to switch supplier on a weekly basis.

Recently, NVE switched from cost of service regulation to price cap regulation (with profit sharing outside a dead band). The effects of the new regulatory approach are not yet evident, but NVE is already concerned about maintaining long-term investment incentives.

Despite a rapid and extensive process of reform, ownership of the Norwegian electricity sector remains largely in public sector hands. In 1996, over 90 percent of generating capacity and networks were owned by either central government, counties or municipalities.

Vertical integration also remains common. Of the 326 separate utilities identified in the electricity sector in 1996, over 100 were classified as integrated (i.e. include generation and distribution assets). Since restructuring, a number of pure electricity marketers have also emerged in the market, although most act as brokers, rather than taking a position on their own behalf. There remain around 130 separate generating entities in the Norwegian system (of which around 50 supply their own needs only). The largest is the state-owned Statkraft, which had a market share of around 30 percent in 1995.

A market survey conducted by the regulator in 1997 found that suppliers sourced around 37 percent of their electricity needs from their own generating capacity and 40 percent through fixed price contracts. Direct purchases on the spot market accounted for around 20 percent of purchases. The spot price exhibits considerable fluctuation, depending crucially on hydro conditions.

Over-investment in expensive capacity, encouraged by the previous monopoly regulatory regime, is likely to result in depressed prices in the competitive market. As competition was introduced without explicit mechanisms for recovering the cost of past investments, this created financial problems for several municipalities "stranded costs." Those utilities which had recently constructed hydro generation facilities found it difficult to recover their costs in the new market conditions. (New hydro facilities, often built for social rather than commercial reasons, tended to be built in more expensive locations than existing facilities.)

4.4 United States

The US electricity industry is the largest in the world and one of the most fragmented. It is currently moving towards deregulation of its electricity utilities, state by state. This transition is complicated by a myriad of jurisdictions, both state and federal, and by the private ownership of most of the industry. The US is not the leader in the transition to full competition — its first official proposals for retail competition were made in 1994 — but it has had previous experience with several forms of competition, the failures of which are educational. (NERA, 1999)

In the five years since the first reform was announced, 47 states have conducted an analysis of reform proposals; 18 states have adopted a plan for reform and five states have gone all the way to introducing choice for customers. Approximately 33,933 MW of generating plant has been divested; and plans to build 30,271 MW of new merchant plant have been announced.

To understand the context of the present reform efforts, it is necessary to describe the important changes in the regulation of the US electricity industry over the past years. The US industry has traditionally consisted of about 100 privately owned, vertically integrated monopolies (Investor Owned Utilities or IOUs), each serving a defined service territory. IOUs generate about 75 percent of power in the US.[7] Each state government long ago set up an independent regulator to regulate the IOUs in its own state.

There are also about ten large government-owned generating companies, initially created to develop major hydro resources, although some also own other plants. In addition, there are approximately 3,000 local government-owned distribution utilities (municipalities or munis), some of which also own generation facilities. Most municipalities are small, but notable exceptions include Los Angeles Department of Water and Power, which serves much of the LA basin. Municipalities generally purchase their power requirements from the IOUs and the government-owned generators. These wholesale transactions are regulated by FERC (the Federal Energy Regulatory Commission), which also sets the prices and conditions of transmission access throughout the US. (FERC, 2000)

The reforms currently underway in the restructuring states generally permit some or all retail customers to choose their suppliers. As mentioned previously, the reforming states are generally those with the highest prices. Since, under US regulation, high prices are the result of high utility costs which are passed on to customers, the aim is to lower costs through competition. For example, in California, the State's regulatory body, the California Public Utilities Commission (CPUC), was clear in citing that its primary objective in introducing electricity reform was to lower the price of electricity for both residential and business customers.[8] The CPUC also noted that the current regulatory structure failed to offer utilities the proper incentives to operate and invest efficiently. Other states have cited similar objectives.

The main vehicle for lowering consumer electricity costs is to deregulate the generation market, forcing generators to compete with each other, and reducing the influence of the state commissions on generation investment. In the US, the state commissions continue to regulate charges for distribution and prices to consumers who competitive retail providers do not want to serve (e.g. low-income customers, rural customers with few competitive alternatives). The reforms require several types of change: arrangements for recovery of stranded costs, new trading arrangements, and provisions for control of market power in the deregulated generation market are the most obvious. The restructuring of the electric industry has also led to divestiture of generation assets and an influx of proposals for building merchant plant. (Cameron, 2000)

4.4.1 Trading Arrangements

The reforms have led to substantial changes in the trading arrangements. These changes are far from complete. FERC, which has jurisdiction over transmission prices, has been attempting to encourage consolidation of the multiple transmission systems into regional

[7] Energy Information Administration, Form 759, 1997.

[8] Proposed Policy Statement on Restructuring California's Electric Services Industry and Reforming Regulatory Policy, CPUC, April 20, 1994.

organizations (Independent System Operators). Operation of the transmission system (control of the dispatch) is gradually being passed to regional Independent System Operators (ISOs). But even the strong historical precedent of bilateral trading, the FERC's regulation does not yet completely reflect the FERC, the different requirements for retail competition, and the need for visible, transparent spot market prices.

However, while FERC is not leading the changes, it has permitted fairly radical revisions to traditional trading structures: it has approved (with some reservations) the institution of ISOs in California, New England[9], New York and PJM (the Pennsylvania, New Jersey, Maryland Interconnection). These four systems have also adopted "pooling"[10] as the trading system, rather than the bilateral trading model that characterized the period of wholesale competition, and which led to such extensive litigation. FERC has approved the pooling form of trading system.[11]

As of early 1999, the four US pools currently in operation all have slightly different rules, and all are still being refined. While some areas of the US are still attempting to develop ISOs that build on the bilateral trading model it is noteworthy that the only states that have implemented retail competition are states where generators have access to a pool or spot market. States that originally were on a fast-track toward competition, such as Michigan and Arizona, have had to delay market inception. Michigan expected to begin phasing in retail competition in 1997, but has delayed it until at least mid-1999. Plans to develop a Midwest ISO have largely been sidetracked. Arizona was expected to begin its retail market in January 1999, but the state has suspended the beginning of retail competition in until January 2000. The development of a southwest ISO, Desert Star, has also been delayed. The status of ISOs in development or in operation in the US is shown in Figure 3.

FERC, and some of the state Commissions, have required analyses of market power before permitting new trading arrangements to come into effect. In some areas there are sufficient IOUs and sufficient transmission interconnection to enable a considerable amount of competition. However, in other regions, divestiture of some of the IOUs' plants is a pre-requisite to introducing a legitimately competitive generation market. (Maryland, 2000)

In California, two of the state's three IOUs were required to divest or spin off 50 percent of their thermal generation located in the state. Incentives were provided for additional divestiture. All three IOUs (Southern California Edison, Pacific Gas & Electric and San Diego Gas & Electric) subsequently decided to sell off all of their in-state thermal generation. The decision by California IOUs to divest is this reason for divesting generation is distinct from divestiture to determine stranded costs. As time has gone on, companies have decided for themselves to sell their plant rather than be "encouraged" to do so. In the case of California, divestiture was in part motivated by financial incentives that the CPUC offered IOUs to divest.

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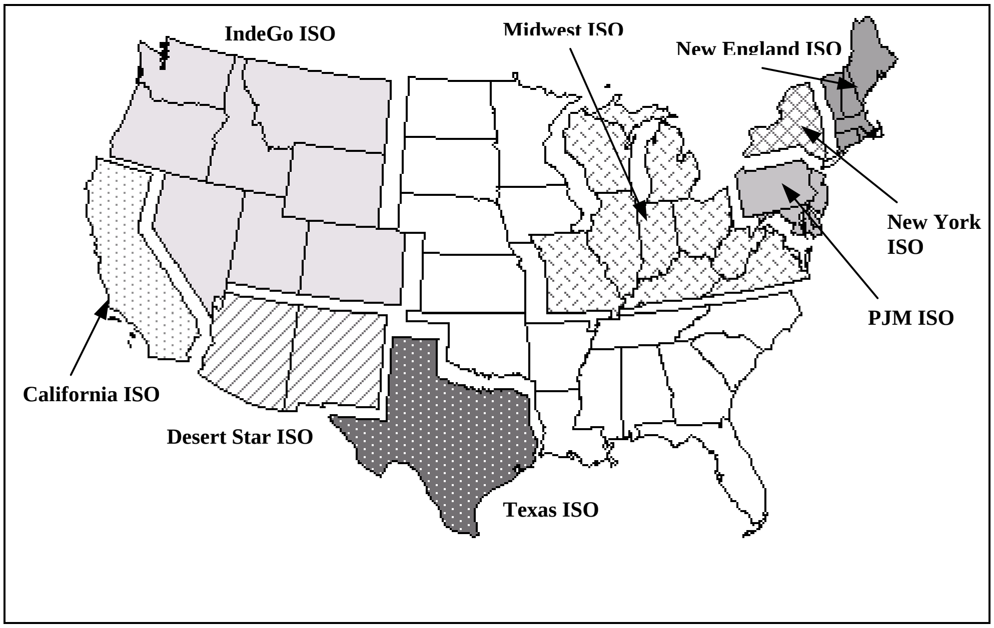
[9] New England refers to the following states: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont.

[10] The simplest characterization of the difference is that the "pooling" model for wholesale trade incorporates a spot market as a central feature, while the bilateral market model does not.

[11] For example, prior to the reforms IOUs in New England, and New York all had regional pools - NEPOOL, PJM, and NYPP, respectively - that operated as "tight pools," whereby generation plants were dispatched, based on costs, to meet aggregate load in the region. In California, a pool system was developed to accommodate reforms. A statewide Power Exchange (PX) was formed and operates forward energy markets.

Figure 3: Independent System Operators (ISOs) in the United States



Note: The IndeGo ISO has currently suspended development. Portions of Texas and Nevada are also part of the Desert Star ISO. Part of New Jersey is included in the New York ISO. Portions of Maryland and Pennsylvania are included in the Midwest ISO. Delays in the midwest ISO has sparked the "Alliance," ISO formed by a group of utilities in Michigan, Ohio and Virginia.

The reforms have not generally required the IOUs to split their operations into separate generation, distribution and transmission companies. In addition, most state commissions have permitted utilities to develop their own unregulated retail energy subsidiaries to compete with other firms in the deregulated retail electricity market. However, the regulatory commissions have required separate accounting for each of the subsidiary activities and for retail sales costs. "Codes of Conduct" are used to limit the amount of use a deregulated subsidiary may make of a regulated subsidiary's assets, personnel and reputation.

Without exception, transmission assets continue to be owned by the original IOUs. However, transmission owners in the pools have handed over their dispatch control to the ISO. There have been some suggestions of consolidating transmission assets into separate regional companies (Transcos), but this has not been enacted anywhere. The proposals so far have been for a separate affiliate of large integrated companies. These proposals are unlikely to succeed because FERC will not consider affiliate Transcos sufficiently independent.

Finally, regulation of distribution, as well as bundled tariff services to consumers, remains in the jurisdiction of the states' regulatory agencies. Regulation of transmission prices and of the design, development, implementation and operations of power pools and ISOs is the domain of the FERC. Regulation of market power continues to be divided between FERC, each State and the Justice Department.

5 The Wholesale Electricity Market Agreement

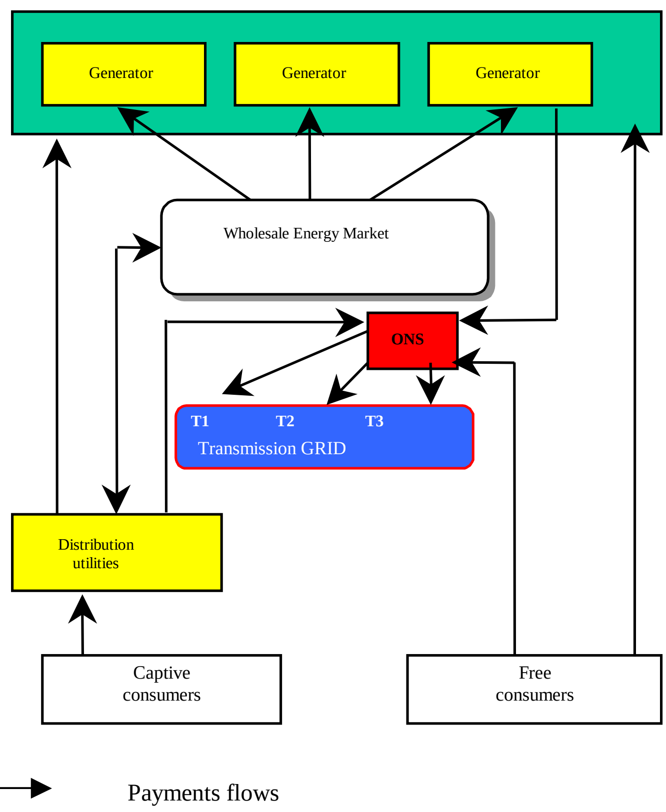
The creation of the Wholesale Electric Market (MAE) and the Independent National System Operator (ONS), under the management of sector agents, in a balanced structure that takes into account the interests of sellers and buyers, transfers the responsibilities and the decisions to the market players.

A favorable environment for the free trading of electricity in a wholesale market has been created due to the segmentation of the areas: generation, transmission, distribution and retailing.

In this sense, transparent prices are established via competition. The difference of prices according to the region gives more flexibility to the energy transactions and long term contracting and the availability of adequate signals to guide the decisions about the competitive expansion of the generation sector.

In this sense the new competitive model for the Brazilian Electricity sector is showed below (Figure 4) . The Wholesale Energy Market (MAE) is major component of this model.

Figure 4: The new Competitive Model for the Brazilian Electricity Industry



Fonte: MME (2000)

Clear rules of participation and association will assure the free entrance of new generators, allowing them to get non-discriminatory treatment in setting contract differences. The establishment of competition among the generators (present and future) will contribute to the reduction of costs in the most capital-intensive segment of the electric energy industry, what will benefit the final consumer.

The correct pricing signaling – hours by hours and season by season - will reflect the variation in hydrologic conditions, constituting an effective economic signal to define the priorities needs for new investment. This way, the development of unnecessary projects will be avoided leading to a reduction of the total investments demand resulting in an increase of the competitiveness of the Brazilian economy.

The MAE is the environment where the buying and selling electric power transaction will be accomplished and it was instructed by Agreement among the Market Agents. It is up to ANEEL to confirm the Market Agreement the Market Rules, as well as its alterations.

According with ANEEL's Resolution 249/98 and the Market Agreement a percentile minimum (85 %) of the amount of energy traded with final consumers should be covered by Assured Energy of own plants or by long term (above two years) purchase energy contracts.

6 Key Issues in the Brazilian Wholesale Market

During the discussion about the MAE Rules the following five points were highlighted:

- pricing and settlement system;
- energy reallocation mechanism (ERM);
- surplus allocation;
- capacity fee;
- demand side bidding.

Due to the importance of these points for a good operation of an electric power market, the same ones were chosen for be approached in this paper.

As already presented in chapter four, over the past decade a number of nations have restructured their electricity industries. The design of the MAE Rules took advantages of these experiences. In particular were important the experiences of the following countries: United Kingdom, Argentina, Norway and United States.

6.1 Pricing and settlement system

According to the document MAE Rules – General Overview, emitted by ASMAE[12] , in November of 1999 the MAE's price will be defined Ex-post , based on demand and availability realized. Realized demand means measured demand of all that traded in the MAE, more any reduction of demand ordered by ONS. Realized availability means the last one declared by a generator, demand side bidder, or interconnection operator, being considered any eventual flaw happened in the real dispatch. (ASMAE, 1999)

It is important to point out that the Market Agreement, signed by all agents already established, set up that the price would be determined Ex-ante, based on the declarations of availability presented in the previous day and in the foreseen demand.

Here it will be analyzed the implications of that proposal and verified if a better solution doesn't exist in agreement with the state of the art of the electric power markets that are in operation in the world. It is important highlight that a basic choice in any energy market is the pricing settlement system.

An ***ex-ante***, or forward, market involves sales and purchases made in advance of the actual consumption and generation that takes place. Ex-ante markets fix the price at which customers will be charged and generators will be paid in advance of their actual consumption. The quantities bought and sold are based on the purchaser's forecast of their consumption and the generators forecast of their availability. In an ex-ante market, generators and customers make firm financial commitments to buy or sell the scheduled quantities at the ex-ante market price. (Fraser et. ali, 1998)

[12] ASMAE – Administradora de Serviços do Mercado Atacadista de Energia Elétrica

In general, actual consumption and generation will not match the quantity bought and sold in the ex-ante market. Demand forecasts are inaccurate. Generators may not be available to generate due to operational problems. The actual load and the generation resources used to meet that load may therefore differ from the ex-ante market. Hence, with an ex-ante market, there needs to be a mechanism to account for and price the deviations from the ex-ante quantities. An ex-post market is one way to achieve this objective.

An ***ex-post***, or real-time, market is a market that takes place coincident with the real-time dispatch. The prices from this market reflect the actual consumption and generation that happened during the time period. The ONS will dispatch available generation (and dispatchable load) according to their costs (or in the case of demand bidding-their bids). After the fact, the ONS will determine what happened on the system, by looking at actual generation and load. The ex-post price is set equal to the cost (or the bid) of the highest priced resource dispatched during the pricing period, for example one hour. The quantities bought and sold in the ex-post market will be based on the actual metered output of the generators, and the actual metered consumption of the customers.

The advantages of ex-ante markets are as follows:

- they facilitate the incorporation of demand side bidding;

- they provide price assurance to both customers and generators, prior to the real-time dispatch. This is particularly important for purchasers and thermal generators, that may have fixed start-up costs that they want to be sure of recovering before committing to start, but is less important for hydro generation;

- ex-ante markets reduce the ability of generators to game their availability (provided that real-time deviations from the ex-ante commitments are priced at marginal cost). If they are not available to generate, generators purchase the replacement power at their bid prices. If a generator has made a sale in the ex-ante market and is not available to generate to meet this commitment, it must purchase the replacement power to meet its obligation. If the cost of the replacement power is more expensive than the ex-ante price, the generator cannot gain by gaming its availability.

One disadvantages to ex-ante markets is that: Ex-ante markets require a mechanism to price deviations from the ex-ante quantities, for example an ex-post market, or some other mechanism. There are gaming opportunities for generators if deviations from ex-ante quantities are priced other than at the marginal cost of the replacement power.

One advantage of an ex-post market is that: prices in the ex-post market reflect the marginal costs of meeting actual load.

The disadvantages of an ex-post market are as follows:

- without any advance commitments in an ex-ante market, generators do not face financial penalties for not being available for dispatch. This may lead to gaming opportunities for generators with large portfolios to manipulate their availability;

- it is more difficult to incorporate demand bidding into ex-post markets. Demand bids can be used to set prices and ration capacity only if they are dispatchable by the ONS.

Combining an ex-ante and ex-post market combines the benefits of both described above. An ex-post market prices deviations from ex-ante commitments at the marginal cost of meeting those changes. Only generators and customers that deviate from their pre-scheduled commitments pay any additional costs imposed on the system. This reduces the incentives for generators to game their availability. If a generator is not available for dispatch, they are responsible for the additional costs they impose on the system, through the requirement to purchase make-up power at the spot market price. Similarly customers who consume additional power in the real-time dispatch will pay any higher prices associated with the higher consumption. Customers that purchased all their requirements in the ex-ante markets will be unaffected by real-time variations.

Ex-ante, ex-post, and a combination of ex-ante and ex-post markets are currently in operation throughout the world. Victoria, Australia, and Alberta, Canada have a single ex-post market.

The England and Wales Pool operates a variation on ex-ante markets. While the Pool produces a day-ahead schedule, this does not reflect a firm financial commitment by either generators or customers. Customers pay according to their actual consumption. Generators are not penalized for not being available, even when they have been included in the day-ahead schedule. The way in which the LOLP*VOLL payment was calculated also encouraged generators not to submit bids day-ahead, in order to increase LOLP, and then re-declare their availability, to receive the payment.

Nowadays the Wholesale Energy Market has a clear tendency of use one combination of ex-ante and ex-post market. These multi-settlement system is used in: Norpool (Norway, Sweden, Denmark), California, New Zealand, Spain, PJM (Pennsylvania, New Jersey and Maryland,), New England and New York Power Pool.

In multi-settlement system, the day-ahead bids are used for both scheduling and settling day-ahead transactions. Only deviations from the day-ahead schedule are priced ex-post.

The purpose of the multi-settlement system can be seen in an example. If a generator fails to deliver, then other generators will be increased , pushing up the spot price. The generator pays a penalty equal to the difference between the spot price and the day-ahead prices times the quantity the generator failed to deliver.

The single-settlement system may appear simpler than multi-settlement system. First, it involves just a single set of hourly prices. However , this simplicity is deceptive. The difficulty with the single ex-post settlement is that much is riding on the ex post prices, since all earlier commitments and transactions are settled at the prices established in real time. After the day-ahead schedule is formed, bidders have an incentive to make adjustments to influence the spot price in a favorable direction. Bidders can take advantage of short-term inelasticities in the supply schedule to reap excess profits. Knowing how to do this is complex, and can be exploited best by large bidders with sufficient scale to make the efforts worthwhile. The added complexity and risk tends to discourage entry and participation by small bidders whose net revenue might be whipsawed by price volatility in the real-time market. (Cramton&Wilson, 1998)

This gaming can be mitigated by financial penalties for failures to perform as scheduled. But then the question is: How to set the penalties ? Some flexibility is needed because of uncertainties in demand and supply. Setting the penalties too high leads to inefficient responses to this uncertainty, and setting the penalties too low leads to excessive gaming. The reliance on penalties is highly inefficient and problematic in its workings.

A multi-settlement system mitigates gaming on two fronts. First, the day-ahead bids are binding financial commitments. The bids and resulting schedules are credible precisely because they are financially binding. Second, bidders are unable to alter the day-ahead prices. These remain fixed for all transactions scheduled in the day-ahead market. Deviations from the day-ahead schedule affect the spot price, but the spot price is used only to price these deviations. Hence, in a multi-settlement system the incentive to manipulate the spot price is not magnified as it is in a single-settlement system.

Penalties for non-performance are not needed in a multi-settlement system, since deviations from the schedule are priced correctly. If a generator fails to deliver as scheduled, then that generator is liable for the spot price for the quantity it was supposed to deliver.

The multi-settlement system reduces risk for the bidders, mainly the demand – side bidders, since they can lock in the day-ahead prices. For the MAE and the ONS, the multi-settlement system reduces scheduling uncertainty because it discourages schedule changes, and it automatically sets the right penalties for non-performance. The system maintains the flexibility required to respond efficiently to fluctuations in demand and supply.

A difficulty with the multi-settlement system is that involves multiple prices for energy. One might think that energy at a particular time (and place) should have one price. However, this is not correct. The price should be determined at the time resources are committed. Hence, if there are two commitment points (day-ahead based on forecasts and real-time based on events), then there should be two prices, one a forward price for early commitments and a second that recognizes the effects of contingencies.

For the reasons outlined above, It is suggested that the MAE should adopt a combination of ex-ante and ex-post markets. The efficiency advantages of the ex-ante market outweigh the drawbacks associated with a more complicated settlement mechanism. An Ex-ante market is best combined with an ex-post market, to prevent gaming of generator availability and demand bids.

6.2 Energy Reallocation Mechanism (ERM)

From the theoretical point of view, in the case of hydrothermal systems there should be separate spot markets for power and water transactions. One alternative to represent the effect of this water market is to sign contracts between hydro plants and upstream agents, where a proportion K of the plant generation is reassigned to the reservoirs, which would then collect the corresponding revenues. For example, K could be calculated as the ratio between the expected net payments to upstream reservoirs and the expected remuneration from energy sales along the planning period. The allocation of this reassigned energy among upstream reservoirs would analogously be in proportion to their expected revenues.

In the case of the Brazilian system, this cross contracting, although conceptually feasible, is made very complex due to the large number of reservoirs belonging to different agents. A simplified allocation rule was then proposed in which in each hydro plant gets an energy credit in proportion to its contribution to the system firm supply capacity, which is the maximum load that can be supplied by the hydro system under a given risk level. The energy credit, is calculated as the difference between system firm capacity with and without each hydro plant and reservoir individually (there is a small adjustment to ensure that the sum of energy credits is equal to the total system supply capability). In other words, individual hydro generation at each stage is summed and the total hydro production is reassigned as energy credits allocated among all hydro plants.

The ERM (Energy Reallocation Mechanism) ensures that, under normal operating conditions, hydro generators will receive the income associated with their assured energy through the reallocation of generation from those in surplus to those in deficit. To ensure fairness and transparency, the ERM rules will be part of the WEM.

The ERM will operate as follows:

- The ERM will guarantee hydro generators their assured energy entitlement provided that, in aggregate, hydro generators within the ERM produce enough to meet their total assured energy. It will reallocate output from that plant generating above their assured levels to those generating below;

- the price at which the reallocation is made will be a low one, reflecting hydro generators variable operational costs and royalties only. It will be set by ANEEL at this level to make hydro generators indifferent to the level of output they produce, since they will be assured of the income associated with their assured energy under normal system conditions.

- if total actual hydro generation exceeds total assured energy (i.e. “secondary energy” is produced), the surplus will be shared by all hydro generators according to one MAE rule.

- if hydro generators as a whole do not generate up to their assured energy, they shall purchase the shortfall at the prevailing MAE price or under contract.

- during periods of shortage, there may not be sufficient total system generation to meet assured generation levels for hydro plants. Hydro generators will therefore have a MAE exposure at the rationing price. The ERM will give all hydro generators the same proportional exposure, and hence the risks for an individual generator will be much less than if each generator had an exposure related to its own generation.

To ensure transparency and to avoid potential exclusion of new hydro generators, any changes to the ERM will be subject to agreement by MAE market members and ANEEL, as with any amendments to the MAE rules.

Assured energy values in the ERM will be assessed periodically to ensure that they remain reasonably reflective of actual system conditions. Revisions shall not take place too frequently, since this could create a disincentive for new investment in hydro plant. Therefore, a recommendation has been made that a revision take place every 5 to 10 years for existing plant. New plant should have their assured energy fixed for 15 years.

6.2.1 Secondary Energy allocation in the ERM

According to the document MAE Rules – General Overview, emitted by ASMAE , in November, 1999 the MAE will allocate the secondary energy in a (50:50) proportion of assured energy and of produced secondary energy.

- It is important to point out that the document joined to the Agreement of Market signed by all their agents established that the secondary energy couldn't be allocated in this way. In that document the agents could choice between these two alternatives:

- alternative 1: allocate the secondary energy to all ERM generators in proportion to their assured energy;

- alternative 2: the secondary energy to those who produced it (positive incremental energy).

Here it will be analyzed the implications of that proposal and verified if a better solution doesn't exist.

Alternative 1 shares secondary energy between all ERM participants on the basis of their assured energy. This is the most equitable of the methods, since it reflects the principle of the ERM being a mechanism for sharing hydrological risk. This method uses the symmetry of an over-production situation, relative to total assured energy, to one of under-production. It applies the same principle to a surplus of generation over and above total assured energy as it would to a deficit. In addition this alternative makes the generators indifferent to the dispatch command made by ONS.

Alternative 2 allocates secondary energy to those who produced it. This raises the issue of determining precisely who produced the energy, which is not necessary in alternative 1. While this method creates an incentive to invest in new capacity, in order to retain a higher share of secondary, the incentive to expand capacity may be weakened over time because the long term impact the extra capacity may have on the level of assured energy assigned to a generator. This new capacity would be expected to increase the level of assured energy if it improve water storage capability or prevent spilling. In this situation, new capacity reduces the share of secondary energy allocated over time, since the difference between production and assured energy falls as the level of assured energy rises. The same effect may occur if the interconnection capacity between subsystems with hydrological diversity is strengthened and if the thermal capacity in the system increases (thereby firming the available secondary energy).

MAE proposal, would be a combination of alternatives 1 and 2, in that it allocates the secondary energy in a (50:50) proportion according to assured energy and of those who produced secondary energy. As a combination of alternatives 1 and 2, MAE proposal can be expected to have a combination of the advantages and disadvantages of both, but it fails mainly in addressing the incentives for investment in new capacity by diluting the share of secondary energy allocated to the producing generator. The main problem of this alternative is that the 50:50 ratio is in essence an arbitrary apportionment of the energy; there is no theoretical basis for there being an even split between these groups.

This paper suggest that the alternative 1 should be very helpful in establishing the credibility and transparency of the WEM rules, since the incentives for availability and expansion may be obtained through other mechanisms, such as capacity fees or capacity contracts.

6.3 Surplus Allocation

When the transmission system has congestion between two sub-markets one surplus (constrained on flow times different spot prices) will arises due a different spot prices in these sub-markets.

This question is important because it has been estimated that, assuming persistent transmission constraints, these trading surpluses could be very large in Brazil. Every restructured market with locational prices has faced this issue. It has been subject to considerable debate elsewhere and has wide-ranging implications.

However, the surplus reflects a risk. This is that ERM generators may have energy reallocated to them in another sub-market at price lower than their own. Also MAE members may have pre-existing contracts that span sub-market boundaries, creating a risk exposure. Allocating of the surplus is the means by which this exposure can be managed.

According to the document MAE Rules - General Overview, emitted by ASMAE, in November of 1999, there are four broad options for allocating the surplus. These are to:

- allocate the trading surplus to a fund designed to support future investment in the transmission network;
- allocate the trading surplus to reducing the Transmission Use of System (TuoS) charges;
- allocate the trading surplus by means of Transmission Congestion Contracts (TCCs) or a similar contractual mechanism. These are tradable contracts that will lead to an economic allocation of the trading surplus through parties bidding for the right to receive the surplus. This is an approach followed in a number of the new electricity trading arrangements; or
- allocate the trading surplus to generators who have exposures due to ERM reallocations (where a portion of their assured energy has been allocated in a sub-market with a price lower than their own) and pre-existing contracts with parties in other Sub-Markets.

The MAE is still considering which approach should be adopted in the long term, although one based on TCCs appears a likely choice. However, in order to deal with the particular exposures that will exist when the MAE enters operation, the last option has been agreed as the most appropriated- at least for the duration of the Initial Contracts.

The option chosen in the MAE rules is to use the trading surplus to reduce Initial Contract and ERM exposures, with any additional trading surplus used to reduce TuoS charges.

This approach was chosen because:

- Initial Contracts were not negotiated commercially. Therefore, generators with energy allocated in a Sub-Market other than their own through the ERM would face a risk exposure that is not reflected in the Initial Contract price; and

- some contracts already exist between parties in different sub-markets. It is perceived as unfair to expose these parties to the risk created by introducing a MAE featuring sub-markets with different prices.

Over time, these short-term factors will be less relevant. Initial Contracts will expire by 2005 and will be replaced by commercially negotiated contracts. The prices of these contracts will reflect the risks to which the parties are exposed. Moreover, MAE members will be able to manage inter Sub-Market price risk through TCCs if this approach is adopted. (ASMAE, 1999)

The TCCs option might be the best for the long term. The other options (Fraser et. ali., 1998) are inferior to this solution, namely:

- using the surplus to fund future transmission: this incorrectly aligns the availability of funds for new investment with the value of new transmission. In Argentina, it has led to the problem of over-stimulating new lines in some circumstances and under-stimulating it in others.

- allocating the surplus to generators in exporting sub-markets or D/Rs in importing sub-markets distorts the economic incentives for production, consumption and investment in these sub-markets. Generators receive a price that is a higher than the marginal value of their generation. D/Rs pay a price that is lower than the marginal cost of their consumers' load.

- allocating the surplus just to D/Rs has the same problem.

Creating TCCs would have the key advantage of providing a hedging mechanism for market participants against fluctuations in the prices between sub-markets.

It is important to note that TCCs would not entitle an exclusive right to use the transmission. Instead, TCCs would exist in an environment of open access to the transmission system. The ONS would dispatch the system in a least-cost manner without regard to who holds TCCs, and would calculate the locational prices that result before passing on the trading surpluses to the TCC holders.[13]

For the reasons outlined above, this paper agrees with the MAE proposal for Surplus Allocation.

6.4 Capacity Fee

This is an important question because capacity fees have been proposed for the MAE and these fees would determine a significant source of income to generators, if adopted. The need for capacity fees and the nature of them have been controversial elsewhere. Not all restructured electricity markets have capacity fees and of those that do, no two are the same.

A capacity fee is include in the MAE rules proposal. It is designed to ensure that sufficient capacity is kept available – in the long and short term – to meet peak system demand.

[12] TCC payments are paid irrespective of who uses the transmission system. It is not necessary for the ONS to take TCCs into account in its operation of the system since they are purely financial instruments that are settled outside of the spot market.

A capacity fee is incorporated in the MAE price. It is designed to maintain long term system security. The capacity fee is paid to all generators that have uncontracted availability irrespective of whether this is dispatched or not. This has been judged necessary to ensure that an adequate capacity margin is maintained on the system at all times. (ASMAE, 1999)

The capacity fee has the following characteristics:

- the fee is to be set to recover the fixed costs of plant required to maintain the required level of system security;
- the capacity fee is a function of the loss of load probability (LOLP) which will determined by a model external to the MAE Rules. The more valuable capacity is to the system, the higher will be the LOLP and the capacity fee;
- the capacity fee payment will be split into two components – the first will be paid to all uncontracted generation and the second to all available generation that has not been dispatched. These two elements will have the same value but will be paid on a different basis. The first component will be recovered from uncontracted demand by being added to the MAE price and the second through the system service charge, which will be payable by all demand, whether contracted or not. This reflects the "system service" nature of this non-dispatched capacity, which supports system security.

Capacity fees are not necessary in non-electricity markets. The requirement in electricity markets is based on perceived market failures that would occur if the fees did not exist. These failures can arise from one of three reasons :

- political sensitivity to occasional high energy prices and to large customers reacting to high prices by, for example, cutting factory production;
- a reluctance of some peaking generators to stay available for infrequent occurrences of high energy prices, particularly in dry years;
- A desire to attract more new investment to the market than that which would come from marginal energy price signals alone.[14]

The first reason is a genuine potential market failure in other restructured markets. The consequences of market participants paying or receiving very high prices from the WEM can lead politicians and other stakeholders to conclude that the market is failing. Nevertheless, the solution to this problem is straightforward and is already largely solved in Brazil by the initial contracts, and obligation for ongoing contracts, that are designed into the market. These contracts remove a large portion of the risk otherwise faced by consumers, compared to if their energy purchase costs were derived from market prices alone. To the extent that consumers are not contracted (i.e. their D/R is not contracted on their behalf) they are exposed to potential market price spikes, but the remedy for this problem is for their D/R to sign new contracts on their behalf. A structural solution in the market design is not necessary.

[14] In a market with prices set ex-post, there is a forth reason: the unique speed at which electricity markets clear and a lack of load-control, metering and communication equipment means there may be insufficient information and time for D/Rs to observe high prices and react accordingly.

There is also a genuine concern that some "peaking" generators – that might only run in dry years – might close down, rather than assume the risk of waiting for a dry year to arrive and to receive the resultant (high) prices. It may be efficient for these generators to remain open since they preserve reliability in dry years, and in the long run consumers may be willing to pay the cost of keeping them open. Given the highly volatile revenue stream however, the individual generators may choose to close down, rather than face the risk that the dry year never comes.

The last one, might be the most important. There may be a concern that there could be a reluctance on the part of new generation companies to invest in the Brazilian market, in the initial years following restructuring when the WEM is new and untried.

For the reasons outlined above, this paper suggest more studies about this issue, but It tend to agree with the MAE proposal, that might be important to the Brazilian Electricity Industry to have a capacity in its wholesale market.

6.5 Demand Side Bidding

According to the document MAE Rules - General Overview , emitted by ASMAE, in November , 1999 the MAE's will have a demand side bidding. But the Demand bidders, that have pre-purchased and that are actually dispatched by the ONS would not be credited with the appropriate price for the amount of the load reduction. They only would received a small amount to pay the installations necessary for the ONS real time dispatch.

Demand bids enable purchasers in the WEM to determine how much and at what price they consume electric power. In general, demand bids specify the maximum price at which customers wish to purchase various quantities of power.

Customers with contracts, have reserved enough generating resources to supply their load. They can then either consume this power or sell it back to the MAE in the real-time dispatch. Customers without prior purchases can also participate in demand bidding. In this case, they indicate to the MAE and ONS that they do not want to consume above a particular price, allowing the ONS to curtail their load when this condition is met. Real-time demand bidding involves dispatchable load bids. Dispatchable load is load that is under the direct physical control of the ONS. This will require special equipment and communication facilities between the ONS and the customer.

In this way, in the real-time dispatch the customer's load is treated in the same way as a generator supply source. The ONS will curtail the customer's load when the marginal cost equals the demand bid submitted. (NERA, 1998)

Demand bidding has a number of advantages:

- It enables customers to know, in advance of consuming power, what price they must pay for the power they consume;
- Demand bidding is the most effective way of rationing generation capacity when supply is constrained.

There are some disadvantages to incorporating demand bidding into the market design:

- Dispatchable load bidding requires sophisticated equipment to be installed at customer locations;

- Demand bidding, requires customers to have time-of-use meters (or for distribution customers to have time-of-use meters at the transmission/distribution interface). A monthly meter reading with a total MWh and peak MW measure is not sufficient to ensure that customers pay for what they purchased in different time periods; and

- Dispatchable demand side bidding can be easily gamed, if the market structure does not incorporate both an ex-ante and an ex-post market.

Demand side bidding is required for full efficiency. Short-run efficiency requires demand side bidding, and long run efficiency requires incentives for investments in cost effective price sensitive demand reduction technologies. Technological advances in the next few years will increase the elasticity of short run energy demand by enabling faster responses to price variations. Indeed, most of the efficiency gains in the long run are likely to come on the demand side rather than the supply side. Demand side bidding is essential to obtain these potential efficiency gains. Demand side bidding creates incentives for investing in power management technologies that economize on energy consumption in peak periods. Without demand side bidding these innovations will be stifled. (Cramton&Wilson, 1998).

Market power mitigation is inherently more difficult when demand is treated as inelastic. A key result from experimental studies is that demand side bidding is a powerful instrument in mitigating market power (Bakerman et. Al., 1997). Investments in power management technologies to increase demand elasticity would limit supplier market power. This is likely to be as effective in reducing supplier market power as investments in new generating capacity. Of course, this is possible only if demand side bidding is strongly introduced.

For the reasons outlined above, it is suggested that demand bidders, that have pre-purchased and that are actually dispatched by the ONS must be credited with the appropriate price for the amount of the load reduction. Other demand bidders would be charged only for the amount they consume at the appropriate price.

7 The Government's Role in the new Electricity Industry

The government's role is to establish clear rules for the operation and expansion of a predominantly hydraulic system; to promote competition in generation and commercialization; to regulate the rules of tax readjusts and revisions; to define quality standards and punish companies that do not execute them and to prevent the establishment of companies that detain too much power over the market.

It is fundamental for the government to avoid the capture of the regulating organ, either by the those that should be submitted to it, or by other government organs, responsible for the macroeconomic politics, that could have interest in manipulating the prices of electricity.

Apart from stimulating the competition in generation and commercialization, the government must control the monopolistic activities of transmission and distribution, in the sense of avoiding that the lack of free access in just bases would decrease the intensity of a rivalry in segments where competition is possible.

Acting with the objective of motivating competition, governmental actions should pursue the following objectives: treat market participants in a non discriminatory way; repress the abuse of a dominant position in the market; prohibit the use of crossed subsidies except those approved by ANEEL, limit vertical and horizontal integration; establish the determinative transmission expansion plan and the indicative generation one; guarantee free access to transmission and distribution; separate at least accountably the production, transmission, distribution and commercialization activities; establish a non discriminatory competitive wholesale market and accelerate a decrease of the potency limits for competition in the retail market.

The presence of market power in electricity market without any regulation of prices or profits can cause harmful economical results. The demand for electricity is almost inelastic and even without strong barriers against new entrants it is necessary a long time (more than two years) to build a new production facility.

In these markets with market power, the price is larger and the offered amount is smaller than would prevail if the market was competitive. The basic objective of the regulation, in these cases, is to prevent that anti-competitive practices are adopted.

To avoid market power, ANEEL has already issued Resolution 094/98, where is established some limits to be observed by generation and distribution companies. Each generation company or a group of generation companies with common significant shareholders cannot control more than 20%of total installed capacity of generation in the country. There are regional limits 35% of the North - Northeast Interconnected system (20 % of the interconnected load[15]), and 25 % for the South – Southeast one (80 % of the same one).

The same limits were defined for concentration in distribution business. The attempt of the regulator is to ensure a large enough number of competitors to avoid market power.

[15] The interconnected load is 98 % of Brazilian Electricity one. The remaining 2 % is the share of small isolated system in the amazon region.

8 Conclusion

Over the past decade a number of nations have restructured their electricity industries. Several nations have also significantly reduced the government's role in the ownership and management of domestic electricity industries – both at the state and at national level.

The establishment of a new competitive electricity sector may make possible the expansion of the system using private capital, and can boost the creation of new jobs. The state, free from this obligation, will be able to concentrate resources on social areas. This whole effort is closely aligned to broader social goals, eliminating some of the obstacles to the expansion of the electricity sector.

The breakthrough that made real competition possible on an electricity grid was the concept of an independent system operator and a wholesale energy market that operates a centralized spot market more-or-less integrated with real-time physical operations and open to competitive buyers, while managing all significant unpriced effects as a non-discriminating monopoly. The England and Wales Pool (1990) was the first well-known and widely imitated such system, but many others have been or are being developed around the world.

During the discussion about the Brazilian Wholesale Energy Market (MAE) Rules the following five points were highlighted: pricing and settlement system; energy reallocation mechanism (ERM); surplus allocation; capacity fee and demand side bidding. Due to the importance of these points for a good operation of an electric power market, the same ones were chosen for be approached in this paper.

Nowadays the Wholesale Energy Market has a clear tendency of use one combination of ex-ante and ex-post market for pricing and settlement. These multi-settlement system is used in: Norpool (Norway, Sweden, Denmark), California, New Zealand, Spain, PJM (Pennsylvania, New Jersey and Maryland), New England and New York Power Pool.

For the reasons outlined in this paper, It might be a good idea that the MAE adopt a combination of ex-ante and ex-post markets. The efficiency advantages of the ex-ante market outweigh the drawbacks associated with a more complicated settlement mechanism. An Ex-ante market is best combined with an ex-post market, to prevent gaming of generator availability and demand bids.

The paper shows that should be better recommend that the MAE allocate the secondary energy to all ERM generators in proportion to their assured energy; because this reflects the principle of the ERM being a mechanism for sharing hydrological risk. This method uses the symmetry of an over-production situation, relative to total assured energy, to one of under-production. In addition this alternative makes the generator indifferent to the dispatch command made by ONS.

With respect to the surplus allocation the option chosen in the MAE rules is to use the trading surplus to reduce Initial Contract and ERM exposures, with any additional trading surplus used to reduce TuoS charges.

Over time, these short-term factors will be less relevant. Initial Contracts will expire by 2005 and will be replaced by commercially negotiated contracts. The prices of these contracts will reflect the risks to which the parties are exposed. Moreover, MAE members will be able to manage inter Sub-Market price risk through TCCs if this approach is adopted.

The TCCs option might be the best for the long term. Creating TCCs would have the key advantage of providing a hedging mechanism for market participants against fluctuations in the prices between sub-markets.

It is important to note that TCCs would not entitle an exclusive right to use the transmission. Instead, TCCs would exist in an environment of open access to the transmission system. The ONS would dispatch the system in a least-cost manner without regard to who holds TCCs, and would calculate the locational prices that result before passing on the trading surpluses to the TCC holders.

The need for capacity fees and the nature of them have been controversial elsewhere. Not all restructured electricity markets have capacity fees and of those that do, no two are the same.

Market power mitigation is inherently more difficult when demand is treated as inelastic. A key result from experimental studies is that demand side bidding is a powerful instrument in mitigating market power (Bakerman et. Al., 1997). Investments in power management technologies to increase demand elasticity would limit supplier market power. This is likely to be as effective in reducing supplier market power as investments in new generating capacity. Of course, this is possible only if demand side bidding is strongly introduced.

The international experience suggest that demand bidders, that have pre-purchased and that are actually dispatched by the ONS must be credited with the appropriate price for the difference between the demand pre-purchased and the actual load reduction. Other demand bidders would be charged only for the amount they consume at the appropriate price.

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