TJ. Hammons, P.H. Corredor, A.M. Fonseca, A.C.G. Melo, H. Rudnick, M. Calmet, J. Guerra

Competitive Generation Agreements in Latin American Systems with Significant Hydro Generation

This article is based on a 1999 IEEE PES Winter Meeting panel session on "Competitive Generation Agreements in Latin American Systems with Significant Hydro Generation." The session was sponsored by the IEEE PES Energy Development and Power Generation Committee, and chaired by TJ. Hammons, chair of the International Practices for Energy Development and Power Generation, and chair of the Power Engineering Chapter, UKRI Section; University of Glasgow, Scotland.

During the 1999 IEEE Power Engineering Society Winter Meeting, a panel session on competitive generation agreements in Latin American systems with significant hydro generation was held.

Panelists reflected on deregulation in Latin America, which was started more than 15 years ago. In the region, there is an important contribution from hydro generation with major multiannual reservoirs. These characteristics have required particular arrangements in the deregulation process, on system dispatch, operational planning, pool pricing, and pool organization. These arrangements and how they have worked were discussed. The panelists have been directly involved in pool operation and development of models.

The session was chaired by Thomas J. Hammons, University of Glasgow, United Kingdom, and organized by Hammons, Hugh Rudnick of Catholic University of Chile, and Nelson de Franco of the World Bank. The following presentations are summarized in this article:

- Colombian Electricity Market, by Pablo H. Corredor A. and Adolfo M. Fonseca M. of the National Dispatch Center, Medellin, Colombia
- Competitive Generation Agreements in Latin America Systems with Significant Hydro Generation: the Brazilian Case, by Albert C. Geber de Melo, Coordenador do Programa de Estudos, Economico-Financeiros de Sistemas Electricos, CEPEL, Rio de Janeiro, Brazil
- Competitive Generation Arrangements in Chile: the Governing of the Pool in a Mainly Hydroelectric System, by Hugh Rudnick, Catholic University of Chile, Santiago, Chile
- Peruvian Electric Sector Restructuring, by Mario Calmet and Jaime Guerra, Comite de Operacion Economica del Sistema, Hagler Bailly S. A., Lima, Peru

Colombian Electricity Market

Pablo H. Corredor, Adolfo M. Fonseca

Electricity services in Colombia were provided by government-owned utilities with a small or negligible participation of the private sector and supported financially by multilateral banks like the World Bank and Inter-American Development Bank. National, regional, municipal, or special status utilities were born from regional endeavors and grew up with neither unified vision nor centralized planning for the entire system's development and operation. Vertically integrated utilities provided the electricity services from production to distribution in several isolated regions.

In 1967, the existing utilities joined forces to create Interconexión Eléctrica S.A. (ISA) with the following objectives:

- Interconnecting the regional systems
- Performing integrated expansion and operational planning for the generation and transmission system as a whole.

ISA was formed as a state owned industrial and commercial company under the Ministry of Mines and Energy. Central government and the regional utilities were the former shareholders. ISA became the dominant generation and transmission company with planning and operating functions.

From that time forward, decisions were made based on the minimum cost criteria to meet demand with specific reliability and security levels. However, as the service coverage increased and new and higher investments were required to meet the increasing demand, together with political and regional interests, a number of problems surfaced affecting both cost and service. Incumbent governments set tariffs and made decisions on new investment based on political and macroeconomic criteria instead of efficient resource allocation and full cost recovery. As a consequence, utilities lost their capacity to generate profits and entered into a chronic nonliquidity status that strained the finances of the power sector and, in many utilities, produced a troubling state of insolvency compounded by inefficient management. Many attempts to solve this critical situation were undertaken with no success. These attempts included, among others, management adjustments and infusion of additional financing resources.

Between 1987 and 1990, an Adjustment Program in the power sector was carried out, showing that, for achieving a healthy financial status, structural changes to invigorate the electrical industry were required. In May 1991, through the National Council of Social and Economic Policy, the national government formulated the "Strategy for Restructuring the Power Sector," which was based on the following postulates:

- Energy diversification with increasing gas participation
- Introduction of competition as a means to reach efficiency, a regulatory framework implemented and managed by the National Government, and policies to stimulate private investment.
- Pricing mechanisms of resources based on true economic costs.
- Open access to transmission and distribution networks with regulated charges.

In 1991, a new Political Constitution was enacted. It assigns responsibility to the state to achieve efficiency in the provision of public services. It establishes the competition mechanism, accepts the private agent participation, and strengthens the role of the state as regulator. It assigns to central, departmental and municipal governments the responsibility to ensure the public service provision by their own or through a third party; and it grants citizens the rights to enjoy a healthy environment, whose preservation is also responsibility of the state.

In July 1994, the Colombian Congress passed the Public Service Law and the Electricity Law. The Public Service Law establishes the general principles and policies to govern the provision of Public Services (which include aqueduct, sewage, electricity, cleaning, basin commuted public telephony, mobile rural telephony, and gas fuel distribution) in the country as well as procedures and mechanisms for its regulation, surveillance, and control. The Electricity Law regulates five areas of business in the electricity industry: generation, interconnection, transmission, distribution, and trading. In practice, interconnection is considered a part of the transmission activity.

The following issues reflect the purposes of both laws to solve the structural problems of the Colombian electricity industry:

- Creation of a competitive market as a means to promote efficiency
- Promotion of private participation in order to strengthen competition and to incorporate other sources of capital
- Flexible operating and expansion planning by means of the establishment of indicative planning to guide the decision making process
- Regulation of natural monopolies to prevent the abuse of customers
- Rational rather than political procedures to set tariffs and an efficient subsidy allocation
- Restructuring of utilities to introduce modem and sound management principles
- Granting budgetary, administrative, and financial autonomy to the state owned utilities so that they can operate in a competitive environment
- Surveillance and control of market participants to ensure efficiency, quality, and continuity in the provision of electricity service.

On 1 May 1995, ISA was split into two companies. ISA continued as the transmission company with system and market operating functions, ISAGEN S.A was created as anew generation company. Finally, on 20 July 1995 (Colombian Independence Day), new rules, where competition is the key issue for gaining efficiency, changed the operation and the way of doing business in the Colombian power sector.

Power System Description

The Colombian power system consists of a single interconnected network to supply almost the 99 percent of the total demand. The remaining demand is covered with local generation. In 1998, the peak load was 7,506 MW, a decrease of 0.7 percent from 1997 due to the economic recession that occurred in mid-1997. The energy demand accounted for 44,024 GWh, an increase of only 0.2 percent over 1997. The consumption is split among the different sectors as follows: 44 percent is residential, 24 percent is industrial, 22 percent includes commercial, government-owned entities, lighting, and other consumption.

53.8 percent of the demand is located in the four largest cities (Santafé de Bogota, Medellín, Santiago de Cali, and Barranquilla). Energy losses represented 22.5 percent of total production.

The total installed capacity was 12,057 MW, composed of 67.7 percent hydro and 32.3 percent thermal, plus 240 MW and 33 MW of transfer capacity with Venezuela and Ecuador, respectively. The energy production was 43,933 GWh plus 93 GWh of imports from Venezuela. Local production consisted of 70 percent hydro, 7 percent coal, 23 percent gas, and 0.7 percent from other sources.

Transmission consists of two 230/220 kV networks, the north and the central, linked by two 500 kV lines. The total length of the 230/220 kV networks is about 9,951 km while the 500 kV system has a length of 1,068 km. The average transformation capacity from 230/220 kV to lower levels is about 16,000 MVA and 500 to 230/220 kV is 2550 MVA. The system has 1,997 Mvar of reactive power compensation installed.

Market Participants and Governance

The Electricity Law defines the functions of policymaking, planning, regulation, and operation, as well as the role of entities and agents involved in any business activity (generation, transmission, distribution, and trading) of the electricity industry. Figure 1 shows the relationship between governance entities and the electricity industry.

Policymaking: This is a responsibility of the Ministry of Mines and Energy, who also establishes the criteria for the economic exploitation of conventional and nonconventional energy sources, procuring for an integrated, sustainable, and efficient management and use of the energy resources in the country.

Planning: The purpose is to identify investment requirements in generation capacity for the short and long term, flexible enough so that they can be adapted to current and expected technical, economic, financial, and environmental conditions, and to identify the required investments on transmission in the short and long term, which must be undertaken by investors or by the state. The generation investment plan is not rigid any more, but indicative. In contrast, the transmission investment plan is not indicative, but compulsory. It is a responsibility of the Mining and Energy Planning Unit (UPME) to formulate the investment plans and to promote their execution among government and private investors. But, where no private investors are willing to develop specific projects, the state is responsible for executing the required investments.

By means of an auction process, UPME submits to investors the projects included in the expansion plan for the transmission network. Agents bid for each project submitting the present value of their expected future revenues. The auction will be won by the agent that responds with the lowest present value of revenues (during 25 years) and the best technical proposal to fulfill operating criteria. (Before 1 January 1999, ISA was the only company entitled to build new lines of the STN.) Due to the fact that transmission planning is not guided by market forces but is a centralized process, there can be over or under investments whose overruns are out of customer control, but that must be paid by them anyway.

Regulation: Its objective is to ensure the efficient provision of high quality and low cost electricity service, promoting and setting competition, and regulating those activities where competitive behavior is not possible. Regulation also includes the establishment of the operating and commercial bylaws in order to perform the system and market operation and the indicative operation planning.

Regulation is a responsibility of Energy and Gas Regulatory Commission (CREG), which is a Special Administrative Unit ascribed to the Ministry of Mines and Energy. It has budgetary and administrative autonomy. Its operating costs are covered by all of the agents involved in the electricity industry and who are subject to regulation by CREG.

In July 1995, CREG issued the main body of the Grid Code and Commercial Code. In the following years, a number of rules have been passed to modify or to complement those codes. The Grid Code regulates all aspects of the operation and planning of the National Interconnected System (SIN), while the Commercial Code regulates the issues related to trading activity in the electricity market. The Distribution Code was not passed until 1998.

Surveillance and Control: This is a responsibility of the president of the republic delegated to the superintendent of Public Services (SSPD) and assigned to the Delegate Energy Superintendent. The purpose is to control the efficiency and quality of public services, including electricity services, and to supervise and to control the market participants' behavior. Although SSPD fulfills presidential functions, it is assigned to the Ministry of Economic Development. It has equity and administrative autonomy.

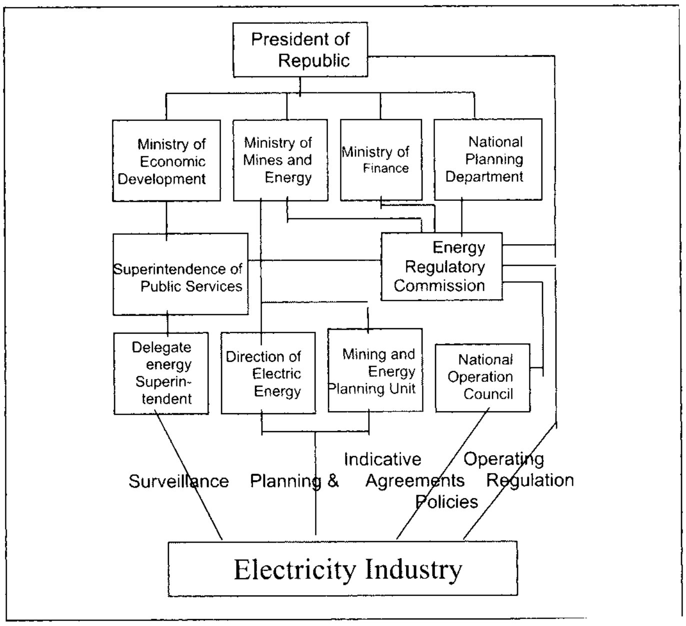

Figure 1. Relationships among the Colombian governance entities and the electricity industry.

System Operation: The National Operation Council (CNO) has been established to ensure the fulfillment of criteria for a safe, reliable and economic operation of SIN. It is the traditional forum for discussion and deliberation on operating and commercial issues. CNO has representatives from each generator connected to SIN, the National Transmission System (STN), the manager of National Dispatch Center (CND), and the distribution network. CNO is supported by several technical committees, subcommittees, and task forces.

Agents are responsible for the operation of their installations, but ISA, by means of CND, is responsible for the coordination, supervision, and control of SIN to ensure its safe, reliable, and economic operation. The functions of system operator are carried out in a hierarchical scheme by CND, four regional dispatch centers (CRD), seven regional coordination centers (RCC), and several distribution control centers (DCC). The CRDs have almost the same technical facilities as the CND, but for regional coverage only. RCCs do not have any control centers.

Through the CND, ISA is also responsible for the indicative operational planning. The purpose of this planning is to forecast the behavior of the system under different scenarios of inflows, fuel, demand, generation and transmission capacity, and resource availability. As a result of the planning process, CND provides economic signals and short-term actions to market participants and government in order to procure a reliable electricity supply for customers.

Again, by means of CND, ISA receives the price offers submitted by generators and performs the generation schedule for the next operating day (initial schedule) and the generation schedule for the next operating hour (final schedule). It assigns capacity reserve for frequency regulation and load following, determines the area transfer limits and reliability must-run generation to preserve quality of service and system security. Also, it administers all of the information related to system operation.

Market Operation: This function deals with the settlement and billing process of all of the transactions carried out in the power exchange. Regulation assigns ISA the responsibility to perform this function, by means of the wholesale energy market area (MEM), another internal business unit of ISA.

Generation: Generation consists of the production of electricity from primary energy sources like hydro, coal, gas, diesel and fuel oil, mainly. It is a fully competitive activity with the greatest and the most dynamic private investor participation in the last three years. From July 1995 to the present, private generators increased from one to 15 and government generators decreased from 16 to 13.

Generators must submit offer prices to the system operator for each of their generating resources having an installed capacity greater than 20 MW. Below.20 MW, offer prices are discretionary. Generators can trade, among themselves, their production in the power exchange and with traders in the long term energy market. But, to trade with nonregulated customers, in the long term, they have to create the trading business activity, either integrated in the same company or separated as another company. Generators are free to participate in any auction opened by traders to provide bilateral contracts for regulated or non-regulated customers.

Transmission: Transmission consists of the transport of bulk power from production centers to customers or to distribution networks, through transmission networks with voltage levels of 220 kV and above. STN is a multiowner network, with ISA holding the largest share. Their participation increased to 80.3 percent last year (1998) with the acquisition of 65 percent of the shares of TRANSELCA, the transmission company that serves the north region. TRANSELCA is the second largest company in the network, owning 7.67 percent of the STN assets. Almost 2.76 percent of the STN is owned by private investors, 88.87 percent by mixed companies and the other 8.37 percent by government-owned companies. From July 1995 to the present, three private transmission companies were formed and the government transmitters decreased from 10 to 9.

New transmission must be an activity separated from generation and trading. Vertically integrated companies, existing before the Electricity Law was passed, were allowed to remain integrated but mandated to have separate accounting for each of their activities.

Due to its monopolistic nature, transmission is a regulated activity. Transmission owners must provide open access to customers on a nondiscriminatory basis, while receiving regulated revenues through the use of transmission system charges. These charges are paid by generators and traders, in proportion to their respective installed capacity and energy demand. Connection to the STN is a competitive business and can be provided by anyone entitled to do it.

Distribution: Consists of the transport of power from either the STN or embedded production centers to end customers using networks with voltage levels below 220 kV. Regulation does not establish any limitation on the integration of distribution, generation and trading, but integrated companies must have separate accounting for each of their activities. Integration between distribution and trading is more common. In the last quarter of 1998, about 30 percent of the market was served with privately owned distribution networks. Distribution is also considered a monopoly and is regulated to provide open access on a nondiscriminatory basis to customers for which they receive regulated revenues.

Trading: Trading consists of purchasing energy in the wholesale energy market, short and long term, and selling it to end users. This business activity was established by the Electricity Law. Traders are the only agents, on the consumption side, allowed to trade energy in the power exchange. Any customer who wants to trade in the power exchange must register as a trader. From July 1995 to the present, private traders increased from 2 to 21 and their market share went, from 5 to 29 percent. Government traders also increased from 32 to 35 during this period, but their market share dropped from 95 to 71 percent.

Customers: Customers are the end users of electricity services. They are classified as regulated and nonregulated customers. Regulated customers buy energy from traders at tariffs regulated by CREG. Nonregulated customers have the following options: buy energy in the power exchange through a trader, buy energy in the power exchange on its own if it registers as a trader, or buy energy in the long-term energy market from any trader or generator by means of bilateral contracts.

A customer is classified as nonregulated if it fulfills one of the following two criteria: has an average installed capacity equal to or greater than 500 kW during the last 6 months, or has an average monthly consumption of 270 MWh in the same period. Beginning 1 January 2000, these parameters will be lowered to 100 kW and 55 MWh, respectively. Regulated customers represent 80 percent of total demand while nonregulated customers account for the other 20 percent. More than 94 percent of regulated and 52 percent of nonregulated customers are presently served by government-owned traders. Private traders serve the rest.

Last year, customer choice was introduced in the market, allowing regulated customers to choose a trader different from the local one. Before 1998, this wa.s not possible because the local trader had a monopoly.

Market Operation

Energy is traded in two competitive markets: the short-term energy market, also called the power exchange (PE), where energy is traded on an hourly basis just for the next day, and the long-term energy market (LTEM) where energy is also traded on an hourly basis but for longer time periods by means of bilateral contracts.

To procure suitable capacity and energy resources availability, the system operator is allowed to use the capacity payment and price intervention mechanisms, respectively.

Power Exchange: Only generators offer prices ($/MW) and declare availability (MW) in this market for each one of their generating resources. Prices and availability are submitted to the system operator for each hour of the operating day. The demand is inflexible, i.e., there is no bid neither from customers nor from traders, and it is taken from a demand forecast which is agreed between the system operator and either regional dispatch centers or regional coordination centers.

Using the offer of prices, the declared availability, the transmission constraints (represented by the area import/export limits, and the reliability must-run generation), regional and local constraints (represented by reliability must-run generation), up and down reserve for AGC, units features, and demand forecast, the system operator computes the optimal schedule for each thermal unit and hydro plants for each hour of the next day, in terms of average MW. This schedule is called the initial schedule, and the loading for each generating resource is called initial generation.

During the operating day, generators are allowed to redeclare the availability of a given generating resource due to its total unavailability. On the other hand, since the system operator is responsible for the system security and for maintaining the frequency inside the accepted ranges (60±0.2 Hz), it is also allowed, at any time, to instruct the start up or shutdown of units, to instruct any out of merit order generation, and to restrict any transfer limit.

The redeclaration of availability, modification of system/regional/local constraints, up/down AGC reserve, price intervention of a hydro plant, and-deviations of demand forecast above 20 MW are accepted up to 1.5 hours before to reschedule the generating resource loading for the next operating hour. This reschedule is called the final schedule, also in terms of average MW, and it must be sent to generators at most a half an hour before the operating hour. The loading of generating resources is called final generation.

Real generation, actual production during real dispatch, of each generating resource at each hour is only known the day after actual Operation. Any difference, between the Real generation and the final generation, greater than 5 percent, that was not required by system operator, is penalized using the penalty rule.

During the operation, CND coordinates, supervises, and controls the operation of the entire system. It can instruct startup and shutdown of units, modify area transfer limits, call up additional AGC reserve, call reserve for load following, etc. The day after the operation, CND validates with agents all of the information resulting from the operation to be used in the settlement process by the market operator and in postanalysis studies by CND. Also, at 08:00 of the day after the operation, CND produces a report, including the main operating variables, which is sent to minister of Mines and Energy as well as to agents.

System Operation

The system Operator uses frequency regulation, load following, and reliability must-run generation as a set of mechanisms to ensure quality and system security.

Frequency Regulation: In order to provide the system with the minimum reserve for AGC system reserve, generators are encouraged to offer capacity (MW) of their respective entitled generating resources, for each hour of the operating day. This offer is called the initial offer of availability for secondary frequency regulation or simply offer of availability for frequency regulation. Based on this offer as well as on the offer of prices for energy, the system operator assigns the AGC system reserve among generating resources from low to high prices. In case of insufficient offer of availability for frequency regulation, the system operator is allowed to call up those entitled generating resources, submitted or not, to meet the AGC system reserve. The entitled hydro plants whose associated reservoir is spilling or those hydro plants under price intervention are excluded from the frequency regulation. The allocation of AGC system reserve among generating resources is done previous to the computation of the initial and final schedules.

AGC system reserve corresponds to the largest generating unit and, at present, it is equal to 230 MW. On the other hand, the entitled generating resources have to meet a set of technical and operating requirements, which have to be validated and certified by the system operator. However, they are excluded from frequency regulation, in case of bad performance, until the respective causes are corrected.

Load Following: This is the service provided by generators, using high-speed generating resources, to keep the production-load balance during the time periods closed to peak hours. At any time period, generators are instructed to follow the final schedule; however. Since this is in terms of average MW, the difference of loading between one and the following hour is normally high for periods around peaks (12:00

and 19:00 hours approximately). Additionally; for those hours the increasing or decreasing of demand has a steep gradient, causing an excess or shortage of power. For instance, over the start of one hour, before peaks, there is a significant excess of power but a significant shortage at the end of that hour. To regulate this unbalance the system operator is enabled to call up additional up arid down reserve. This service normally causes out of merit generation whose overage is allocated among generators and traders in the settlement process.

Reliability Must-Run Generation: This is the generation, in MW or number of units, that must be online at any time to preserve the system stability and voltage levels within acceptable ranges and to compensate for congestion management. This generation normally causes out of merit generation whose overage is allocated among generators and traders in the settlement process.

Authorization: This is the mechanism used by the system operator to call up additional reliability must-run generation or additional reserve for frequency regulation or load following. In addition to technical requirements, the System Operator uses merit order dispatch criteria to call up the required resources.

Short- and Long-Term Reliability: There are two mechanisms to procure system reliability in the short and long term:

capacity payment whose purpose is to procure suitable firm capacity, and price intervention, whose objective is to procure suitable energy resources, mainly hydro, during drought periods.

Penalty Rule: The purpose of this rule is to enforce generators to follow the final schedule so that the system has adequate or minimum reserve for frequency regulation and for load following. The applied penalty at each hour is equal to abs (real generation - final generation)/final generation times abs (offer price - pool price) whenever abs (real generation - final generation) > 5 percent. Deviations caused by instructions of the system operator are not penalized, because they are required for system security or frequency regulation. Rather, they are classified as constrained on or constrained off generation.

Long-Term Market: This is a financial mechanism used by generators, traders, and nonregulated customers to handle the risk of the short-term price volatility. Any two of those market participants can agree, on their own, bilateral contracts specifying prices and quantity of energy to be traded in an hourly basis for a monthly, seasonal, yearly, or any other horizon. Only generators and traders are entitled to register signed contracts to the market operator. This registration is required due to bilateral contracts are included in the settlement process. There is no obligation for physical delivery.

There are no minimum specifications for quantity or time periods. This has allowed market participants to create a variety of contracts. But, in contrast, it has imposed a complex administration to the market operator, due to specific interpretations and continuous changes in the information systems. Also, it has imposed a low dynamic to the market because of limited previous information on characteristics of specific contracts.

Settlement and Billing

The market operator is responsible for the settlement and billing process, which includes data collection and validation, calculation of real demand, ideal schedule, pool price, capacity payments and revenues, penalties, transactions, and reconciliation. Preliminary settlement must be performed during the 3 working days following the operating day. The preliminary settlement for the whole month must be sent to generators and traders within 3 working days after the end of the month. Generators and traders can check and correct possible inconsistencies within the following two working days, and finally, the final settlement and billing must be carried out within the following 5 working days.

Data Collection and Validation: Measurements of production and consumption must be sent to the market operator, within a timeframe of 8 and 16 hours'after the operating day by generators and traders, respectively. The market operator validates and stores this data in a relational database. Traders can send corrections within the following 5 workings days after the month of operation but before the billing process is executed.

In the power exchange, energy is traded at points of the STN. So, any meter located at lower voltage levels or embedded in distribution or regional transmission systems must be reflected at the nearest point of the national transmission system using factors ruled by the CREG.

Real Demand: Real system demand is computed as the summation of the net production of generating resources reflected at the intake points of the STN. The real system demand already includes actual consumption of customers, losses in the distribution and regional transmission networks, nontechnical losses, and losses in the STN. On the other hand, real demand for traders is measured at the outtake points of the STN. This demand does not include losses of the STN, which are allocated among them using predefined factors, ruled by CREG. The basis demand for settlement, called commercial demand, is the real demand plus allocated losses of the STN.

Ideal Schedule: This is a merit order dispatch with no consideration of system constraints. It is computed within the following 2 working days after the operating day based on real system demand, unit features, declared inflexibility, actual availability, and offer prices affected by the price intervention rule. The production of each unit and power plant in the unconstrained dispatch is called the ideal generation, which is supposed to be the production in a pure competitive and ideal market.

Pool Price: The pool price ($/MWh) at each hour is defined as the cost of the last MW dispatched for that hour, in the ideal schedule. At a given hour, all the energy is traded using the pool price for that hour.

Energy Transactions: They correspond to energy traded in the power exchange, computed hour by hour. In general, any Generator or trader sells its excess of supply and buys its excess of demand in the power exchange through the market operator. For traders, the ideal generation is equal to zero. For generators, the ideal commercial demand is equal to zero, except for those having their own consumption. The excess supply is sold and the excess demand is bought in the market, both at the pool price of the corresponding hour.

Reconciliation: The purpose is to identify and to pay for the differences between the ideal schedule and final schedule due to system constraints (reliability must-run generation and constrained on/off generation stemming from frequency regulation, load following and congestion management). The net payments, computed as payments to generators less payments to power exchange, are classified into one global cost and a given set of regional costs of constraints. Global costs are allocated 50 percent to generators in proportion to their installed capacity registered to the market operator and 50 percent to traders in proportion to their hourly commercial demand. Regional costs are fully allocated to agents responsible for removing the corresponding constraint: local distributor, transmission, or connection asset owner. In case of vertical integration between generation and transmission, regional costs are allocated to the transmission business of the integrated company.

Penalties: Generators are instructed by the system operator to operate their generating resources according to the final schedule. But it is normal to find differences between the real dispatch and the final schedule. Differences between the final schedule and the real dispatch due to the system security, load following and frequency regulation handling are already considered in reconciliation. Any other difference between the final generation and real generation is considered to be the generator's responsibility. Penalty is the mechanism used by the market to prevent significant deviations derived from generator actions. Collected hourly payments from generators, due to deviations, are distributed among traders in proportion to their hourly commercial demand.

Capacity Payments and Revenues: Generators are paid the real remunerable capacity (RRC) at US$5.25/KW-month, but have to pay the real equivalent cost of energy (RECE) for each real MWh produced. After the end of each month and for each generating resource, the market operator computes the RRC as the minimum between the theoretical remunerable capacity and the average real availability for the month. Total real remunerable capacity (TRRC) is computed as the summation of the RRC for all generating resources. The total payment to generators is equal to US$5.25/KW - month * TRRC. Each generator receives payments for its entitled generating resources. The RECE is computed as the total payment divided by real system demand for the month. Each generating resource is allocated the amount RECE * real generation. Each generator is charged the corresponding charges of its generating resources.

Achievements

Customer Tariffs: Before 20 July 1995, energy tariffs were regulated, and their computation was based on the average incremental cost of expansion at different voltage levels. For generation, incremental costs included new investments in capacity and fuel costs. At the transmission level, incremental costs included the generation component, the new investments in transmission capacity, and the impact of transmission losses. For distribution, incremental costs included the component at transmission levels plus the component of new investments in distribution depending on the voltage levels plus the impact of distribution losses. In the wholesale market, tariffs covered the full average incremental costs of expansion. But, in many cases, tariffs for customers only covered 80 percent of the incremental costs. In other words, customers received a subsidy from utilities.

Since 20 July 1995, energy has been traded in the power exchange at hourly pool prices and in the bilateral contracts at prices agreed between the two parties. Each bilateral contract has its own prices. Transmission and distribution services have been unbundled and paid by means of the use of the system charges that have been regulated by CREG. Connection charges also are agreed between the user and the service provider. Running costs of SSPD, CREG, CND, CRDs, and MEM are also covered by agents.

Pricing for the regulated market is based on the aggregate reference costs from production centers to the supply points of each customer. These costs are computed for each trader, in each month, for each standardized voltage level and each electrical zone. They include energy costs, "use of the transmission system" charges for the corresponding electrical zone, "use of the distribution system" charges for the corresponding voltage level, trading costs, costs of running the wholesale market, and cumulative losses for the corresponding voltage level.

Important issues to point out are:

- Tariffs setting is based on market mechanisms for the wholesale nonregulated market and on the pass-through costs basis for the regulated market
- Tariffs for regulated market include market signals through the costs of purchase made by each trader in the wholesale market as well as through the average prices for the entire wholesale electricity market
- Subsidies are allocated to low incomes customers and covered, in some extent, by high incomes customers, industrial and commercial sector
- Regulated customers can choose the trader that provides the best quality and low cost service.

Pool and Bilateral Contract Price: Pool price in Colombia has shown a high volatility since July 1995, ranging from US$0.009/kWh to $0.095/kWh. Many factors affect this volatility, but inflows have proved to be the most relevant one. In contrast, bilateral contracts prices have been quite stable during the same period. However, the average pool price up to November 1998 was US$0.026/kWh, 15.3 percent higher than the average bilateral contract price for the same period. In 1994, the price of energy in the wholesale market was about $0.039/kWh (present value). Currently, tariffs for the regulated market have the following composition: 45 percent generation, 5 percent transmission, 38 percent distribution, 9 percent trading, and 3 percent for other costs.

Private Investment: Before July 1995, there was only one private generator with an installed capacity of 90 MW. Other utilities were fully government-owned. At the end of 1998, there were 15 private generators, 21 private traders and 6 transmission companies, with almost 92 percent of the STN fully or partially privately owned. ISA, a state owned company, now has 7.5 percent private ownership. During 1999, the government expects to privatize another generator, the rest of its distribution companies and to sell a significant portion of its participation in ISA.

Entrepreneurial Efficiency: Two of the most relevant indicators that reflect inefficiency in many state owned utilities are the continuous provision of capital and the current overdue amount with service providers. In 1997, the government provided about $36 million to cover the losses of its companies. In October of 1998, the debt of these utilities with other agents reached $294 million. However, with the privatization of eight utilities at the north coast during the second semester, this debt decreased as much as $93 million by the end of the year.

One result has to do with unit availability. The new business orientation has changed some maintenance practices, resulting in an increment on availability indices. For instance, while the average availability for thermal capacity was 69 percent in 1994, it was around 73 percent in 1998, with a December peak of 85 percent, the largest in the last 10 years. In 1992 and 1993, when the country was affected by an energy shortage, the average thermal availability was only 67 percent; nevertheless there was an opportunity to get good financial results. Some generators have re-powered their generating units at a very low cost per MW, and there is a significant trend to re-power small generating units, mainly hydro, abandoned years ago.

State as Regulator: Since the Public Service and Electricity Laws passed in 1994, the state, through the CREG, has strengthened its role as the regulator of the electricity and gas sectors. The 672 rules issued by CREG, since 1994 shows the dynamic of this role. New rules have been implemented to adjust and promote competition in the market. Adjustments have been introduced, for instance, in the allocation of reconciliation costs, price intervention rule, causes for rescheduling the initial schedule, introduction of customer choice, introduction of competition in the expansion of STN, changes in capacity payments, procedure for setting tariffs of regulated customers, reserve for frequency regulation, curtailment and pricing procedures during shortages, among others.

Quality and Reliability of Service: Although planning and operating criteria existed before, the responsibility of service providers to fulfill them was not clear. Now, customers have duties but also have rights that enable them to make claims to providers not meeting the quality and reliability criteria established in 1995 for system planning and operation and in 1998 for distribution. On the other hand, due to the high dependence of the Colombian power system on hydro resources (79 percent at the end of 1995 and 68 percent at the end of 1998), and to the impact of the El Nino phenomenon on inflows, the country has been subject to energy shortages every three to five years. From March 1992 to April 1993, inflows decreased more than 64 percent of the historical average, causing a demand shortage of almost 16 percent of the total energy supply. During the second semester of 1997 and first quarter of 1998, El Nino affected inflows again, causing the strongest droughts during the last 50 years, but for a shorter period. However, the country was better prepared to manage the effects with less dependence on hydro resources, reducing the vulnerability of the supply to El Nino. The combined efforts of the government, CND, generators, the gas and oil industry and ISA avoided another reduction of energy supply in the country.

Challenges

Market Mechanisms: The Public Services and Electricity Bills introduced the need for free competition (and if possible, perfect competition), as a necessary condition for gaining efficiency in the resource allocation process that will reflect, as expected, a reduction of customer tariffs, in real terms. Governance entities are conscious of this, however, the introduction of market mechanisms for trading electricity has been timid.

Competition was introduced for the first time in 1995 on the supply side, by means of the offer of prices of generators (but not availability, that has to be declared) to trade energy in the power exchange. However, the introduction of bidding in the demand side is still pending. Even more, up until now, Offer Prices for the next operating day are used for the next operating hour and also to allocate AGC system reserve among generating resources.

During operation, load following requires additional reserves to be is called up by the system operator. On the other hand, deviations of real generation from final generation are based on a penalty mechanism instead of using a flexible market mechanism. Generators argue for mechanisms to optimize the use of their resources in the very short term and in real time operation.

In addition to transfer limits, congestion is managed by means of reliability must-run generation which is computed by the system operator. In some cases there is only one provider of this generation, configuring a dominant position that benefits the corresponding generator. Generators and traders who usually pay for the congestion costs are encouraging the CREG to introduce mechanisms to remove congestion or at least to address the right signal to the right agents.

In bilateral contracts for nonregulated market, parties are free to agree on prices and quantities, but there is not any simultaneous concurrency of generators and traders in the market. In the case of regulated market, traders are mandated by regulation to contract at least the percentage of regulated customer demand established for the corresponding year. Market participant would like to have new products including standardized physical and financial instruments administrated by a clearinghouse.

There has been a substantial advance in customer choices from 1997, but the absence of flexible procedures and low costs technology for metering has limited the dynamic of this option.

Starting on 1 January 1999 competition to build new transmission assets is expected to encourage a cost reduction in transmission and so a reduction in use of transmission system charges. The challenge consists on setting and strengthening this mechanism in transmission and on introducing a similar one in distribution.

In general, CREG has big challenges to take advantage of market forces to benefit market participants in terms of best quality and low cost services for customers and more transparency and profitability for service suppliers.

Financial Instruments: Although bilateral contracts already exist as a financial instrument, market participants claim for new financial products under more transparent conditions. But first, CREG must strengthen the physical market through power exchange, establish an independent clearinghouse and create the conditions for a truly liquid and deep market. This must be associated with the strengthening of current

Colombian financial markets. Currently, the Ministry of Mines and Energy is starting a study whose objectives are to yield recommendations on how to separate the market operation functions from ISA and how to set financial instruments in the energy market.

Andean Power Exchange: Bolivia, Colombia, Ecuador, Peru, and Venezuela are the Andean countries. Through the Andean Community of Nations (CAN) they have already integrated trading of manufactured products. Also, in recent years, local investment groups have extended their businesses into other countries. In the same fashion, the electricity industry is considering the integration of power systems to open frontiers to a common power exchange. During 1997 and 1998, the Electric Commission for Regional Integration (CIER) completed a study of South American countries to identify integration opportunities. In 1992, Colombia and Venezuela commissioned a 230 kV line with transfer capacity currently at 240 MW. In 1998, Colombia and Ecuador commissioned a 115/138 kV line with transfer capacity of 33 MW and a stronger interconnection is under study. There is no interconnection between Peru and Ecuador, Bolivia or Colombia. Implementing the Andean exchange will require the development of physical routes to transport energy and the rules and protocols to govern this market.

Overdue Accounts: One of the problems derived from inefficient management and low financial resource generation, is the low capability of some utilities to cover their financial obligations. The challenge for the government is to successfully conclude the privatization process started in 1996.

Conclusions

Deregulation of electricity market in Colombia has shown to be a successful process in terms of its initial objectives. The formulated goals of the restructuring process have been achieved to a great extent so far. Average price of bilateral contracts has remained stable and below the former tariffs of energy in the wholesale energy market. Although average pool price has shown to be highly volatile, it has also been below former tariffs. Private participation has increased substantially and the inefficient management of government-owned utilities, mainly distribution, is improving with the influx of private investors.

Thus far, there are a great number of visible achievements, but there are still many challenges to be met in order to strengthen market mechanisms in the decision making process in the Colombian electricity industry. Although there is a long and a hard way to run, it is clear that nobody wants to go back. Government entities, especially CREG, have a big challenge for the future, i.e., to strengthen and to develop market mechanisms that benefit both customers and investors.

About the Panelists

Pablo H. Corrector was born in Colombia. He graduated as an electrical engineer in 1977 from the Colombian National University, Bogota. He obtained his MSc degree in power systems in 1983 from UMIST, United Kingdom. He has been working in the area of expansion and operational planning of power systems. National Dispatch Center since 1977. His current position is manager. National Dispatch Center, Interconexion Electrica S.A. ESP-ISA.

Adolfo M. Fonseca was born in Colombia. He has been an electrical engineer at the Technical University of Pereira (Universidad Technologica de Pereira) since 1980. He obtained his MSc degree in operational research in 1988 from the University of Southampton, United Kingdom. Prior to this, he was a lecturer at the Bolivarian Pontifical University, Colombia, from 1980 to 1983, until he started work for ISA in the area of operation and expansion planning. Currently, he is a business management specialist at the National Dispatch Center, Interconexion Electrica S. A. ESP-ISA.

The Brazilian Case

A.C.G. Melo

Brazil has a population of 160 million inhabitants, a land area slightly smaller than the United States, and economic output of nearly US$800 billion, half of the Latin American economic output. The industry output is responsible for 37 percent of the GDP, indicating its maturity level. The Brazilian economy is integrated in a regional trade zone (Mercosul) with Argentina, Uruguay, and Paraguay, with the objective to increase the competitiveness of the regional economies.

Since 1990, Brazil has been committed to an ambitious national privatization program to be completed by the end of 1999. This program is part of the Brazilian effort to attract private and foreign investments in the infrastructure sector concentrating the state actions in areas as education and health. One of the measures to show the opportunity for private investment in the infrastructure area is the difference between the financial requirement for the present year (more than US$40 billion) and the public sector expenditures in new infrastructure projects (US$20 billion). For example, the power sector will require US$8 billion per year for new investments in the next 4 years, while the internal sector financing capability is approximately half of this value.

Privatization of existing assets at both the federal and state levels is underway. From 1995 to 1998, several large distribution companies have been sold to local and foreign investors. As a consequence, 51 percent of the distribution market is now owned by private agents. The total revenue was US$22 billion. The privatization program of the distribution companies is expected to be completed in 1999, when 81 percent of this market will comprise private companies [1].

At the generation level, the assets of Eletrosul (3,600 MW) and the Cachoeira Dourada hydroplant (700 MW) were privatized. The federal generation assets (Eletronorte, 5,500 MW;
Furnas, 7,500 MW; CHESF, 10,700 MW), and the generation assets of CESP (10,500 MW) are expected to be privatized in 1999/2000. This would lead to a private market share in the generation segment higher than 82 percent.

System Characteristics

The Brazilian power system is composed of two large interconnected systems. The first corresponds to the South, Southeast, and Middle-West Regions (SSE) and the second, to the Northeast and part of the North Region (NNE). Since December 1998, a 500 kV, 1,000 MW, 1,000 km is interconnecting these two systems.

The system is hydro dominated (more than 90 percent of the installed capacity) and characterized by large reservoirs presenting multiyear regulation capability, arranged in complex cascades over several river basins, including the world's largest hydroplant, Itaipu, with 12,600 MW installed capacity and jointly owned by Paraguay. There are also isolated electric systems of varying sizes, mostly located in the North region. Some of those isolated systems are of significant size, as they supply state capitals.

Hydropower is expected to remain the dominant source of electric power as the country adds capacity to meet demand, but it is expected to increase the participation of thermal plants in the system in view of the advances in gas turbine technology and the exhaustion of hydro resources.

Load growth rates in Brazil have been historically high, mostly due to the country's industrialization effort. In the 1970s, average growth rates were 9 percent. Even with the economic recession of the late 1980s and early 1990s, growth rates averaged 4 percent. In 1997, firm load increase was around 6 percent. Forecasts made by the Coordinating Group for System Planning (GCPS) indicate an average growth around 5.1 percent, for the next 10 years [2].

Brazilian Restructuring Process

The objectives in implementing a new institutional and regulatory framework in Brazil are to:

- Ensure a secure and reliable supply of electricity
- Encourage economic efficiency in all segments of the sector, notably through the maximization of competition (where feasible), the design of appropriate regulatory arrangements and the continuity of the relevant system inte-grative functions
- Support the further development of economic hydroelectric sites
- Create conditions that support the continuation of the privatization program and make new investments attractive to the private sector, in particular through appropriate allocation of risks.

In the new trading model for the Brazilian electricity sector, there will be a wholesale energy market (WEM) in which all buyers and sellers of electricity can trade and in which the spot price of energy will be determined. The WEM will be created by a multilateral agreement which is compulsory for all generators with installed capacity greater 50 MW and for all distribution and retail companies with consumption grater than 100 GWh per annum. Large consumers with demand above the threshold for the free market (currently 10 MW) can choose to become WEM members.

The main objectives of the WEM are to [3]:

• Set a price that reflects, in each time period, the marginal cost of energy on the system (this price will support the long term bilateral contracts.)
• Provide a marketplace in which generators and retailers can trade their uncontracted energy
• Create a multilateral environment to support the development of competition under which a retailer may buy from any generator and a generator may sell to any retailer.

In such environment, there will be competition in the generation and commercialization segments, while the transmission and distribution segments will remain as natural monopolies, subject to regulated tariffs. The competition among the generation companies will be associated to the establishment of bilateral long term contracts with the loads. The bilateral contracts are financial instruments which will specify a contract price for a fixed volume of energy. In other words, the generators will receive a negotiated payment from loads and, in exchange, become responsible for their spot tariffs. These bilateral contracts will reduce the exposure to the spot prices.

The trading arrangements will be based around a tight, centralized system optimization, scheduling and dispatch scheme. In this approach hydro and thermal generators submit only technical data on their plant, such as water levels in the reservoirs, rate of inflow, technical availability of the turbines, thermal efficiency, fuel and operating cost data, etc. Therefore, there will be no price bidding scheme.

There will be an independent system operator (ONS) that is responsible for central system optimization and dispatch according to clearly defined rules agreed by all industry members and approved by the regulatory body (ANEEL).

Based on the received technical data, the ONS will establish a generation schedule which describes which generation plants should be dispatched and the associated generation target in order to achieve least cost operation of the whole system. This schedule will be obtained through a chain of optimization models which will also calculate the water values. The water values will form the basis for determining the WEM price in each period.

Generators and retailers will continue to trade most of their energy via bilateral contracts. These contracts will originate payments from retailers to generators. The price and volume of energy specified in the bilateral contracts will determine the size of such payments.

After deduction of the sales and purchases covered by bilateral contracts, the net requirements of generators and retailers will be traded in the WEM thus being subject to the WEM price.

It is important to observe that all energy flows will be taken into account in determining the optimal generation schedule, dispatch and the WEM price. However, only the uncontracted energy flows would be subject to the WEM price.

To determine the WEM price, only the major transmission constraints will be taken into account. Therefore, the Brazilian interconnected system will be divided into a small number of regions denoted as submarkets, which will reflect the effects of these more important transmission limitations. The WEM price will be determined for each submarket and transmission loss allocation factors will be used to calculate the final price for each generator and load inside each submarket.

Generators and loads will also pay a yearly fixed transmission use of the system charge ($/installed kW for generators and $/yearly peak for loads), which depends on their location. This tariff does not depend on bilateral contracts, i.e., there are no wheeling rates.

Commercialization Risks and Possible Mitigation Mechanisms

In most restructured power industries, the clearing price for energy purchasing and sale is the short run marginal cost (SRMC). However the application of SRMC in hydrothermal systems have some difficulties due the characteristics of those systems.

Predominantly hydro systems are designed to ensure load supply under adverse hydrological conditions, which occur very infrequently. As a consequence, most of the time there are temporary energy surpluses, which imply very low system short-run marginal costs.

In turn, if a very dry period occurs, SRMCs may increase sharply, and even reach the system rationing cost. Due to reservoir storage capacity, these low-cost periods not only occur frequently but can last for several years, separated by higher-cost periods, caused by droughts.

This pattern is illustrated in Figure 2 [4], which shows the observed hydro marginal costs in the Brazilian south-southeast system from January 1993 until August 1997. Figure 2 shows that the system SRMC was close to zero in 36 out the 56 months, and the longest wet period lasted for 21 months.

This punctuated price evolution results in a very skewed price distribution in each stage. For example. Figure 3 shows the forecasted SRMC frequency distribution for the Brazilian Southeasthem System calculated for March 2001 [5]. Out of the 2000 simulated hydro scenarios, there are 65 percent with marginal costs less than $5/MWh, and another 26 percent with costs ranging from $5/MWh to $50/MWh. In contrast, there are a few scenarios in which the SRMC exceeds $300/MWh.

Looking at the SRMC distribution, we can observe that thermal plants in the low-SRMC scenarios, which are the most likely scenarios, have zero revenue. On the other hand, in the high SRMC scenarios, the thermal plants have very high revenues, but this event is very infrequent. In turn, hydro plants have an assured revenue in low-SRMC periods (but a low revenue) and have a strong interest in avoiding exposure to the high-SRMC situations.

A possible way of reducing this price exposure is to use electricity derivatives, i.e. financial instruments which enable an investor to systematically decrease the amount or kind of risk he accepts. For example, the a popular derivative instrument is the so-called "contract for difference" (CFD). Additionally, it is easy to conceive a hedging scheme between hydro and thermal plants: the hydro generator agrees to pay in advance the thermal plant's fixed and variable costs, in exchange for its energy in the high-SRMC periods.

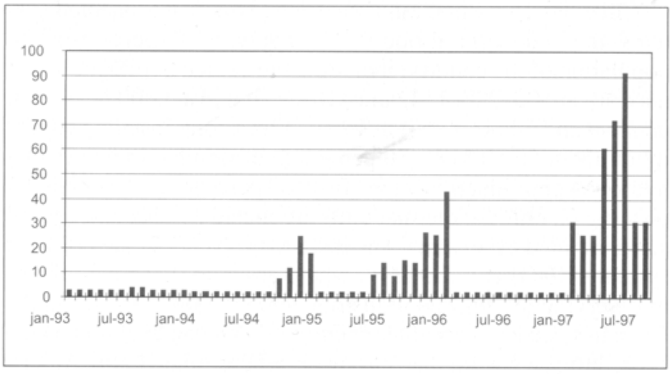

Figure 2. Historical monthly short-run marginal costs for the Brazilian system

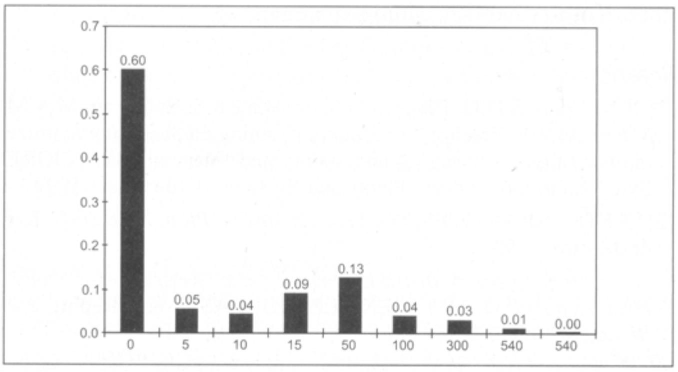

Figure 3. SRMC distribution, March 2001.

However, observe that the price pattern in hydro-dominated systems has two consequences: because spot prices are very low most of time, customers are tempted to "play the odds" and not sign long-term contracts; because severe droughts can increase the system marginal price to very high levels for several months in a country-wide basis, financial agents such as brokers and insurers do not have the financial capability to pay contracts for difference.

The first problem can be handled through compulsory contracting schemes for most of the customer loads. In Brazil, it is envisaged that 85 percent of system load should be long-term contracted (bilateral contracts). The second problem can be handled through two schemes: (cross-contracting between hydro and thermal generating agents; force majeure regulatory schemes such as a cap on system spot price or automatic relaxation of contracts in case of a severe drought.

Another way to manage the hydrological risk faced by hydro plants as well as to alleviate pricing distortions for plants in cascade with distinct ownership is to establish a multilateral energy reallocation mechanism (ERM) [3]. The ERM would ensure that, under normal operating conditions, hydro generators would receive the income proportional to an energy credit, which is proportion to its contribution to the system firm supply capability, which is the maximum load that can be supplied by the hydro system with a given level of reliability. The energy credit is calculated as the difference between system firm capability with and without each hydro plant and reservoir individually In other words, individual hydro generations at each stage are summed and the total hydro production is reassigned as energy credits for each hydro plant; this assigned credit is then compared with the plant contract, and compensated on the basis of the system spot price.

Finally, the emerging competitive environment in power sectors requires the development of new methodologies and computer programs. In particular, hydrothermal systems need powerful computer programs to calculate generators' risk exposure and to define optimal contract portfolios, i.e., the optimal level of long term and short term contracts that a generation or distribution company should enter. These new tools will be very important to establish trading strategies.

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About the Panelist

Albert C. Geber de Melo was born in Manaus, Brazil. He received his BSc from the Federal University of Pemambuco in 1983, and the MSc and DSc degrees from the Catholic University of Rio de Janeiro (PUC/RJ) in 1986 and 1990 respectively, all in electrical engineering. Since 1985, he has been with CEPEL, the Brazilian Electric Power Research Center, working on the coordination and development of projects and software in the areas of power system reliability, transmission planning and pricing, marginal costs evaluation, efficient cost allocation methods, economic and financial evaluation of projects including risk analysis. He is currently head of the Power Systems Economics and Financial Studies Research Program at CEPEL. He is also an associate professor at the State University of Rio de Janeiro. He is an active member of IEEE, CIGRE, and several Brazilian working groups. He has been deeply involved in the Brazilian power sector restructuring process.

Competitive Generation Arrangements in Chile

Hugh Rudnick

A 1997 World Bank report defines several conditions that a pool must fulfill to contribute to the development of competitive generation markets. Among these conditions are pool not controlled by one agent or class of agents, nondiscriminatory market, transparent decision making, reliable operation in agreement with quality standards, pool structure, and rules may be improved as needed.

The recent operation of the Chilean pool and the increasing problems in its governance, in face of a severe drought period in a mostly hydroelectric system, has clearly demonstrated that the pool does not fulfill these conditions and that changes must be implemented for the competitive market to continue developing. This presentation describes the main Chilean market, concepts utilized in the design of the pool, relevance of the hydroelectric dimension in the Chilean system, problems faced in the pool over the last 2 years, and the solutions being implemented.

Chile has 15 million inhabitants and two interconnected systems, the main central one (SIC) supplying 93 percent of the population of the country, including the capital Santiago, with a network at 500, 220,154, and 110 kV. It had a 3,800 MW peak demand and 24,000 GWh in 1997. With a total installed capacity of about 5,250 MW (70 percent hydro) in the main system, hydropower production varies from 60 percent to 90 percent depending on rainfall; thermal units are fueled by coal and natural gas combined cycle units. The installed capacity of the northern system (SING) is 1,270 MW, where around 99 percent is thermal, serving mining and industrial demand. More details on the Chilean systems, companies and regulations can be found on the Web, http://www.ing.puc.cl/power, where other Latin American deregulation models are also described.

Plant Ownership, Market Power, and Cross Ownership

The Chilean power deregulation process was a worldwide pioneer and had no other references on which to rely for market design. One of the areas in which this is clear was in the lack of restrictions on market control and plant concentration. Although the privatization process aimed at avoiding cross ownership, selling separately the distribution and generation businesses, no legal restrictions were put in place, and concentration of ownership developed. In the SIC, there are three main groups controlling generation. The Endesa holding, a hydro-based one, has 56 percent of the installed capacity (1997), with its Endesa, Pangue and Pehuenche companies. Gener, a thermal-based holding, controls 27 percent with its Gener, Guacolda, and Electrica Santiago companies. Finally, Colbun, hydro-based, owns 10 percent of the generation capacity. The future interconnection between the hydro-based central SIC system and the thermal-based northern SING system will not change this concentration of ownership. Cross ownership is also present, with the Endesa holding owning most of the transmission system. Finally, vertical integration is present with a larger holding, Enersis, controlling the Santiago distribution company Chilectra and being the largest shareholder in the Endesa holding.

A ruling by the Antimonopolies Commission determined that the cross-ownership and vertical integration had not given place to actions of market power, and that regulations in place were sufficient. Nevertheless, it requested changes in ownership, with a separation of the transmission company, as well as public processes for distribution supply contracts. It is interesting to note that vertical integration is not necessarily seen as attractive by all involved in the business. The board of the Enersis holding decided at the end of 1998 to sell its shares in Endesa, although this decision is being disputed by other main shareholders.

Design of the Pool

The Chilean market model, unlike the models recently implemented in California, assumes that a central dispatch is needed to clear the market, thus playing the Adam Smith role. According to the law, companies engaged in the generation of electricity in Chile must coordinate their operations, through one autonomous entity integrated by the principal generating companies for each interconnected network, known as Economic Load Dispatch Center (CDEC). The CDEC, as an independent operator, plans and coordinates the operation of the plants to ensure secure and economic efficiency in the electricity system, irrespective of ownership. Demand is therefore met by dispatching the available plants according to their variable production costs, from lowest to highest, and is thus always done at the minimum attainable cost. The assumption behind this is that with perfect competition, prices would be optimal marginal costs.

Another assumption in the regulatory design was that pool governance was to be better achieved by full agreement among all participants. Therefore, the law indicates that agreements in each CDEC are to be achieved unanimously; otherwise, the Ministry of the Economy intervenes to solve divergences. Some agents see this as the means to control market power by the main holdings.

Generation companies meet their contractual sales requirements with dispatched electricity, whether produced by them or purchased from other generators in the spot market. Therefore, they sell to the following three markets:

- Spot market, which includes energy transactions between generating companies, from those able to generate more than their contractual commitments according to the optimal operation of the system (surplus companies) to those with production levels below their commitments (deficit companies). Transfers are determined by the CDEC using dispatch models and are valued hourly at the system's marginal cost of operation, also determined by the CDEC. The energy spot price varies depending on the existing hydro-logical condition, the water availability, the plant location, etc. Besides, capacity spot prices are determined considering the cost of developing peak capacity.

- Unregulated market, which is made up of consumers with a connected capacity of over 2 MW, normally industrial or mining companies. These are customers who are not subject to price regulation and able to freely negotiate electricity supply prices with generating or distribution companies. They do not have access to the spot market.
- Regulated market, which is constituted by consumers whose demand is 2 MW or less, usually located within a distribution company's concession area (typically residential, commercial, small and medium industrial customers). Sales of generating companies in this market are made to the distribution companies, under regulated prices determined by the Ministry of the Economy. To ensure price stability, the National Energy Commission (NEC) sets regulated prices for 6-month periods, based on projected marginal costs in the system. These prices somehow provide a hedging mechanism for generators signing contracts with distribution companies. These companies do not have access to the spot market either.

Relevance of Hydroelectricity

The regulatory design in electric markets with high hydro-logical contribution provides challenges that are different to the markets in which thermal generation dominates. This has made several countries rely on cost-based spot prices pool schemes rather than bid-based arrangements. Argentina, Chile, Bolivia, and Peru implemented cost-based schemes, with Brazil following the same path. Argentina relaxed the scheme, allowing bids around marginal cost. Only Colombia chose an open bid-based scheme, but it soon faced difficulties with dominant hydro generators that had to be intervened.

As indicated, Chilean regulations require that the operation of each interconnected system aims at supplying the demand at a minimum cost, taking into account security and quality of supply and environmental conditions. For this purpose, dispatch models are to be used by the CDEC in charge of each system. A single bus multireservoir model called OMSIC is used in the SIC. It works with dynamic programming and considers a single bus load. Fundamentally, this model optimizes extractions to the main reservoir, the Laja Lake, that has the largest regulation capacity in the system, in order to minimize the thermoelectric generation and non-served load expected cost during the whole planning horizon. Other less significant hydro resources are incorporated at a later stage. In this model, hydrology is considered independent between the winter months (April-September) and dependent in the summer time (October-March, melting months). Decisions are made based on a random-decision mode. The model considers two stages, optimization and simulation. In the optimization phase, the objective is to minimize present and future costs using dynamic programming. In the phase of simulation, the model uses the Montecarlo method. The output of the model is a table of expected marginal costs, a table with the expected reservoir levels for Lake Laja and the expected generation by each power station. Convergence iteration is added afterwards, where other hydroplants are taken into account. Lake Laja marginal costs are provided as reference to these plants, and transfers of hydro generated energies between plants are determined.

The controlled use of water through the year is very relevant in the SIC, where energy restrictions are the norm rather that capacity ones. Demand increases at the time water reservoir inflows decrease. With yearly demand growth rates between 7 to 9 percent, main increases arise in March, when the country holiday period ends and the school year starts, and in July, when the winter consumption increases. The contrary takes place with water inflows, with an important reduction between January and April. Historical inflows usually follow three seasons. A rainy season extending from April to September, with inflows increasing in April/May, with a maximum with winter rainy storms in June/July, to decay in August. A second season between September and December, where the snow in the Andes melt, with water inflows growing rapidly towards November, starting to reduce in December. The dry season starts in January, with a drastic reduction of inflows through February, March and the beginning of April. Inverse processes take place in March/April; demand increases with water inflow reductions.

Extreme Hydroelectric Conditions Test the Pool Model

Emergency conditions with severe droughts in Latin America are testing the regulatory models, particularly in countries by the Pacific Ocean where the El Nino phenomena has stricken strongly. This has been dramatic in the Chilean case, where a critical supply condition arose in the SIC at the end of 1998 and beginning of 1999. Water inflows remained constant and low throughout the hydrological year, with almost no rainy season and only minor increases between October and November, due to melting of high mountain icecaps. A similar situation arose 20 years earlier in 1968-1969, but the country was at a minor stage of economic development, and it had no significant impact. Instead, the recent situation led to damaging rotating blackouts in November of 1998 and April of 1999. In what is the most severe drought of the century, supply was endangered by the unreliable start on new combined cycle natural gas turbines (CCGT) due to be commissioned in early 1998.

The uncertainty of water inflows, the high investment required for hydro plants, and the limited local energy resources in the country, combined with the low cost availability of natural gas in neighboring Argentina, led private investors in Chile to build several gas pipelines across the Andes to feed new power plants and industrial consumers. A new combined cycle plant in Santiago started in 1997, with two more due to start in 1998. One of them, Nehuenco, was due to start by March, which led the CDEC to plan water use accordingly. The plant commissioning was repeatedly postponed, and, finally, it only started at the end of the year. To worsen things, both new combined cycle plants proved more unreliable than expected. The CDEC was faced with a condition in which it had used most of its water reserves, and there was no thermal backup on which to rely. Disagreements among CDEC participants on how to face the emergency grew every day. Deficit generators were faced with extremely high prices. Accusations were made among participants on breaking of generation commitments; some were charged of looking after their commercial interests rather than system security.

The government had to intervene on two fronts: looking after society interests confronted with frequent blackouts, and its legal responsibility to make decisions when CDEC participants did not agree unanimously. The pool model, CDEC, had started operating in the SIC with a specific bylaw enacted in 1985. It operated well over 10 years, with competition taking place on cost of supply (efficiencies were increased by generators, new technologies like CCGT were introduced) and on commercial actions (contract portfolios). However, as the extreme drought conditions damaged hydro businesses, as competition increased and prices decreased with the arrival of natural gas, unanimous agreements became the exception. Even reliability was endangered by the disagreements and fines had to be applied to participants given some unexpected blackouts in 1998.

Disagreements in the CDEC arose on the determination of hydrothermal spot prices, on capacity payments, on the hydro-thermal coordination dispatch models, on transmission modeling and on operation security Strategies, as each matter has an incidence on marginal prices and company income.

Questioning of Price Regulations

One of the sources of disagreement lies deeply in the price system defined by the law, both in the calculation of spot prices and regulated prices for small consumers. As indicated earlier, energy transactions between generating companies take place in the spot market. The price for those transactions is the instantaneous spot price, as determined by the CDEC. In a cost-based scheme with hydrogeneration usually dominant, hydrothermal dispatch models are required to determine which is the spot price when a generator in a reservoir acts as the marginal unit. While the OMSIC model has been in place for more than a decade, disagreements have arisen on new multinodal dispatch models being developed. However, matters aggravate when having to determine the spot price at the time of energy shortages. In a bid-based scheme, the bidders rise the price to what the market allows, depending on supply and demand. In *the--Chilean* regulation, a nonserved load expected cost is defined, determined by the regulator and representing the cost to society of nonsupplied energy. It is determined through surveys to industry on the impact of shortages on production. Presently, it is 144.7 US mills/kWh. This value is used by the CDEC when planning future operation and use of water. It is also to be used for transfers among generators when there is nonserved energy. However, disagreement arose among CDEC participants, with deficit generators questioning the application of these regulations in such extreme unexpected conditions. The Minister of Economy recently ruled that the non-served load expected cost is to be used. However, the deficit generators have announced appeals to the decision.

Another matter that is being questioned by participants in the CDEC-SIC is the procedure used by the National Energy Commission to determine regulated prices to final consumers, particularly in these extreme conditions. As noted, to ensure price stability, regulated "nodal prices" are set for 6-month periods, based on projected marginal costs in the system. However, by using expected hydrological conditions to simulate system operation and determine future expected spot prices, the method has made nodal prices diverge strongly from actual spot prices. While the later have inflated steeply due to the severe drought, the nodal prices continue to decrease, reflecting an increasing contribution from additional combined cycle units to be installed in the near future. Several parties have questioned the economic logic of the regulation, where scarcity of supply coexists with reducing prices to final consumers, stimulating growth of demand. Consumption in the SIC had a yearly growth of almost 8 percent to January 1999.

Regulatory Changes

The disagreements in the pool arose long before the extreme drought developed. The regulator, through the Minister of Economy, has been essentially directing the actions of the pool, with no interest to do so. Therefore, a new bylaw was introduced in 1998 with changes to the decision process as well as to the operation of the pool. An arbitration expert committee is to assess differences before they are brought to the Minister, making recommendations to the CDEC governing board. The regulator expects that this learned intermediate body will help solve most disagreements.

The bylaw also makes it compulsory for each CDEC to create an independent control center, managed by independent staff specially hired, in what could be defined as an independent system operator, although it will depend on the CDEC decisions. Previously, the system was loosely operated through agreements among CDEC participants.

The new bylaw also increased the number of participants in the CDEC (transmission, smaller generators), maintaining main decisions based on unanimous agreements. The decision to maintain unanimous ruling was very much conditioned by the danger of market power.

No actions of the regulator are envisaged on the price system, although discussions have taken place on the advantages and disadvantages of evolving from a cost based scheme to a bid based one. Recent modeling work by the author at Catholic University of Chile has focused on assessing the price impacts of a bid-based scheme. Initial findings, based on simulations with noncooperative game theory, suggest an increase on almost 30 percent in average energy prices, in part due to the high concentration of plant ownership. These findings will be reported at a later stage.

About the Panelist

Hugh Rudnick was born in Santiago, Chile, and graduated as a civil electrical engineer from the University of Chile, later obtaining his MS and PhD degrees from the Victoria University of Manchester, United Kingdom. He is a professor of electrical engineering at the Catholic University of Chile, Santiago, Chile. His research activities focus on the economic operation, planning, and regulation of power systems. He has been a consultant with utilities and regulators in Argentina, Bolivia, Central America, Chile, Colombia, Peru, and Venezuela. He is a member of the IEEE PES Governing Board as Latin America representative to the board.

Electric Sector Reform in Peru

Mario Calmet, Jaime Guerra

The results achieved by the utilities of the Peruvian electric sector in 1990 showed a series of indicators that revealed that the electricity service had failed to reach its main objectives. The electrification coefficient was 48 percent, well below of other Latin American countries, which was about 80 percent. The annual consumption per capita of electric energy reached approximately 450 kWh, with the average in Latin America being in the order of 1,000 kWh. The reliability of the service had worsened dramatically, to the extent that it was necessary to ration the electric supply due to the lack of appropriate reserves for dry years.

Investment in the electric sector was very small, basically due to the low electric tariffs (below US$0.5

cents per kWh), which was not enough to cover the operation and maintenance costs. In addition, the private investment in the sector was practically nil, with the unique exception of the client's forced payment for the construction of distribution systems, which later became part of the assets of the electricity company.

As a result, this electric structure led to low productivity: 115 clients per worker for the whole sector in 1990, the average in other Latin American countries being about 300. The accumulated economic losses were about US$3 million for the period 1980-1990 and the external debt of the sector approximately US$3.5 million.

Reform Objective

The objective of the reform of the Peruvian electric sector was to establish the basis for a strong electric sector, able to assure an opportune, reliable, and adequate service to the society, with prices compatible with the economic costs of the operation and expansion of the service. With this objective, the Electric Concessions Law was enacted on 6 November 1992, and its regulations were approved on 25 February 1993. Together, these provide the legal framework for the conduct of all activities related to generation, transmission, distribution, and commercialization of electricity.

New Electric Sector Structure

The new structure of the electric sector established by the law and regulations has the following characteristics:

- Defines the government's role as normative, regulatory, and controller
- Redefines and reinforces the regulatory institutions and those in charge of the economic operation of the system
- Separates the generation, transmission, and distribution activities into independent companies, establishing competition in generation, providing open access to third parties in the transmission systems, and recognition of efficient standard distribution
- Establishes concession contracts as a requirement for the activities that use natural resources, property of the government and/or require the imposition of rights of way, with service obligations
- Establishes a price system that stimulates efficiency in the supply of electric service, penalizes the lack of quality and the lack of security, and promotes investment in new installations
- Establishes indemnities to customers for inefficiencies in the electric service,
- Establishes rules and procedures for developing generation, transmission, and distribution activities, fixing prices and tariffs for electricity, and establishing the rights and duties of the electric concessionaires and customers.

Electric Sector Agents

The agents of the electric sector are:

- Concessionaires and authorized agents who are natural or legal persons, national or foreign, that develop generation, transmission or distribution activities in accordance with the Electric Concessions Law and its regulations.
- Final clients who constitute the electric market composed of free clients (CL) with a contracted capacity higher than 1,000 kW and regulated clients (CR) with a contracted capacity equal or lower than 1,000 kW.
- Regulatory entity which is the Electric Tariffs Commission (CTE), a technical and decentralized office with functional, economic, technical, and administrative autonomy, responsible for setting the electric tariffs according to the criteria established in the Electric Concessions Law and its regulations. It consists of five directors proposed by government entities. Directors are persons having no labor relationship with their nominators.
- Normative entity is the general direction of electricity (DGE) of the Ministry of Energy and Mines is in charge of the establishment of complementary norms for the application of the law and its regulations.

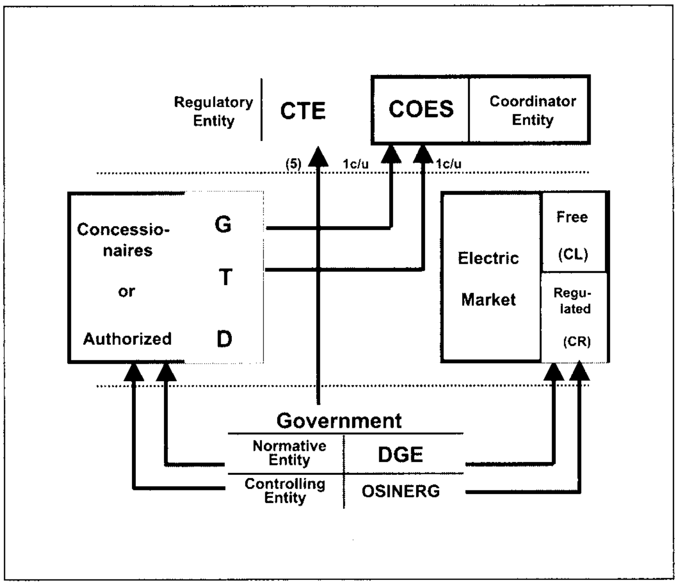

Figure 4. Agents of the Peruvian electric sector.

• Controlling entity is the supervisory body for the Investments in Energy, OSINERG, an autonomous entity whose role is to control the activities in the electricity and hydrocarbons subsectors with regards to compliance with the legal framework.

• Coordinator of the economic dispatch.

The Committee for the Economic Operation of the System (COES) was created as the entity in charge of the coordination of the economic dispatch in each interconnected system. It is composed of one representative from each generation company and one from each transmission company that owns the main system.

Figure 4 shows the relationship between the agents of the Electric Sector:

Electric Business

The types of electric business are as follows:

• As a generator

Between generators, by transfer of power and energy at the short-term marginal cost determined by COES as a result of economic dispatch

Sale of power and energy to the regulated market at regulated tariffs to distribution companies Sale of power and energy to the free market at free prices to generation or distribution companies and free clients.

• As a transmitter

With generators for transmission costs at regulated tariffs With distributors for transmission costs at regulated tariffs With free clients for transmission costs at regulated tariffs.

• As a distributor

Sale of power and energy to final regulated clients at regulated tariffs

Sale of power and energy to final free clients at free prices With generators for transmission or distribution costs at regulated prices.

Electric Market

Market Segments: According with the Electric Concessions Law and its regulations, the electric market is formed by the following segments:

• Free market, which is constituted by those final clients whose contracted capacity is larger than 1000 kW; they generally correspond to long term businesses at unregulated prices and transactions are made with firm capacity and energy.

• Public service market, which is constituted by regulated clients whose contracted capacity is equal or lower than 1000 kW; they correspond to long term businesses at regulated prices and transactions are made with firm capacity and energy.

• Intergenerators market, which is constituted by the transference of capacity and energy between generators by economic dispatch that correspond to short term businesses at short-term marginal costs.

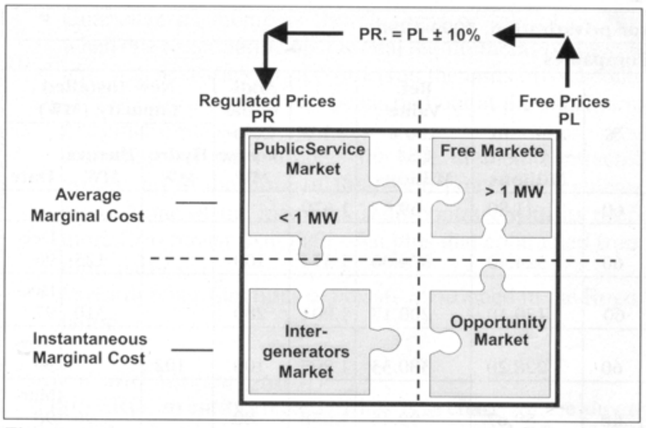

Figure 5. Peruvian market segments

• Opportunity market, which is constituted by sales of capacity and energy, according to availability, correspond to short term businesses at free prices and transactions made with non-firm energy. Figure 5 shows the segment markets.

Relationship Between Free Prices and Public Service Tariffs: The average tariff for public service clients cannot differ more than 10 percent of the average free price, for the same conditions of service.

Prices and Tariffs

Price Regulation: The following are subject to price regulation:

• Transfers of power and energy between generators, which are determined by the COES (This does not apply for the portion that exceeds the firm capacity and energy of the buyer.)

• Compensation to the owners of transmission systems

• Sale from generators to distributors destined for the public service of electricity

• Sale to public electric service (regulated clients).

The sale of electricity not mentioned explicitly in the above list is not regulated; that is, it is subject to the supply and demand of the market.

The public service of electricity is constituted by the regular supply of energy for collective use to clients with a contracted capacity not higher than 20 percent of the maximum demand of the distribution concession with a cap of 1,000 kW. The free clients are those with more than 1,000 kW of contracted capacity.

Basic Concepts: The basic concepts that govern the settlement of electric tariffs are:

• Economically Adapted System: The system of lower cost that satisfies efficiently the demand of electricity, maintaining the quality of the service, during the period for which the tariff is set.

• Marginal Cost: The cost incurred for the production of one additional unit of energy.

• Rationing Cost: The value attributed to the client for not providing him with energy. It is the average cost incurred by the clients in the absence of energy and the necessity of obtaining it from alternative sources. In the tariff calculation, the investments in the electric systems are remunerated with 12 percent interest. This rate can only be modified by the Ministry of Energy and Mines, on the basis of a study made by a specialized consultant assigned by the Electric Tariff Commission.

Investments of the enterprises and the clients are recognized. In this last case, the enterprises are obliged to issue bonds, stocks or any other kind of real devolution, which should be of the client's preference.

In case of a service failure, the law establishes a penalty for generators and distributors, which is paid to the clients, according to their average consumption. This penalty is paid at the cost of rationing for the nonsupplied energy.

Tariff Settlement: The Electric Tariff Commission sets the tariffs as follows:

• Bus bar tariffs: Each 6 months between 1 May and 1 November

• Connection toll: Annually from 1 May

• Tariffs formulas for regulated clients: Every 4 years from 1 November.

In the periods between tariff settings, readjustment formulas are applied monthly. These formulas are published together with the tariffs setting. Accordingly, the distribution concessionaires must publish the tariffs in real values, resulting from the application of the tariff formulas issued by the Electric Tariff Commission.

Bus Bar Tariffs: To guarantee a competitive market in the electrically interconnected systems, open access has been established to the transmission system for generators, who shall pay the correspondent compensation for investment and operation and maintenance costs.

For regulated clients, the Electric Tariffs Commission sets bus bar prices, taking into consideration generation and transmission costs.

Transmission systems consist of the principal transmission system and the secondary transmission systems. Transmission costs are determined by the investment and operation and maintenance costs of the economic adapted system, which are included in the tariffs as a connection toll and a tariff income paid by the users of those systems.

The connection toll is included in the bus bar tariff for capacity and, the tariff income in the bus bar tariff for energy. The connection toll of the principal transmission system is paid by all generators connected to the system in proportion to their firm capacity.

To cover the generation and transmission costs, the investment and operation and maintenance costs, the basic bus bar tariffs are determined as follows:

- Basic capacity price, which considers Capacity cost (P): Annuity of the most economic generation plant that covers the peak Connection toll to the main transmission system (PX):

  Calculated with the new replacement value of the economic adapted system Basic capacity bus bar price = P + PX

- Basic energy price (E) that considers the media of short run marginal costs of the next 48 months Basic energy bus bar price = E

In order to consider the losses in the transmission system, the basic capacity bus bar price and the basic energy bus bar price are extended through the losses factors, calculated by the average power flow for the next 12 months.

Public Service Tariffs: The distribution concessionaires are obliged to supply electric service to each client that asks for it within his concession area or to those who arrive to that area with their own lines within a period of time no longer than a year. This obligation is only for public service. Likewise, they are obliged to maintain valid contracts with generation companies that guarantee their demand of energy and capacity, for the next 24 months as a minimum.

The cost of distribution for regulated tariffs is calculated for economic adapted systems, considering a model company with operation and efficient maintenance costs and standard losses.

The basic tariffs for final clients include:

- Bus bar tariffs, which compensate the generation and main transmission costs
- Costs of Secondary transmission system, when it corresponds
- Distribution aggregate value, which compensates the distribution costs.

The distribution aggregated value is formed by:

Table 1. Peruvian electric sector privatization, 1994-1998

Generation Companies

Date	Company	Winner Consortium	Installed Capacity		%	Amount US$ Millions	Ref. Value 100% us$ Millions	$/kW	Additional Compromise MW	New Installed Capacity (MW)		
			Hydro	Thermal						Hydro MW	Thermal MW	Date
25-Apr-95	Cahua	Sindicato Pesquero	41.5		60	41.80	69.67	1.679				
17-0ct-95	Edegel	Generandes Co.	525	140	60	524.40	874.00	1.314	100		125	Dec-96
12-Dec-95	Etevensa	Consorcio Generalima		200	60	120.10	200.17	1.001	280		310	Dec-97
25-Jun-96	Egenor	Inversiones Dominion	225	90	60	228.20	380.33	1.207	100	102		Nov-99
02-0ct-96	E.E. De Piura	C. Electrico Cabo Blanco		60	60	59.67	99.45	1.658	80		96	Mar-98
Total			**791.5**	**490**		**974.17**	**1,623.62**	**1.267**	**560**	**102**	**531**	

Distribution Companies								
Date	**Company**	**Winner Consortium**	No. of Clients at Privitization Date	%	Amount US$ Millions	Ref. Value 100% us$ Millions	$/Client	No. of Clients Dec. 1998
12-Jul-94	Edelnor	Inversiones Distrilima	540,696	60	176.49	294.15	544	761,706
12-Jul-94	Luz del Sur	Ontario Quinta AW	466,341	60	212.10	353.50	758	643,087
15-Dec-95	EDE Chancay	Inversiones Distrilima	46,469	60	10.40	17.33	373	70,580
27.Jun.96	EDE Canete	Luz del Sur S.A.	17,000	100	8.60	8.60	506	22,203
ll-Feb-97	Electrosurmedio	Consorcio Hica	86,826	98.2	51.28	52.22	601	94,730
25-Nov-98	Electronorte	Grupo Gloria	140,786	30	22.12	73.73	524	141,487
25-Nov-98	Electronoroeste	Grupo Gloria	156,961	30	22.89	76.28	486	161,587
25-Nov-98	Electrocentro	Grupo Gloria	246,087	30	32.69	108.97	443	249,538
25-Nov-98	Hidrandina	Grupo Gloria	283,228	30	67.88	226.26	799	288,203
Total			**1,984,394**		**604.44**	**1,211.05**	**610**	**2,433,121**
Grand Total					**1,578.61**	**2,834.66**		

• Fixed cost of billing and invoicing

• Standard investment, operation, and maintenance costs associated with the distribution activity by unit of power supply

• Standard losses.

The calculation of the distribution aggregated value takes into account typical distribution sectors, which are classified by technical characteristics, electric load and investment costs.

For the November 1997 - October 2001 period, the following sectors were established:

• Typical Sector 1: Urban high density

• Typical Sector 2: Urban medium and low density

• Typical Sector 3: Rural urban

• Typical Sector 4: Rural

For each of them, the ADV is estimated to conform the basic tariffs.

The Electric Tariff Commission calculates the revenues for groups of concessionaires, considering the basic tariffs to final clients. If the revenues calculated do not differ more than four percentile points in comparison with the 12 percent established by Law, those tariffs are maintained. In other case tariffs are proportionally adjusted, in such a way to reach the nearest upper or lower limit, (8 or 16 percent, respectively).

The regulated tariffs are structured in medium and low voltage with different options, which are chosen by the clients, according to their load curves.

Coordination of the Electric System Operation

Objectives: Each interconnected system has a Committee for Economic Operation of the System (COES). Each COES is composed of representatives of the generation and transmission companies whose facilities comprise the interconnected system. The objectives of the COES are to plan the operation of the interconnected system at minimum cost, to ensure safety and quality of electric supply and optimize the use of available energy resources.

Functions of COES: The basic functions of a COES are to:

• Plan the interconnected system operation making the best use of available energy resources, applying established economic and security criteria, and communicating the resulting programs to its members, so they can operate theil facilities according to them

• Control compliance with the operation programs and coordinate the main maintenance programs for the facilities

• Calculate the short-term marginal costs of the electric sys tern according to the procedure established in the regulation

• Calculate the firm power and firm energy of each one o the generation units according to the procedure established in the Law and Regulation

• Guarantee its members the purchase or sale of energy, when due to economic operational requirements of the system, it is necessary to stop or to run the units off-schedule (These transactions are to be carried out at the short-term marginal costs of the system.)

• Guarantee all the members the sale of their contracted power, up to the limit of their firm power, at regulated price. None of the members shall contract with its users more firm power than their own plus that contracted from third parties

• Perform other functions expressly mentioned in the Regulation.

Control and. Service Quality

OSINERG, an entity created by law is in charge of the supervision of the electric service quality, as the controlling entity of the activities developed by the electric and hydrocarbon subsectors. It is part of the supervising system of the investment in energy, to which the Electric Tariff Commission and the Institute in Defense of the Competitiveness and the Intellectual Property (INDECOPI) belong.

Functions: In the electric service activities, OSINERG controls:

• Accomplishment of the norms that regulates the quality and the efficiency of service

• Accomplishment of the obligations of the concessionaires established in their concession contract and the obligations established in the Electric Concessions Law and its rules

• Accomplishment of the functions assigned by the COES

• Other aspects related with the supply of electricity.

Technical Quality Norms: The technical quality norms for the electric supply service were approved on 11 October 1997. The norms address the control of the electric service quality in the following aspects:

• Product quality: voltage, frequency, flicker, and harmonics

• Supply quality: interruptions

• Commercial service quality: treatment of the client, level of attention, measuring precision

• Public lights quality: inefficiencies in the service.

Client's Compensations: The norms establish the quality indicators to be met by the electric public service and the client's compensation if they are not met. The application of the norm is given in the following consecutive stages:

• Stage 1: This has a duration of 18 months, in which the entities involved in the electric supply service are obliged to acquire the equipment and install the infrastructure for the measuring and registration of the quality parameters. In this stage the electric companies must organize a pilot campaign of measuring and registering, for which they will present a program for application of the norm in the first 6 months. This stage begins with the approval of the norm and ends on 11 April 1999.

• Stage 2: This has a duration of 18 months in which the transgressions to the tolerances of the quality indicators generate reduced compensations established in the norm. This stage ends on 11 October 2000.

• Stage 3: This stage will start on 12 October 2000 at which time the transgressions to the quality indicators generate full compensations established in the norm.

Results

After 5 years of the Peruvian electric sector reform, the majority of the share capital of the generation companies and the
most important distribution companies are in private hands. Table 1 shows the privatization experience from 1994 to 1998. The newly installed capacity between 1993 and 1998 is over 720 MW in the central northern interconnected system, of which 520 MW are from privatization compromises and 200 MW from private initiative.

There is an equipment plan that assures satisfaction of the demand, with a capacity reserve of about 40 percent in the interconnected systems. In the medium term there is a plan to interconnect the two main systems, thereby creating the national interconnected system.

The electric tariffs are set with different options that can be chosen by the customers according to their load characteristics, in medium and low voltage supply, independent of the activities developed by them. Such tariffs reflect the system marginal costs.

There are two Committees for the Economic Operation of the System, both for the central northern and southern interconnected systems.

At the end of 1998 the electrification coefficient had reached about 70 percent. The Peruvian electric sector represents an installed capacity of 5,600 MW and an annual production of 17,500 GWh. The electricity sector consists of two main interconnected systems, the central northern interconnected system (SICN) and the southern interconnected system (SIS), plus several isolated regional systems and smaller systems. The SICN has the largest installed capacity and supplies electricity to approximately 12.6 million inhabitants. The SIS supplies electricity to approximately 2.5 million inhabitants and the isolated systems supply electricity to approximately 2 million inhabitants.

About the Panelists

Mario Calmet graduated as an electrical and mechanical engineer from Universidad Nacional de Ingenieria in Lima, Peru. He then did post graduate studies in England, France, United States, and Japan, where he was involved with generation and transmission systems, rural electrification, and the administration of electrical power companies. He has worked in the Ministry of Energy and Mines, Peru, as rural electrification division chief (1966-1971) and director of Electric Control (1972-1977), with the Commission of Electric Tariffs as Technical Secretary from 1983 to 1993, and with COES-SICN as director of Operations from 1994 to 1998. He collaborated in the elaboration of the Peruvian Electric Sector Reform (1992-1993). He also has worked as consultant for the United Nations and the World Bank. Since 1999 he has been a principal consultant of Hagler Bailly S.A. He is an IEEE senior member.

Jaime Guerra graduated as an Electrical and mechanical engineer from Universidad Nacional de Ingenieria in Lima, Peru, and later obtained his MS and PhD degrees from the University of Manchester Institute of Science and Technology (UMIST), UK, where he was involved in research related to computer simulation of electrical power systems, computer graphics and power system protection. After many years as a university professor in Lima and a consultant with utilities and government agencies, he joined COES-SICN in 1995, where he is currently working as director of Operations. He is an IEEE senior member.