Reliability in the New Market Structure
(Part 1)

The Plenary Session of the 1999 IEEE Power Engineering Society (PES) Summer Meeting focused on Reliability in the New Market Structure. The session was sponsored by the PES Plenary Session Committee, Education and Industry Relations, and moderated by Wallace S. Read. Presentations were as follows:

- Reliability and Generation Adequacy, by Ignacio J. Pérez-Arriaga, commissioner, Spanish Electricity Regulatory Commission
- Reliability in Latin America’s New Market Structure, by Hugh Rudnick, professor of electrical engineering, Catholic University, Chile
- Reliability and the Market Place: Perfect Together, by Michiel R. Gent, president, North American Electric Reliability Council (NERC)
- Legal Responsibility for Reliability in the New Competitive Electricity Markets in Canada, Andrew J. Roman, partner, Miller Thomson LLP, Toronto, Canada
- WSCC Reliability management System, by Dennis E. Eyre, executive director, Western Systems Coordinating Council.

This two-part article summarizes the Plenary Session. Part 1 includes summaries of the presentations given by W.S. Read, W.K. Newman, I.J. Pérez-Arriaga, H. Rudnick, and M.R. Gent. Part 2 will include a summary of the presentation by A.J. Roman.

The Challenge: Reorganization and Reliability
Wallace S. Read

Most of us have been inundated with messages on the need for change in almost every facet of our life style in order to cope with the new open global environment. This article offers yet another infusion of information about how our electric power utilities will fare in this competitive market.

Today’s world offers the electric utility industry a difficult but exciting challenge as we close out the twentieth century. That challenge is to organize itself so that utilities can compete in an open market for customer allegiance, while at the same time preserving a reputation for delivering a reliable, high-quality service. Obviously, if reliability and quality standards are not met, the customer base will erode and perhaps disappear, which is an untenable situation. Similarly, if the utilities’ commercial interests in the new marketplace are not maximized, company earnings can be placed in jeopardy.

However, we have not embarked on this restructuring of the industry to put utilities out of business. We must find the middle ground that ensures we deliver a quality service over a secure transmission network at the best possible price for customers and a fair return to shareholders.

How we meet these reliability and quality standards in a large integrated power system open to competition on the producer and consumer sides is quite different from how we met them when we operated in the traditional franchised mode of “cradle to grave” delivery of energy. Herein lies the difficulty for North American utilities. The separation of ownership of the components that make up the power system means a loss of control, or at best a sharing of control, over what constitutes a reliable service as we have come to know it. The management rules for this new delivery system will require careful planning by competent people.

It is not my intention to herald a return to the old ways. There are good and valid reasons for the changes in direction that are now taking place, and I believe these changes will go a long way to solve two threats to our industry:

- Alienation of customers: In the past, utilities faced nearly every customer relations situation in an autocratic, even arrogant manner. The world has changed. Customers no longer respond well to "command and control" tactics. New ways to relate to our customers must be sought, including the opportunity of building a partner relationship that provides customers with the information and wherewithal to control their energy use and to allow them to make appropriate energy choices.
- Alienation of the public: Utilities must ensure that they make every attempt to meet performance targets they have set for themselves, particularly when it comes to their impact on the environment. We have not always been good at it, but we are improving. Utilities in many parts of North
America have been labeled overstuffed, insensitive, and unresponsive. In the restructuring process, where this label applies, they must become more effective and efficient.

So, there is no turning back. The electric power industry, one of the last bastions of conservatism, has awakened to the fact that it is not immune to the pressure for change. It realizes that it cannot afford to bury its head in the sand when confronted with this challenge. But here is the dilemma. Any restructuring must not undermine the utilities’ reputation for reliable service. Customers may complain about prices, but they will never forgive unnecessary interruptions in supply.

Today, the electric utility industry in North America is undergoing a transformation unlike anything it has ever before experienced. It involves governments, regulators, shareholders, resource industries, and manufacturers. But, most importantly, it involves each one of us as consumers of electricity. Each interested stakeholder places a different priority on the kinds of change needed, and balancing these demands is a major challenge for our industry.

Disassembly of the traditional utility structure is taking form in response to:

- Pressures to privatize
- Competition in the marketplace
- Unrestricted access to the transmission network
- Customer choice demands
- Improved quality of service.

I believe that, in some quarters of our industry, the perception is that there is one magic deregulation model that all utilities worldwide should emulate. Nothing, of course, could be further from the truth. Deregulation will be a personal choice, different for different countries, and even different for different regions of a country.

This article focuses on a competitive market environment for electricity and the impact it will have on the way the utility industry serves society. It is about opening up the delivery system to permit competition at the generation level and customer choice at the distribution level. But, more importantly, it is about the consequences of these decisions and their impact on traditional utility obligations.

How will restructuring affect the reliability and quality of our electric power service? How will it contribute to improved customer satisfaction? What about the obligation to serve, customer rates at the lowest possible cost, a fair return to shareholders? These are the questions we explore with you.

About the Moderator

Wallace S. Read is president of REMAS Inc, which provides consulting services to electric power utilities and governments. He held senior positions with Newfoundland and Labrador Hydro, including president of Churchill Falls Corp., and president and CEO of the Lower Churchill Development Corp. He was president of the Canadian Electricity Association and a commissioner of the Public Utilities Board of Newfoundland and Labrador. He was the 1996 IEEE president. He is an IEEE Life Fellow and a Life Member of the Association of Professional Engineers and Geoscientists of Newfoundland.

Transmission Structure Issues

William K. Newman

The subject of electric system reliability can be approached from many angles: generation adequacy, bulk system operations, local distribution outages (by far the predominant cause of customer interruptions), transmission adequacy, and probably other areas. My comments focus primarily on transmission adequacy and bulk power system operations (generation and transmission).

Existing Grid

Primarily, the existing grid was designed and constructed to meet the needs of specific regions. Each region attempted to optimize the design of the transmission system within that region with consideration given to the design of neighboring systems. Most of the load within a region was typically served by generation within that region. The resulting grid was adequate to serve the known loads from known generating resources and was generally robust enough to accommodate contingencies on the grid and on adjacent neighboring grids.

Most of the interconnections between regions were constructed to provide increased reliability. The interconnections also allowed for economic interchanges of power on an as-available basis.

However, in some areas, the transmission system was indeed designed to accommodate large power transfers between regions. In every case that I know of, there were contracts for large power sales (and associated transmission contracts) that were agreed to before the transmission system was built to accommodate the resulting transfers. These contracts ensured that there would be transmission revenues to pay for the required transmission improvements.

It should be no surprise to any electrical engineer that a system designed for a specific purpose does not perform optimally for uses that were not contemplated in the design.

Reliability Concerns

The grid was not designed for the conditions that are now being experienced in the bulk electric system. The volume of transactions in, out, and through the grid has increased by approximately 50 percent per year for the last several years. In Southern Company’s control area, the 1996 peak-hour transactions were three times as many as in 1995. As would be expected with this volume of transactions, the loop flows have also increased. Until recently, little effort was made to associate resulting loop flows with the causative transactions. Indeed, no system existed a few years ago to even identify transactions across the Eastern Interconnection of North America.

Technical Issues

The demand on the existing information systems has increased exponentially with the increase in the number and complexity of transactions. NERC and other organizations are involved in developing systems to identify and track individual transactions. These tracking systems will help to optimize (maximize) the use of the existing grid. These efforts are essential and must be completed, regardless of the outcome of efforts to restructure the industry.

As regions merge and become larger, the existing energy management systems and security tools will become inadequate and will need to be replaced. The larger regions will need to install energy management systems with the capability of operat-
ing extremely large bulk power systems. This is a massive undertaking that will cost billions of dollars. Where will the money come from?

Numerous papers are being written about the need for construction of more transmission facilities or increasing the capacity of the existing systems to maintain grid reliability. There are many ways to accomplish an increase in the capability of the grid: construction of new lines, use of flexible ac transmission systems (FACTS) devices, better monitoring methods (local and wide area), and better control systems. All of these have the potential to help with the problem, but all are expensive and some present major policy challenges (construction of new lines for example). I have confidence that technical solutions will be developed, but they will not be adequate, by themselves, to address the overall challenges that we face in the transmission business.

Institutional Challenges

The eventual structure of the industry will have a major influence on how reliability issues are addressed. Today, many seem to believe that the formation of larger and larger regional transmission organizations (RTOs) will provide the solution to all of the problems. I am not yet convinced. The systems that are now being developed to plan and operate the grid will be required without regard to the ultimate decision on region size.

Regions are moving toward restructuring at different paces. State regulators have sent the message to federal regulators that states do not want a one-size-fits-all grand solution. It is tempting to advocate such a grand solution since the design and operation of the grid is so interrelated within an electrical interconnection. As tempting as this may be, we have not to date seen a region or independent system operator (ISO) that has solved the most significant problems in a fashion that would lead one to believe that the same solutions would be successful if applied across the North American continent. Having said this, there are some elements that must be common to any and all real solutions to the problems at hand.

Things We Must Have

We must have the ability to optimize the design of the grid. This cannot happen without knowing a projected pattern of load and generation locations. To have some confidence that projections of generator location will actually materialize we must have a method of pricing transmission that sends signals to the generation as to where they should locate to optimize the combination of generation and transmission. This must be done to achieve the maximum societal benefit. This sounds simple but most current pricing methods send very poor location signals to generators.

Even more important than technical considerations, the transmission business must be a viable, thriving, profitable business. Since most views of the future see transmission as a regulated entity, the regulators hold the key to the vitality of the transmission business. Recent rate decisions by the Federal regulators in the U.S. have sent discouraging signals to companies who want to stay in the transmission business.

Viable Transmission Business

The technical issues are huge, but they are solvable. NERC, EPRI, and others are moving forward to develop these solutions. The regional and regulatory issues are much harder to solve, but must be resolved. A one-size-fits-all solution is not required and is not desirable. Reliability standards developed by NERC will allow the operability of resulting regions.

Transmission is becoming a separate industry player and needs to develop a common voice on issues that are of universal interest to the transmission business.

A viable transmission business is critical to a successful competitive electricity market. All market participants will benefit from the development of a healthy, thriving transmission business.

About the Panelist

William K. Newman is senior vice president, Transmission Planning & Operations, Southern Company Services, Inc., responsible for planning and operation of the Southern electric system network transmission grid in order to provide economic, reliable service to all users. During his 18 years with Georgia Power, he worked in the areas of distribution, substation maintenance, test engineering, and system protection applications. He was an assistant to a senior vice president of Georgia Power before assuming the position of general manager, Power Operations at Mississippi Power Company, and then vice president, Power Generation and Delivery. He transferred to Southern Company Services in 1992 as vice president, Operation and Planning Services. He has served in a number of professional organizations dealing with reliability issues.

Reliability and Generation Adequacy

Ignacio J. Pérez-Arriaga

A few years ago, most electrical engineers could agree that power systems reliability was a mature topic, where most of the important ideas had probably been developed already and where, for the most part, only minor and highly technical improvements might be expected. It is amazing how the recent changes in the organization of the electric power industry worldwide have modified the traditional reliability issues and approaches so drastically, and how new ones have been created.

One has first to realize that the quality of service received by the end consumer, as the outcome of the global reliability performance of the power system, results from a chain of activities, where the most critical ones are generation, transmission, distribution, and system operation. Because of the intrinsically different characteristics of these activities, some of which can be performed in competition while others are natural monopolies that have to be regulated, they have been unbundled in the new market structure. Therefore, the contribution of each one of them to the reliability of the power system has to be examined separately.

In the traditional approach, each activity (e.g., distribution or generation) was considered separately also, but, within the perspective of a vertically integrated utility, the global objective was to provide a reliable service at minimum cost. Now, after the activities have been unbundled, for each activity, one has to provide the appropriate economic incentives and the regulatory norms that result in desirable reliability performance.
A key feature of the new competitive environment for the power industry is that the customer must be at the center of any business strategy. In a mature market, the customer must also have a say in reliability matters, mostly by making decisions on the reliability level of supply that he or she wants to receive and is willing to pay for.

This presentation introduces the basic regulatory guidelines that make it possible to address reliability issues in an adequate manner for each one of the relevant unbundled activities. These basic guidelines are meant only as an example of what can be done, but it should be acknowledged that a more complex regulation might not always result in a more reliable and efficient system. The topic of generation adequacy is covered in more detail, since the generation business and, in particular, investment in generation have changed dramatically with the introduction of competition. The initial experience on how some reliability issues are being dealt with within the context of the implementation of the internal electricity market of the European Union is described briefly.

Reliability Chain: Basic Regulatory Guidelines

Two distinct reliability products can be clearly identified in the generation activity: adequacy and security. Adequacy is concerned with the existence of enough installed and expected available capacity to meet demand. It is a medium- and long-term issue, although, it finally materializes in having or not having enough installed available capacity in the real-time. Security is the readiness of the existing capacity to respond whenever it is needed in operation to meet the actual load. It is a short-term issue.

Generation: The single major question concerning reliability in generation is whether the market can provide adequacy and security in a satisfactory manner or if some form of regulatory intervention is needed.

It seems that some kind of consensus is being reached regarding security in generation. The design of most recent wholesale electricity markets contemplates the existence of ad hoc markets for the provision of certain quantities of several required kinds of operating reserves. These quantities are mandated by the independent system operator (ISO). This scheme is working satisfactorily in the markets of Argentina, California, or Spain, for instance, and it can be considered to be a hybrid between the purely market and the interventionist approaches. On the other hand, adequacy in generation is still a very open issue, even conceptually.

Transmission: Transmission, which must be considered here as a separate activity from system operation, consists of the construction, maintenance, and physical operation of the transmission network facilities. Transmission is a natural monopoly, and it must be regulated as such. Some basic regulatory guidelines regarding adequacy of the transmission activity will be presented here. These guidelines must be contemplated within the context of a single system, i.e., the power system under a single ISO. The multiple-ISO case is briefly addressed within the European experience later in this presentation. In synthesis, the guidelines for regulation of transmission adequacy are:

- Transmission network planning should be proposed by the ISO, with the participation (via proposals) of the network users, and approved by the regulator.
- Once a facility is authorized, its construction, operation, and maintenance should be allocated by competitive bidding. Its remuneration should be based on the outcome of the competitive bidding process.
- The owner of transmission facilities should be subject to economic penalties (or incentives) based on the actual availability of the each individual facility.
- Transmission costs should be fully allocated to the network users using cost-reflective methods.

Distribution: By comparison with transmission, distribution (which is also a natural monopoly) cannot be regulated on the basis of the individual facilities, since there are too many of them, but on a basis of global performance. The regulator should set targets of quality of service and losses, with geographical differentiation. Network expansion, as well as network operation and maintenance, are left to the distribution utility.

The remuneration of the distribution network must be based on performance. Starting from a reference remuneration, based on an ideal network, an RPI-X method, or another scheme, penalties (also incentives) based on the actual quality of service and losses should be applied to attain the final income for the distribution network.

System Operation: The ISO is responsible for the security procedures in operation, but it should also be responsible for proposing the plan of transmission network reinforcements.

The remuneration of the ISO (which is also a monopolistic activity that has to be regulated as such) should be based on cost-of-service considerations. In addition, it is possible, although complex, to design economic incentives associated with the performance of the ISO. For instance, economic incentives could be associated with the reduction (with respect to a prescribed target) of the extra costs of dispatch derived from the management of network constraints. Incentives can also be applied in relation to the reduction of the costs of provision of ancillary services. International experience exists, e.g., in the National Grid Company of England & Wales, on how to implement these incentives successfully.

Issues and Options for Generation Adequacy

Generation adequacy is a complex issue on which there is a lack of consensus in the design of wholesale competitive markets throughout the world. The three fundamental questions, whose answers determine the regulatory option to be adopted on this issue, are as follows:

- Who has the ultimate responsibility for generation adequacy? If the regulator, who must intervene if a potential lack of capacity is detected? If it is left to the market, how should the commitments among the players, the product to be delivered, and the responsibility for the delivery be defined?
- For which ones of the existing designs of wholesale markets throughout the world can be stated that market prices fully remunerate the total costs of the generating plants, and the peaking units in particular? An ensemble of technical issues has to be examined in this regard: the elasticity of demand to market prices, the participation of the demand in the determination of these prices and the mechanisms to be adopted in the event that the market fails to provide enough supply to meet the demand. The existence and, if this is the case, the value of price caps for the market prices, as they will affect considerably the income of the peaking generating units.
- The correctness of the mechanism of determination of the market price, in particular the possible influence of mandatory levels of operating reserves in depressing the energy prices.
- The allocation of economic risks to buyers and sellers that
is implicit in a specific market design. This allocation will affect the use of financial hedging mechanisms and will influence the behavior of risk-averse potential investors.

- The customer should be the centerpiece in the electricity markets. However, how can the choice of the level of reliability of supply by the customers be implemented in the existing or future competitive electricity markets?

From these considerations, it must be clear that generation adequacy cannot just be left to the market. Even under a philosophy of minimal regulatory intervention, there are issues such as the participation of demand in the market, price caps or risk allocation that constitute fundamental regulatory decisions. Conceptually, one may classify the existing or proposed regulatory options with regard to generation adequacy in competitive markets into three broad categories (starting from the most interventionist option and ending with the most liberal one): capacity payments, capacity markets, and price risk-hedging contracts.

**Capacity Payments:** There are two principal motivations for this approach, which could be considered either independently or jointly. The first motivation for capacity payments is to partly stabilize the volatile income of generators, in particular of the peaking units, by establishing a low price cap for the market price and compensating the corresponding loss of income of generators by a stable remuneration of the available generating capacity. This may be considered a soft regulatory intervention. The second motivation is to directly promote an extra level of generation adequacy by establishing a capacity payment for the available generation capacity, which should contribute to stimulate new investments and to discourage early retirement of otherwise unprofitable units. This is clearly a hard regulatory intervention.

The practical implementation of this approach may vary. In general, the global amount (or the per-unit value) of capacity payments is established on the basis of the prescribed price cap value (first motivation) and/or of the target adequacy level (second motivation). Then, the payments to the individual generators are broadly based on some estimated measure of their contributions to the system adequacy and on the actual availability of each generator. Argentina, Colombia, or Spain are examples of systems that use capacity payments.

The ex ante method of computation of market prices in England & Wales (to be changed shortly) indirectly results in a capacity payment by overestimating the probability of loss of load for the next day. This capacity payment approach normally succeeds in providing a fairly stable economic signal to generators, but it has some important drawbacks. First, the economic signal, if not carefully implemented, may introduce distortions in the generators’ behavior in the short-term market. Second, it is very complex to find a convincing way of determining the volume of the payments and of allocating them to the different generators. Finally, and most important, this approach lacks the definition of an identifiable commercial product for which the generators obtain their remuneration. Therefore, there is nothing tangible that is really being paid for or that can be traded, there is no specific commitment from the generators’ side, and the desired level of adequacy cannot be guaranteed.

**Capacity Markets:** The motivation for this approach is to guarantee a regulated adequacy target for the system by defining specific commitments of purchase of firm production capacity to all the consuming entities. In this approach, the regulator directly defines the commercial product associated to generation adequacy.

The practical implementation of the approach consists of requiring mandatory levels of contract coverage of firm generation capacity to all consuming entities in the system: qualified consumers and any retailers purchasing power on behalf of either qualified or captive consumers. The level of mandatory coverage (e.g., 15 percent above the consumer’s estimated annual peak load) may be proposed by the system operator and authorized by the regulator. Interruptible load may also qualify as a form of providing firm capacity to the system. The transactions between buyers and sellers of firm capacity may be facilitated via organized long-term auctions, one or more years ahead of real-time. The committed capacity has to be available at the time of delivery, or else it will be subject to a heavy fine. However, the commitments of firm capacity may be traded in the short-term, if uncommitted capacity is still available. Argentina is considering to change to this approach, which has been adopted in the pools of PJM and New York in the United States.

In capacity markets, there is an identifiable commercial product associated to generation adequacy and a commitment by the agents to purchase and to deliver the product, although the precise definition of firm capacity and of the conditions of delivery require some care, particularly with hydro units. Market mechanisms determine the price of this product, which may be very volatile, depending on the tightness of the margins of installed capacity over the system peak load. The remuneration of the generators may not gain much in terms of stability with this approach. There is no choice of reliability level by the consumers, who are forced to accept the uniform level that is mandated by the regulator. Free riding would be possible if qualified consumers, for instance, were free to choose.

**Price Risk-Hedging Contracts:** The motivation for this approach is to facilitate maximum flexibility of choice to consumers in the provision of any desired level of reliability and to generators in the stabilization of their income. This approach requires a high level of maturity in the development of the power market, but it may also contribute to promote this maturity. The approach does not require any explicit regulatory intervention.

In this approach, there is no price cap that limits the market price. It is assumed that the elasticity of demand to prices is enough to prevent any occurrence of market failure to supply because of lack of generation adequacy. The customers who so wish may hedge their price risk, since there is no risk of lack of adequacy, by signing specific contracts with generators who want to hedge their risk of revenue volatility. The clauses of these hedging contracts may vary, but an example could be like this: Consumer pays prime P to generator for the right to receive a payment consisting of the excess of the market price M over an agreed strike price S over any consumed amount of electricity up to a maximum quantity Q during a time period T. In this way, the consumer pays a prime P in advance for the insurance that the price for the contracted amount of electricity will not exceed a chosen value S. The generator stabilizes its income by receiving a prime P in exchange for giving up potential high revenues if the market price happens to exceed S. A short-term market may be also established to trade these contracts and adjust them to the actual needs of the agents in the real-time. This approach is not been yet implemented in any existing power market.

This approach leaves total freedom of choice to both generators and consumers. Note that the existence of the contracts has an impact on the reliability of the system, by creating commit-
ments and economic incentives related to reliability, fully determined via market mechanisms. Generators with contracts have a strong economic incentive to be available at any time of scarcity of supply, where market prices may be very high. On the other hand, consumers without contracts will have to withdraw from the system when market prices become intolerably high. If, in spite of this, the supply is still insufficient to meet the demand under price risk contracts, the unavailable generators with contracts will try to buy back the contracts, i.e., to pay an amount to the customer for shedding its load.

This ideal approach requires a certain level of market maturity: elimination of price caps, actual response of consumers to system prices, a regulation that adequately balances the economic risk between consumers and generators, and correct mechanisms of determination of the market price. While captive consumers may exist, some party must have the incentive to act on their behalf; otherwise, the regulator may establish contracts for them, with the potential of creating free riding opportunities for other consumers. The primes of the contracts may also be volatile, depending on the levels of installed generation capacity relative to demand.

**Experiences within the EU Internal Electricity Market**

The internal electricity market of the European Union (EU) was established by the Directive 96/92/EC of June 1996 and started in February 1999. The directive sets minimum requirements of market opening, and, while several countries are well ahead of meeting these requirements, others have not yet finalized the transposition of their laws to comply with the directive. For instance, although the required market opening for each country should presently be at least 26 percent, the actual EU average is 63 percent.

The major task ahead in the implementation of the EU electricity market is harmonization of the different national regulations, particularly with respect to network tariffs and congestion management rules for cross-border transactions. Other issues, such as energy taxes and mechanisms for support of renewable generation, are also of importance.

An institution that is playing a relevant role in the definition of the rules for cross-border trading in the EU electricity market is the Electricity Regulation Forum that is convened in Florence twice a year by the European Commission. This is a meeting of the regulators (either independent regulatory commissions or ministerial representatives) of the 15 EU countries, plus Norway and Switzerland, which have special agreements with the EU on these matters. System operators of all of these countries are invited to the meetings.

In the May 1999 Florence meeting, broad guidelines for cross-border trading were adopted. They are summarized as follows:

- **Network pricing and congestion management must be treated separately.**
- **Network pricing must be based on the following principles:**
  - The local connection charge established by each country for its network users (consumers and generators) provides access to the entire EU network.
  - Some economic compensation must be established regarding the extra network costs incurred by some countries because of the physical flows that result from the trading activities of external agents. Each country will decide how to affect the network charges for its network users because of the extra costs or revenues resulting from these compensations.

The network costs in the area under a system operator must be fully recovered by the revenues from the transmission charges within this area.

Harmonization of network charges in the different countries (ratio of allocation of charges to consumers and generators; split of the charges into energy and capacity components, etc.) is a medium-term objective.

- **A specific approach for congestion management was not adopted.** However, the Italian, Portuguese and Spanish regulators jointly proposed a scheme, based on the following principles:
  - Congestion management should be based on common information provided by all system operators. This includes network data, usual generation patterns, and schedules of all cross-border transactions. A common network model and a computer tool for network analysis should also be available for all system operators.
  - Based on the common information and models, each system operator will identify any congestion occurring at its tie lines or within its internal network.
  - The pair of system operators involved in a congestion at their common border must eliminate the congestion by using market mechanisms (e.g., each transaction will have to bid for the use of a bottleneck), which must be compatible in time with the existing organized markets, the day-ahead markets in particular.
  - Only the transactions that have been accepted in the congestion management process may participate in the next-day markets or be executed.

Each system operator must solve its internal congestion.

The Forum of Regulators requested a technical proposal for implementation of the guidelines from the Association of European Transmission System Operators (ETSO). ETSO was created on 1 July 1999 by an agreement between four preexisting institutions: the former Union for the Coordination of Electricity Generation and Transmission (UCPTE), which in April 1999 became the Union for the Coordination of Electricity Transmission (UCTE), where the only members are system operators; the Nordic Electricity System (NORDEL), comprising Sweden, Norway, Finland, Denmark, and Island; the British Grid System; and the Electricity Supply Board of Ireland. ETSO is now a single platform for the coordination of the European system operators, whose main task now is the implementation of cross-border trade in Europe, following the established regulatory guidelines.

With respect to generation adequacy, the approaches in the fifteen EU countries are widely varied, and there is no perspective of harmonization in this respect. While traditional mandatory generation planning, accompanied by competitive bidding, continues in use (for instance in France and also partly in Portugal), other countries (such as Norway, Sweden, or Finland) have adopted a ‘leave-it-to-the-market’ approach, although they are presently considering some kind of regulatory intervention to keep enough peaking units in operation, such as the purchase of single-cycle gas turbines by the system operator. Regulated capacity payments are used in Spain and, in an ad hoc manner, also in England & Wales, although in the latter case they may be soon replaced by some scheme based on price risk-hedging contracts.

**About the Panelist**

Ignacio J. Pérez-Arriaga is commissioner of the Spanish Electricity Regulatory Commission. He held various staff posi-
or worked as an advisor in the development or revision of the regulation of capacity payments to enhance long-term guarantee of supply of generation in Spain, Argentina, and Colombia.

Reliability in Latin America's New Market Structure

Hugh Rudnick

The objective of this presentation is to provide an overview of deregulation of the electric power sector in Latin America and to focus on how the needs for adequacy and security (the long term and short-term elements of reliability) have been fulfilled (or not) in the new environment. Challenges arising with recent problems with supply are also discussed.

Deregulation

Latin America is a region in transition and growth where economic reforms with market economies are encouraging development, supported by increasing regional commercial exchanges. Latin America has an overall installed generating capacity of 190,000 MW, with an average annual growth of 5 percent, which implies capital investment annual requirements similar to those of Canada and the United States. It is a region where levels of electricity consumption are still low if compared to Europe and North America, leaving even more space for growth.

In the recent past, electricity was provided through vertically integrated state-owned utilities. They were the drivers for development, interconnection, and electrification, since the early 1950s. Companies such as Eletrobras in Brazil, Endesa in Chile, Comisión Federal de Electricidad in Mexico, Electroperú in Peru, just to name a few, played simultaneously the entrepreneurial and regulatory hands in electricity development.

However, that has changed almost everywhere. Latin American deregulated wholesale markets extend from the Rio Grande to Cape Horn. Chile was the pioneer in 1982, followed by Argentina in 1992, Peru in 1993, Bolivia and Colombia in 1994, Brazil in 1998, and Mexico being the latest one to formulate a project for change.

The reasons for deregulation and consequent privatization have varied from country to country. Inefficiencies in operation, maintenance, and management drove Argentina and Colombia into extended blackouts in the late 1980s. Financial deficit at the state level (for example, in Brazil) limited required resources for electricity expansion. Political changes driven by strong governments in Bolivia, Chile, and Peru made countries evolve into market economies where private power sector development was seen as the direction to follow. Finally, requirements from multilateral banks have been behind Central American reform. A main pressure behind deregulation and privatization has been the provision of sufficient investment to respond to the high growth.

Common characteristics of the changes include:

- Wholesale market deregulation, with unregulated prices for large consumers
- Competition at the generation level with centralized generation dispatch
- Short-term marginal cost-based schemes
- Transmission open access regulation with global allocation of network costs as the base for competition
- Incentive-based regulation for distribution

A central conceptual paradigmatic change, unnoticed by many, takes place in the reform process in Latin America. The previous state-owned monopolistic company was conceived as a public service company, with the obligation to serve, and it was protected for doing so. Each company supposedly played a social role, providing reliable energy with a secured remuneration over its investment and operational costs. The common criticism in Latin America was that reliability failed or, if achieved, it was done through inefficient over-investment.

With unbundling taking place and competition developing among private generation firms that offer a commodity at resultant prices, the obligation-to-serve concept disappears. Barriers to entry to investors in a competitive business are lifted; generators do not play a public service role, even though they are obliged to coordinate through a mandatory pool. It is only the regulated companies that are obliged to serve. The distribution company, at the end of the chain, has the obligation to supply energy in its franchised area and, at least in theory, transfers that responsibility through contracts with third parties. The transmission company also has an obligation to serve through the open-access requirement. These two regulated businesses can be stimulated to comply through adequate remuneration incentives and through penalties for not obeying.

Economic Incentives and Adequacy

But this is not evident in the competitive segment of generation. Ideally, in a perfectly competitive market, the market economic signals would drive investment to an optimum for adequacy and security of supply, and there would be no need for the regulator to intervene. But that ideal is not trusted in Latin America, and the regulator explicitly intervenes to provide required incentives for reliability to be secured. Different approaches have been followed.

One of the main challenges in the region is to respond to the high rates of growth in electricity consumption. The need is to stimulate private investors to compete and provide enough capacity on time to sustain economic growth. Adequacy becomes the main aim. The common element in Latin America has been the addition of a capacity payment. Besides paying for energy, consumers pay for use of capacity, measured at peak system demand. Capacity payments are transferred to generators contributing to supply maximum demand. Values around US$6/kW/month are used, with the value determined from the cost of investment and operation of a peaking gas turbine, assumed to be the cheapest source for peaking power.

A second element that some countries have chosen to stimulate expansion has been the definition of regulated generation tariffs to final small consumers. The regulator assesses what would be the optimal social expansion generation/transmission plan and calculates evolution of prices for that plan that would
Renewable investment is not a given rate of return. Generation is obtained and used for exchanges between operators and distributors supplying small consumers. One of the aims of restructuring has been to deliver price signals to ultimate customers that reflect the real cost of electricity supply, leaving traditional cross-subsidies and political rates as part of the past.

Those economic tools, particularly capacity payments, have sustained investment in power plants in the region. Investors from within the region (pension funds among others) and increasingly outside (European and North American investors) have not only responded to growth, but have changed the energy resources used while developing international energy interconnections. Highly efficient combined-cycle natural gas plants are being introduced in many countries, while international electricity and gas interconnections are growing everywhere. The Argentina-Chile gas exports, the Argentina-Brazil electricity interconnection, and the Bolivia-Brazil pipeline are only a sample of developments that will eventually drive us into a South American interconnected market. Even economically disadvantaged urban consumers are benefiting as electrification is extending through private actions.

My assessment is that economic incentives have worked, and, in general, adequacy has been achieved.

Reliability and Security

What about the short-term reliability? Security, as a short-term operational objective, in deregulated competitive environment, is very much dependent on a monopolistic activity, that of the system operator and the rules under which it is governed, as well the rules and standards of operation it has to follow.

The central question is how much freedom to give to the competing agents to pursue their economic objectives and how much coordination to impose. All Latin-American countries have followed the poolco approach to market organization, where a central body often acts both as a system operator and a market exchange. The governing of that body and its independence from the private agents are achieved in different forms in the various countries of the region, and security flows from that. The case is that the particular commercial interests of the agents or groups of agents may interfere in the secure operation of the system, and the chosen governance structure will allow it or not. The achievement of a secure supply in Latin America has been linked to the success in achieving a truly independent operator and the incentives for it to operate efficiently.

Argentina developed an institutional framework with a strong independent operator, governed by representatives from all classes (generators, transmitters, distributors, and large consumers) and from the government, and it has been successful in keeping out competitive commercial interests in everyday operation. Chile instead, chose operation through a generators club, troubled with disputes among participants that have failed to maintain adequate security levels.

But, it is not only the governing of the pool that conditions the reliability of the system. An important tool in Latin America to stabilize a secure operation has been the definition of penalties for actors not complying with minimum quality standards, reliability included. In weakly meshed systems, basic (n-1) criteria are not easily applied, and innovative approaches have to be developed to achieve minimum secure operation. Load shedding and load tripping are common approaches to maintain the backbones of interconnected networks.

My assessment is that the Latin-American deregulation processes in general have been successful in stimulating adequacy, investment for rapid expansion, but not necessarily for security. Pool regulations need to be improved to truly develop independent operators.

Challenges with Recent Supply Problems

Let me describe two recent situations in South America that have dramatically questioned the way the deregulated arrangements are responding with a secure supply. They are providing arguments to those few that long for the state-owned vertically integrated public utility which, according to them, provided a secure supply, while responding to the social needs of the countries. They question private investors competing in a market structure, who are more concerned with their profits and short-term results than quality and reliability of service.

Latin America is a region highly dependent on hydroelectric resources, and El Niño and La Niña have caused havoc in electricity supply. A difficult situation arose in Chile recently that questioned the logic of regulation. While the level of investment by the private sector was within that assessed as needed by the regulator, a centennial drought, coupled to the failure of a prototype combined cycle gas 350 MW plant, forced the implementation of a rotative blackout in the capital of Santiago. Both my house and my office building were without electricity for from 2 to 3 hours a day from March to May. Another economic incentive that had been coined in Chile did not work. Regulated small consumers paid generators an insurance premium by which they were secured supply even in drought conditions. Non-supplied consumers were to be paid by generators the cost of non-supplied energy (regulated at 16 cents per kWh). But the insurance coverage only considered historical hydrological conditions, which covered the last 40 years. The obligation to serve was limited to those scenarios. The drought was outside statistics, and no compensations were paid for blackouts. A public outcry blamed the privately owned generators for not investing enough, and accused them of only looking out for their own commercial interests.

Generators had invested reasonably well, as assessed by the regulator. The essential problem was that a very unusual condition made society realize that the cost of non-served energy was higher than that used to determine regulated tariffs and, in essence, to stimulate expansion. However, as a result of the crisis, a change of law took place in June in Chile, where the insurance coverage was made universal, irrespective of hydrological conditions. The impact that this will have on future private investment, adequacy, and resultant prices is to be seen. Although secondary to the origins of the crisis, it must be pointed out that the weak Chilean pool did not help sufficiently, and its use of limited hydrological resources has been questioned.

A second event that tested the strength of the regulator in stimulating reliability took place last February. A large-scale urban electricity blackout hit Buenos Aires, the capital of Argentina. Soon after a new 132 kV substation was inaugurated, a night fire broke out some central cables, plunging almost 160,000 homes, shops and restaurants into darkness, about 150 MW. Around two-thirds of those affected got their power back within 24 hours, but about 50,000 clients had to wait until the middle of the following week (up to 11 days) before service was fully restored. Without light and air conditioning (Buenos Aires was going through a summer heat wave), angry customers took to the streets in protest. Again, society realized that the cost of non-supplied energy was several times what it was assumed to be. The public even asked that private owners be stripped of the distribution concession, in which they have invested $800 million over the last 6 years. The regulator finally decided to im-
pose an exemplary fine, ten times the standard cost of nonsupplied energy (which was 1500 cents per kWh), that meant over $70 million were paid by the distribution company to final consumers. The critics have accused recent staff cuts and a lack of supervision as reasons why the fire was not controlled more quickly. Again, the public criticized private investors for aiming at increasing returns by reducing costs.

So, the overview is mixed. Latin American societies are pleased with deregulation and privatization of the power sector. Adequacy has been achieved through economic incentives for expansion, while at the same time prices are going down (generation prices have reduced over 50 percent in the main Chilean system in the last 8 years, while in Argentina a similar evolution took place in only 5 years). Security has been achieved in places where the system operator has been made truly independent. We have been successful where an adequate system of penalties and incentives has been incorporated.

But challenges arise every day. The two critical conditions that took place in Santiago and Buenos Aires are examples of the issues we face, where technical questions mix with economic ones in a complex way.

The obligation-to-serve concept and its treatment under the new deregulated structure in the region is a matter of discussion. Requirements for improved quality of service are being introduced after years of power market deregulation, but the question remains open on how high a degree of reliability is desired in electricity supply in a developing world.

About the Panelist
Hugh Rudnick is a professor of electrical engineering at Catholic University, Chile. His research and teaching activities focus on the economic operation, planning, and regulation of electric power systems. He has been a consultant with utilities and regulators in Argentina, Bolivia, Central America, Chile, Colombia, Peru, Spain, and Venezuela, mainly on the design of deregulation schemes and transmission and distribution open access tariffs. He is a member of the PES Governing Board.

Reliability and the Marketplace: Perfect Together

Michel R. Gent

I believe that electric system reliability and the marketplace are "perfect together." The North American Electric Reliability Council (NERC) is changing to accommodate the forces of electric industry restructuring, increasing competition, and the opening of the transmission systems to new participants.

NERC hopes to continue its reliability oversight role for the United States and Canada with an aggressive plan to transition itself into the new North American Electric Reliability Organization (NAERO).

NAERO will be an electric industry self-regulating reliability organization (SRRO) with the basic objectives of setting reliability standards and enforcing compliance to those standards in a fair and non-discriminatory manner, while maintaining the competencies that have made NERC successful over the past 30 years.

Two principles that have become our watchwords during this transition effort are "independent" and "market solutions." I think we all know what independent means, and none of us are quite sure what market solutions mean. As we become more attuned to the commercial environment, our successes will be measured not only by how reliable the grid remains, but how well we embrace and adapt to market-based solutions.

Regional Councils and Interconnections

Most of you here today have heard of NERC and the ten regional reliability councils, whose responsibility is to promote the reliability and adequacy of bulk electric supply by the electric systems of North America. These regional councils in 1968 formed a not-for-profit umbrella organization called the National Electric Reliability Council, which, in 1981, was renamed the North American Electric Reliability Council to reflect Canadian membership. These regional councils are the "owners" of NERC.

Every electricity provider, transmission provider and user, and customer is in one of the ten regional councils. Each council is different. In most cases, the councils were developed independent of each other to serve the needs of the utilities in their respective areas.

The regional councils in the United States, Canada, and the northern portion of Baja California Norte, Mexico, do not operate as a single synchronous grid. In fact, NERC is composed of three grids or interconnections. Because these grids are not operated synchronously, each interconnection historically has had its own rules, procedures, processes, and even language. Over time, NERC has striven to make all of these interconnections more uniform, however, remnants of that heritage remain today. As electricity commerce commences, one of our most difficult challenges is going to be to make the commercial rules more uniform across all of the councils. In fact, the commodities people tell me that regionalization is the single largest impediment to an efficient North American electricity market.

Beginnings of Change

NERC's initial transitional activities to address the new electricity market began in the early 1990s. The U.S. Energy Policy Act of 1992, which many believe gave the U.S. Federal Energy Regulatory Commission (FERC) the authority to order open access, did not come as a surprise. In preparation, NERC passed several resolutions, one of which was that all NERC "policies" would be mandatory. The NERC board of trustees wrestled with this notion of voluntary versus mandatory, and vowed that all of its procedures, policies, and standards would indeed be mandatory. The problem is that NERC does not have any way of enforcing the mandatory requirement other than peer pressure. Other board resolutions led to a report that we call "NERC 2000." During the development of this report, NERC resolved to open up regional membership, include independent power producers on the NERC Board, and provide for alternative dispute resolution.

The biggest event in NERC's history since the 1965 blackout was FERC's "Open Access" Notice of Proposed Rulemaking in 1995, followed by the final rules (Orders 888 and 889) issued in 1996. All utilities now have to open their transmission systems to any responsible party that is willing to pay for access. FERC also told everyone what they could charge and how they had to
make the information available. Even today, at least half of our staff’s time is spent trying to address the substance of Orders 888 and 889.

Issuing the FERC NOPR had more impact on NERC than actually passing the 888 and 889 rules. What the NOPR did was to begin NERC’s transition, and we ultimately ended up with a security coordinator system, a way of computing available transfer capability, a way of dealing with ancillary services, and a system operator certification program.

NERC also had in mind that utilities should “voluntarily” form organizations that would provide for additional transmission where needed and to otherwise remove transmission bottlenecks. Three such organizations known as regional transmission associations were formed in the western part of the United States and Canada. We also have independent system operator (ISO) organizations formed in California, Texas, New England, New York, and PJM.

**NAERO Guiding Propositions**

With reliability and related commercial issues being pushed NERC’s way, the NAERO board, in May 1997, recruited a blue ribbon panel of independent, well-known, credible experts who were viewed as providing an independent perspective on how NERC should be organized to maintain reliability in the new electricity operating environment. The panel recommended the best ways to set, oversee, and implement reliability policies and standards for the interconnected bulk electrical systems in North America in a competitive and restructured electricity industry. There were no limits on the panel’s advice. In fact, the NERC staff was directed not to participate, and to only speak when spoken to. The panel’s product was in no way to be influenced by the NERC staff.

The panel’s report and recommendations were essentially all accepted by the NERC board in January 1998. Since that day, NERC and the regional councils have been building toward NAERO. The panel’s report became the beacon that lights the way for NERC’s transformation. The guiding propositions in that report state that a new electric oversight system is needed, and essential competencies should be preserved. Further, the new electric oversight system should be able to enforce reliability rules. And, most importantly, NERC needs to keep you, the folks who operate the electric power systems, involved. That’s what the panel was saying when it said that essential competencies should be preserved.

**NAERO Concepts**

The electric reliability panel came up with the concept for an organization, which we have called NAERO. The governments of Canada, the United States, and Mexico would provide grants of authority, in some fashion, to a certified industry self-regulating reliability organization (SRRO), namely NAERO. This SRRO would, in turn, assure the governments that the interconnections will be operated in a fair and even-handed manner, and that an acceptable level of reliability will be maintained.

The SRRO will manage the setting, monitoring, and compliance of reliability standards. This compliance would be backed by the regulatory agencies of the governments. Regional reliability implementation agreements (RRIA) will be the basis of how the standards setting, monitoring, and compliance will be implemented. A variety of opinions exist on what needs to be included and spelled out in the RRIA. However, to see that the reliability rules would be developed and implemented in a fair manner, the SRRO would delegate authority to what we call regional reliability organizations (RROs). These RROs could be the regional councils or not; we don’t know yet. But there will be some regional organizations that will be expected to implement the standards and ensure compliance by the RRO participants with the NAERO standards.

Now, who’s supposed to be a member? Today, market participants and stakeholders are members of the regional councils, and the regional councils are the “members” of NERC. But that will change. Membership in the new organization (NAERO) will be very different. Those organizations whose operations affect the reliability of the interconnections must be members of NAERO. NERC’s panel called them system operator organizations. Today, the system operator organizations would be what we think of as control areas, ISOs, or security coordinators. It is quite possible that the system operator organizations’ definition will be expanded to something else. These operator-type organizations will also be required to be a member of the RRO in which they operate.

**NAERO Governance**

In the end-state, nine independent board members will govern NAERO. I think this was the most difficult decision the electric industry had to make. Some say we arrived at the independent board because it was the only way to ensure fairness. Others say that we could not agree on an acceptable mix of stakeholders, and the independent board was the compromise. Whatever the reason, we have agreed to a nine-member independent board, and we have moved forward on this decision. The independent board members were elected in January 1999 to the NERC board and currently serve in parallel with the existing NERC board members. When NAERO becomes the SRRO and certain other conditions regarding grants of authority by the U.S. and Canadian (and Mexico, when appropriate) governments are made, as well as when funding is decoupled from the ten regional councils, the nine independent board members alone will govern NAERO operations.

Among NERC’s transition efforts, it has replaced its former NERC Operating Committee and Engineering Committee with three new standing committees, which became effective in May 1999; a Security Committee, an Adequacy Committee, and a Market Interface Committee. Each committee’s membership (31 plus a chair and vice chair, all voting members) still holds somewhat of a regional flavor with 13 representatives from the three NERC interconnections. But more attention has been paid to the market segment with 18 representatives. A number of regulators and observer representatives comprise the approximately 5 to 10 nonvoting committee members. The committees are functional today, and their meetings are open to anyone.

NERC’s Security Committee will have most of the responsibilities of the old Operating Committee. Its main mission will be to develop operating standards to ensure security or short-term reliability of the interconnected systems. The Adequacy Committee has many of the functions of the former NERC Engineering Committee. The Adequacy Committee’s new tasks are to develop planning standards that will ensure the reliability of the interconnected systems, and assess and encourage long-term adequacy.

The Market Interface Committee is new to NERC, and I think it’s worth mentioning. There was an electric industry group that NERC facilitated called the Commercial Practices Working Group. That group elected to become part of NERC/NAERO. Some from the old school still think any activity that covers the marketplace should be independent of NERC.
We can change at any time, but today we have the Market Interface Committee. That committee’s main functions are to address NAERO reliability standards from the commercial perspective, assist in addressing the impacts of new and evolving market practices on electric system reliability, and provide an open forum for the discussion of market interface issues.

In addition to the three standing committees, two additional functions have been set up in NERC. They include an open due-process procedure for the development of the NERC reliability standards and a compliance enforcement program. The compliance program is composed of a compliance director and staff, who will be responsible for conducting compliance reviews and ensuring compliance with the NERC reliability standards.

The compliance enforcement program will become the strong arm of NERC. It will be a separate and independent function, and its staff will answer to the NERC president and the NERC board. The three key elements of the compliance program are:

- Compliance review process for all the NERC Planning and Operating Standards
- Enforcement process that will include penalties and other sanctions
- Oversight of the system operator certification program.

I’d like to add that to date about 2,000 system operators have taken the system operator certification examination with a 94 percent passing grade. I’m very proud of all the system operators that had the initiative to take this exam. We are ahead of schedule. We’ve had at least twice as many take the exam as we envisioned. We had feared that only about a fourth of this number would have taken it by now. By the year 2001, all operators on duty will have been licensed and certified.

NERC’s new standards development activity is also under way in which careful attention is being paid to process, openness, and fairness. The content of the NERC planning and operating reliability standards is the industry’s responsibility. Everyone is invited to participate in this public due-process review and development of NERC standards. NERC is also continuing to look for ways to integrate its standards development process with the Power Engineering Society’s standards process and that of the American National Standards Institute (ANSI) in the United States and the Standards Council of Canada.

State of Transition

NERC is changing and will continue to change. We’ve added independent board members for NAERO governance. We’ve reorganized the NERC committee structure and added a Market Interface Committee. We are developing standards through the NERC due-process review procedure, and have begun the implementation of a NERC pilot compliance program.

Compliance enforcement has a lot of hurdles. We are trying to implement a pilot compliance program that works primarily through the regions and the NERC staff, and we are struggling. Enforcement of standards with associated penalties and/or sanctions will begin sometime after legislation is passed and NERC (NAERO) is certified or accredited as the SRRO. In the meantime, NERC continues to use volunteerism and peer pressure to develop, review, and implement its standards and policies.

So what’s the bottleneck? We think that, to do this right and to do this quickly and fairly, we need to have federal U.S. legislation to provide for the creation and oversight of an industry self-regulating reliability organization. The electric industry feels very strongly about the creation and oversight responsibilities of an industry-based SRRO. They have, therefore, developed suggested consensus language for legislation to be approved by the U.S. Congress. Major associated industry organizations have signed a letter indicating they agree with the electric industry’s proposed legislation and have delivered this endorsement to Congress. We are hopeful that the U.S. Congress and necessary grants of authority in Canada will come to fruition for NERC in the next year or less.

But what will happen if we don’t get legislation? That’s what I call “Plan B.” The Western Systems Coordinating Council (WSCC) has implemented a reliability management system, a voluntary compliance program based on contracts. If we don’t get legislation, I will try to propagate this approach throughout North America. I will also go to FERC and ask them to include in an ad hoc tariff a reliability service that will fund all of the regional councils in NERC. I am prepared to do that if we don’t get legislation. So you can see we really need legislation. I’ve been told that Congress may act only if there is an emergency. I want to dispel this last notion. I’m not looking for a blackout to prove to the U.S. Congress that we need to have a reliability bill.

The ball is in the U.S. Congress’s court. We can’t enforce compliance to the reliability standards until we have the authority, but will move forward with the organization and act like we can. To stress the urgency of the need to be able to enforce compliance and demonstrate our good faith in transitioning to this new organization, everything is on the fast track in NERC. In the beginning, the new entrants complained that NERC was not moving quickly enough. Now, their complaints tend to be just the opposite.

To ensure that the electric industry and its customers stay in control of their own destiny, and in control of reliability, NERC has a plan. We’ve put that plan on display for all to see and for all to comment.

If you truly believe as I do that the market will provide, then we need to find ways of removing barriers that are preventing the market from providing. Only you, the electrical engineers of the world, can do this. Turn your hats around and find ways to make this work. It will work a lot better if you are working for a fair and efficient marketplace than if you are working against it.

I look forward to your support of NERC today and the new NAERO tomorrow.

About the Panelist

Michel R. Gent is president of the North American Electric Reliability Council (NERC). He joined NERC in 1980 as executive vice president, before which he served for 7 years as the general manager of the Florida Electric Power Coordinating Group, a voluntary power pool for all of Florida’s electric utilities. He worked for 10 years with the Los Angeles Department of Water & Power, where he held several responsible position in operations and planning. He has also taught in the graduate schools of University of Southern California and Loyola.