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PROFILES ON ELECTRICITY ISSUES

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INDEPENDENT SYSTEM OPERATORS

Overview. The advent of a fully competitive generation market and retail direct access in the power industry has refocused attention on the system operator and the need for *independent* operational control of the interconnected transmission grid. A competitive generation market requires an impartial "traffic cop" with the plenary authority to enforce grid reliability in much the same way that the airline industry needs a single, independent air traffic control system. The establishment of regional independent system operators or ISOs would accomplish similar objectives, as well as others, in the electric industry. The ISO's responsibilities extend from real-time operation to the long-term planning of the grid as necessary to maintain and improve reliability and meet the operational needs of a competitive electricity marketplace. The ISO would operate the grid on a nondiscriminatory, common-carrier basis in order to remove any anti-competitive advantages in the generation markets which might arise from the joint ownership or control of transmission and generation facilities by any entity.

The purpose of an ISO is to preserve and expand existing operational procedures and guidelines for ensuring the reliability of the interconnected grid, but on a basis wholly independent of the owners of grid assets. The ISO administers a grid-wide, open-access transmission tariff, and supports market trading activities by providing on-line, real-time access to information on network conditions, ancillary services, and other market support data and services. The ISO is strictly prohibited from engaging in any market activities for its own benefit. Finally, the ISO performs the long-term planning of the grid and recommends necessary enhancements or the expansion of transmission facilities. The ISO's bylaws and organizational structure should be tailored to meet and enforce these basic responsibilities.

ELCON believes that, properly structured, implemented, and operated, ISOs can be essential components of a competitive electricity marketplace.

PROFILES ON ELECTRICITY ISSUES are published to promote a better understanding of the economic and social impact of policy proposals relating to electricity. ELCON members seeks an adequate and reliable supply of electricity at competitive prices, not only for the benefit of industrial consumers and their labor force, but also for all consumers of industrial products and the U.S. economy.

Profiles on Electricity Issues

INDEPENDENT SYSTEM OPERATORS

CONTENTS

SUMMARY OF ELCON'S POSITION ON INDEPENDENT SYSTEM OPERATORS (ISOs)

1. **ISO'S MISSION** -- A competitive electricity marketplace requires the formation of large, regional independent system operators (ISOs) to ensure that:

   - The safety and reliability of the interconnected grid is adequately maintained and improved;
   - All market participants have equal and nondiscriminatory access to transmission services at just and reasonable rates approved by the Federal Energy Regulatory Commission; and
   - The timely addition of new or enhanced transmission facilities are planned for and built.

2. **ISO GOVERNANCE** -- An ISO should be a non-profit organization created with the full participation of all potential market participants. The ISO's governance structure should be representative of all market participants. Equal representation should be given to constituencies representing suppliers and end-use consumers. Governing board membership and voting procedures must prevent control by a single constituency or any minority representative group voting as a block.

3. **ISO RESPONSIBILITIES** -- An ISO administers the regional, open-access transmission tariff and supports market trading activities by providing on-line, real-time access to information on network conditions, ancillary services, and other market support data and services. The ISO is also responsible for establishing guidelines for maintenance scheduling of all transmission facilities and the restoration of the ISO grid after any emergency condition. All generators must coordinate their maintenance schedules with the ISO to avoid reliability problems and any potential exercise of market power.

4. **ISO CONTROL AREA** -- The ISO region or grid should be a single control area subject to the exclusive real-time operation and control of the ISO. The ISO must have functional, and operational control over all FERC-jurisdictional transmission facilities and where necessary, any local distribution facilities with transmission-like characteristics. There should be no control areas or sub-control areas within the ISO grid except as arranged by, and subject to the control of, the ISO.

5. **OPERATIONAL CONTROL OF TRANSMISSION FACILITIES** -- Transmission owners should be required to enter into contractual arrangements such that the real-time operational control of all transmission and transmission-supporting generation assets are turned over to the ISO. The generation assets subject to such control should be the minimum necessary to comply with NERC standards and ensure system reliability against all major system contingencies, and to accommodate all requests for access to the ISO grid that do not impair reliability.

6. **OPERATIONAL UNBUNDLING AND COMPARABILITY** -- Any transmission-owning utility that maintains separate generation, distribution, and/or wholesale or retail marketing affiliates should be required to take all its transmission services, including services for retail sales, under the same ISO tariff as other users. That utility and any of its affiliates must also use the ISO OASIS to arrange those services, like other market participants.

7. **ANCILLARY SERVICES** -- The ISO should ensure the competitive provision, where feasible, of ancillary services consistent with FERC rules and regulations.

8. **ATC, OASIS, AND GENERATION REDISPATCH** -- The ISO's primary market support responsibilities are the calculation of available transfer capability (ATC), making that and related information available to all participants by posting it on the ISO OASIS, and promptly responding to service requests. The ISO should dispatch generation only as necessary for real-time system balance and the maintenance of reliability. The ISO should redispatch generation, only when necessary, to meet system emergencies, and/or accommodate transmission service requests on a real-time basis.

9. **MARKET INDEPENDENCE** -- The ISO should not make the market, guarantee market outcomes according to preconceived technical rules or guidelines, or interfere in any way such as to prevent market clearing prices from reflecting the combined economic behaviors of buyers, sellers, and independent market intermediaries. The ISO should not attempt to design or operate a spot market in electric energy services. The ISO is strictly prohibited from engaging in any market activities for its own benefit.

10. **ISO PLANNING RESPONSIBILITIES** -- The ISO should be responsible for the long-term planning of the ISO grid as an on-going administrative function internal to the ISO. This planning function must ensure that the ISO grid is adequately maintained and expanded to improve reliability and accommodate growth and other market changes in the most economically efficient manner feasible. If necessary, the ISO should take the necessary steps to form a new, independent corporate entity to bear the responsibility for constructing new facilities.

11. **ISO OPEN-ACCESS TARIFF** -- The ISO should administer the grid-wide, open-access transmission tariff on a nondiscriminatory basis. The tariff should provide load-based network service with postage-stamp rates based on rolled-in embedded costs, plus a separate charge for losses. The tariff structure should explicitly account for and internalize loop flows and mitigate any "pancaking" of rates. Rates should be provided in advance and not assessed retroactively.

12. **TRANSMISSION CONGESTION MANAGEMENT** -- The costs associated with most occurrences of congestion, wherever located, should be averaged across all users in the postage-stamp rate. The establishment of separate pricing "zones" within the ISO grid is only justified where congestion conditions are extremely severe and one group of market participants is discriminated against for the benefit of another. An important ISO planning responsibility is to anticipate and relieve transmission congestion by making appropriate operational changes and by ensuring timely construction of enhancements or additions of new facilities. ###

Profiles on Electricity Issues

INDEPENDENT SYSTEM OPERATORS

A. INTRODUCTION

This *Profile* describes ELCON's recommendations for the major operational, technical, and organizational features and responsibilities of independent system operators (ISOs). The document intends to help the reader understand, appreciate, and advocate a pro-consumer and pro-market perspective in the ongoing debate on ISOs and the crucial role they may perform in a more competitive electricity industry.

The laws of physics require some form of real-time system operator as long as future loads cannot be predicted with absolute certainty and other operational and emergency contingencies exist. Under traditional cost-of-service regulation, the typical vertically integrated utility met most of its retail sales requirements with its own, mostly local generation resources. That utility, more often than not, operated its own control area.[1] The system operator's responsibilities were initially the preservation of system reliability by ensuring that generation and load were matched at all times. Over time, the operator's duties were expanded to include economic dispatch of the utility's own generation, and engaging in off-system sales and purchases, especially to market excess generation capacity. Today, these responsibilities are defined and subject to guidance and potential enforcement by the North American Electric Reliability Council (NERC) criteria and guidelines.

The advent of a fully competitive generation market and retail direct access in the power industry has refocused attention on the system operator and the need for *independent* operational control of the interconnected grid. A competitive generation market requires an impartial "traffic cop" to operate the grid on a real-time basis and enforce grid reliability in much the same way that the airline industry needs a single, independent air traffic control system. The establishment of a regional ISO will accomplish similar objectives, and others, in the electric industry. The ISO should operate the grid on a common-carrier basis in order to remove any anticompetitive advantages in the generation markets which might arise from the joint ownership or control of transmission and generation facilities by any entity.

On April 24, 1996, in its landmark rulemaking on open-access transmission tariffs, *Order N° 888*, the Federal Energy Regulatory Commission (FERC) issued eleven general principles that the agency will use in assessing ISO proposals subject to its jurisdiction (see box on page 5). FERC encourages the formation of ISOs and believes that "properly constituted" ISOs are a means by

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[1]A control area is an electrical system, bounded by interconnection metering and telemetry. It continuously regulates, through automatic generation control (AGC), generation within its boundaries, and scheduled interchange back and forth across the interties, to match its system load while contributing to frequency regulation of the interconnection. (See "Definitions" at the end of this *Profile*.) Some utilities operate a control area jointly in a "tight" power pooling arrangement.

FIGURE 1

FEDERAL ENERGY REGULATORY COMMISSION
ORDER 888
PRINCIPLES FOR THE ESTABLISHMENT OF INDEPENDENT SYSTEM OPERATORS

1. The ISO's governance should be structured in a fair and nondiscriminatory manner.

2. An ISO and its employees should have no financial interest in the economic performance of any power market participant. An ISO should adopt and enforce strict conflict of interest standards.

3. An ISO should provide open access to the transmission system and all services under its control at non-pancaked rates pursuant to a single, unbundled, grid-wide tariff that applies to all eligible users in a nondiscriminatory manner.

4. An ISO should have the primary responsibility of ensuring short-term reliability of grid operations. Its role in this responsibility should be well-defined and comply with applicable standards set by NERC and the regional reliability council.

5. An ISO should have control over the operation of interconnected transmission facilities within its region.

6. An ISO should identify constraints on the system and be able to take operational actions to relieve those constraints within the trading rules established by the governing body. These rules should promote efficient trading.

7. The ISO should have appropriate incentives for efficient management and administration and should procure the services needed for such management and administration in an open competitive market.

8. An ISO's transmission and ancillary services pricing policies should promote the efficient use of and investment in generation, transmission, and consumption. An ISO or an RTG, of which the ISO is a member, should conduct such studies as may be necessary to identify operational problems or appropriate expansions.

9. An ISO should make transmission system information publicly available on a timely basis via an electronic information network consistent with the Commission's requirements. (Note: These requirements are specified in *Order 889*, the OASIS rule.)

10. An ISO should develop mechanisms to coordinate with neighboring control areas.

11. An ISO should establish an ADR (*i.e.*, alternative dispute resolution) process to resolve disputes in the first instance.

which public utilities can comply with the Commission's nondiscriminatory transmission tariff requirements.

A paramount reason for establishing ISOs is the fact that complete divestiture of regulated and unregulated corporate functions is difficult in the United States under existing law and practice. Nonetheless, an ISO's operational control of transmission assets must be equivalent to the degree of control had the ISO, in fact, owned all those assets. The establishment of ISOs is also an essential component of a broader public policy to require complete financial or corporate unbundling of the traditional vertically integrated utility monopoly. This policy ensures that the potential for anticompetitive practices between regulated and unregulated corporate functions are minimized by requiring corporate structures that lend themselves to minimal, but effective regulatory oversight and other government intervention. This policy appropriately protects the interests of captive customers to the regulated affiliates without impairing the marketing opportunities of unregulated affiliates.

B. Establishing An ISO: Agreements and Contracts

Each ISO should be created with the full participation of all potential market participants. Any effort by transmission owners or regulators to exclude from the process any existing or potential market participants, or to preserve existing coordination or pooling protocols and organizational features, should be opposed. Each ISO should have a charter, bylaws, and articles of incorporation. The ISO must be vested with plenary authority to enforce its directives.

The establishment of an ISO will require one or more agreements or contracts which bind the parties to certain obligations. For example, separate agreements may be needed to address: (1) the structure and operation of the ISO; (2) the assignment of operational, functional, and jurisdictional control to the ISO, and the residual rights of transmission owners'; (3) regional reserve planning obligations; (4) the administration of the grid-wide transmission tariff, the OASIS[2], and other regulatory requirements; and (5) the ISO's planning responsibilities. The openness of the negotiation process, the manner in which the parties decide which and how many separate agreements should be crafted, and what the intent of each should be, have powerful effects on the ultimate empowerment of the ISO organization, and the separation and enforcement of responsibilities among the ISO participants and transmission owners.

An ISO agreement should establish the ISO as a non-profit entity subject to FERC jurisdiction.[3] The ISO agreements and contracts also must address ISO governance, budget approval and audit processes, enforcement and dispute resolution procedures, conflict of interest requirements and codes of conduct for employees, and fair compensation for transmission owners.

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[2]OASIS or "Open-Access Same-Time Information System" is intended to be an on-line interactive data and communications service that allows a transmission user to determine how much transmission capacity is available, what it costs to use it, and to arrange any necessary ancillary services. An OASIS might also allow buyers and sellers of any tradable service to consummate a sale on line.

[3]Under the Federal Power Act, an ISO that "operates" facilities used for the transmission of electric energy in interstate commerce or the sale of electric energy at wholesale in interstate commerce is a "public utility" subject to FERC jurisdiction. An ISO will also be subject to FERC's open-access and OASIS rules (*i.e.*, Orders 888 and 889).

The final agreement or contract on operational control should stipulate that the ISO become a member of NERC because the ISO will be the operator of the NERC-defined control area. The ISO will also need to become a member, as necessary, of one or more Regional Reliability Councils (RRCs). The ISO will be the responsible entity for complying with all applicable NERC and RRC operating and planning policies, procedures, principles, guides, and standards. Transmission-owning utilities may continue to participate in NERC committee activities, but those utilities must remain subordinate to the ISO.

Public policy on the formation of ISOs should encourage fewer, larger ISOs to be formed so as to avoid inefficient market balkanization and rate pancaking, and to facilitate the internalization of inadvertent flows. ISO operating agreements should provide for mergers with neighboring ISOs, and start-up/implementation costs should be carefully controlled to minimize the "stranding" of such costs resulting from any mergers.

C. The Mission of An ISO

Many agreements to form a new organization begin with a statement of "Purposes," often in the form of a series of "whereas'" clauses. In the context of an ISO, these purposes set both the philosophical and practical boundaries within which the ISO and market participants are expected to operate and cooperate. From a consumer perspective, each "Purpose" should be supportive of customer choice and the efficient operation of a competitive electricity market. They must also evoke, in the strongest language possible, a commitment to a truly "independent" ISO with actual physical control of the ISO grid vested with the ISO. Essential purposes are: (1) real-time operational control of the ISO grid for safety and reliability purposes; (2) the mitigation of market power in the absence of divestiture; (3) market facilitation, not control; and (4) a strong internal planning function. These purposes must accommodate and advance retail direct access, reduce costs and improve operating efficiencies, and not serve to delay or frustrate the onset of customer choice.

D. ISO Governance

1. Board of Directors

System operation and transmission access have almost always been subject to the exclusive control of a vertically integrated monopoly. Separating control from ownership of the relevant assets raises property rights issues since most transmission assets and system control centers are owned by private investors. This problem can be addressed by carefully defining ISO operating and governance rules and the composition of the board of directors. The ISO board should be the chief policy and decision-making body of the organization, and the equivalent of a corporate board of directors. Therefore, board representation must be broad and accommodate the widest possible participation by potential users. There must also be a balance between end-use consumer and supplier representation, including market-making entities such as power marketers and exchanges.

Existing utilities and transmission owners have a legitimate role in any ISO board. But IPPs, marketers and brokers, public power entities, and other wholesale supplier entities traditionally excluded from power pools and RRCs, also justifiably deserve representation on ISO boards. With the advent of direct access to the interstate grid by end-use customers, it is also imperative that their

representation on ISO boards is at least equal to the representation of supplier interests.[4] ISOs that form before direct access has been implemented in all states contained within the ISO region must include full representation by end-use customer interests regardless of when the right of choice is granted to such consumers.

To accommodate and balance the interests of various end-use customers and supplier groups, board membership and voting procedures must prevent undue control by a single constituency or a minority group voting as a block. Any voting procedure based on transmission revenues, the rate-base value of assets, or other weighing scheme serves only to perpetuate the monopoly control of transmission owners and must not be allowed. Such formulas are carry overs from traditional power pool agreements (*e.g.*, NEPOOL and PJM) and are not suitable models for the operation of ISOs in a competitive industry.

The original design for the California ISO Governing Board, one of the first such proposals, is illustrative. Anywhere from 2 to 5 directors were appointed to represent five constituency classes dominated by supplier interests. The numbers were chosen such that no two classes constitute a majority vote of the board and no single class could veto an action. This board structure could lead to a large, potentially unwieldy number of board members. Nonetheless, while lacking adequate end-user representation, this model is a good place to start from a consumer perspective. There is no justification for preserving club-like governance or voting procedures common in old power pool agreements.

Board members should be nominated by their respective constituencies and not delegated to government authorities in order to avoid unduly politicizing ISO governance. For the same reason, the establishment of mandatory governmental or legislative oversight bodies -- other than the minimal FERC purview required under the Federal Power Act -- should also be avoided. Guidelines and rules for board membership qualifications and credentials, membership termination procedures, code of conduct, and conflict of interests standards should be spelled out in the ISO bylaws. These guidelines and rules must promote the principle of fair and equal representation by all entities with a vested interest in a reliable and competitive electricity marketplace.

2. Responsibilities of the Board of Directors

The ultimate authority of the ISO should be vested with the board of directors. Certain additional authorities are vested with federal regulators and self-regulating industry bodies in the form of NERC guidelines and FERC rules and regulations. These additional authorities are binding on the ISO. Potential responsibilities of the ISO board include:

- Enforce or change ISO operational procedures and agreements
- Determine reliability standards in compliance with NERC guides

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[4]Public power entities, such as municipal utilities and rural cooperatives, are wholesale suppliers and should not be considered representative of end-use customer interests.

- Issue standards for participation in the ISO markets for ancillary services and access to the ISO OASIS
- Create standing and advisory committees
- Create an audit committee to review audit matters, enforce conflict of interest standards for ISO employees, and enforce compliance with established rules and standards
- Resolve disputes between market participants and ISO staff
- Review and adopt the ISO budget, operating plans, and annual reports
- Review and approve FERC regulatory filings and long-range ISO grid expansion plans
- Recommend, for FERC approval, changes to the Board's membership structure
- Hire/fire the ISO Chief Administrator

From a consumer perspective, the centralization of broad authorities with the ISO board is important. The ISO must have at least the same physical, functional, and jurisdictional control over the system as the utility's "system operator" had over the same assets in the old market structure. Any dilution of those authorities may preserve market power with the joint owners of transmission and generation and compromise the efficient operation of a competitive power market and the independence of the ISO.

E. ISO STRUCTURE

The purpose of an ISO is to preserve and expand existing operational procedures and guidelines for ensuring the reliability of the interconnected grid. In addition, the ISO acts to facilitate a competitive electricity market by providing -- and ensuring -- nondiscriminatory access to the transmission network and ancillary services.

The ISO administers the grid-wide, open-access transmission tariff, and supports market trading activities by providing on-line, real-time access to information on network conditions, ancillary services, and other market support data and services. The ISO is strictly prohibited from engaging in any market activities for its own benefit. Finally, the ISO coordinates the long-term planning of the grid and recommends necessary enhancements or the expansion of transmission facilities.

The ISO's organizational structure should be tailored to these basic responsibilities and include the following separate functions:

1. CHIEF ADMINISTRATOR

The chief administrator or executive director should be appointed by the ISO Board of Directors and oversee the day-to-day operations and administration of the ISO and ISO staff.

2. SECURITY OPERATIONS DEPARTMENT

The ISO Security Operator ensures the reliable operation of the regional control area, all local sub-control areas, and contributes to the reliability of the entire interconnection. The ISO Security Operator will also be responsible for coordinating the restoration of service after a system contingency at both the regional and local levels.

3. MARKET SUPPORT DEPARTMENT

The ISO Market Support Department administers the ISO OASIS; provides transmission services, and develops and maintains the grid-wide transmission tariff; and coordinates the provision of ancillary services with the Security Operations Department. The ISO may also provide ancillary services. The activities of this department are to facilitate fair and impartial market access for all transmission users.

4. PLANNING DEPARTMENT

Under the direction of the ISO Board, the Planning Department performs, evaluates, and reviews system studies (*e.g.,* generation reserves, abnormal system conditions, and major outage contingencies); prepares all necessary load flow studies; recommends and directs enhancements or expansion of transmission facilities; and participates, as necessary, in other joint coordinated transmission planning efforts assigned to the ISO in cooperation with state siting boards and commissions, and other regional bodies established for this purpose.

F. OPERATIONAL CONTROL

1. LEGAL OBLIGATIONS

In order to work, the ISO must assume some degree of control over the area generation and real-time operational control over the transmission facilities of transmission owners. All transmission utilities within the ISO region must be part of the ISO. How this operational control is surrendered and enforced is one of the most contentious issues involved in establishing the ISO. At one extreme, divestiture or forced leasing of transmission and generation assets is often proposed. The ISO would own the assets or operate them under a lease. At the other extreme, transmission owners retain full control of their assets and the ISO would *advise* the owners to take certain actions whenever any predetermined contingencies arose. The transmission owners, under an ISO agreement, presumably would agree to comply with the ISO's recommended course of action on a best-efforts basis.

One means by which utilities are attempting to preserve control of the system is by insisting on the preservation of subcontrol areas -- subject to their continued operational control -- within the ISO grid. These subcontrol areas are usually existing control areas that conform to the boundaries of the old franchise areas. This issue is further discussed, below, under "Control Areas."

At a minimum, transmission owners should be required to enter into a contractual arrangement by which control of transmission and certain generation assets previously under its

direct control, is turned over to the ISO. The only rights that the owners should retain are those specifically identified in the contract. These assets, which would be physically operated by the ISO, should be the minimum necessary to ensure system reliability against all major contingencies. This level of direct control is necessary to ensure that the ISO is the NERC-responsible entity for maintaining reliability as defined by NERC reliability guidelines.

Another important issue related to operational control is operational unbundling. A transmission-owning utility that maintains separate generation, distribution, and wholesale or retail marketing functions should be required to take all of its transmission services, including services for local area retail sales, under the same ISO tariff as other users. That utility must also use the ISO OASIS to arrange those services, like other users. Mandatory divestiture need not be a consideration during the transition to a competitive industry structure if vertically integrated utilities volunteer to operational unbundling and the ISO is assigned complete physical control of the regional grid.

In addition to a system control room for real-time monitoring and operation of the ISO control area, an ISO must directly operate and control all FERC-jurisdictional transmission facilities. In some control areas, certain distribution facilities -- with transmission-like characteristics -- should also be controlled. This is necessary wherever the operation and/or configuration of local distribution facilities can significantly affect the transmission system.

Some ISO proposals have attempted to restrict the ISO's authority by limiting such control to only certain "designated" transmission facilities. Often these facilities are the extra-high voltage interties, leaving most lower voltage facilities that directly serve end users -- including large end users who take service at transmission voltages -- under the operation and control of the utility. From a consumer perspective, an ISO's authority should err on the side of controlling too much, rather than too little. There is little downside risk (or cost) to controlling too many wires, substations and transformers, switches, and phase-shifters -- as long as transmission owners are fairly compensated for the use of their assets. As a long-term objective, ISO control of the combined transmission and distribution grids should be explored.

2. CONTROL AREA

The reliability of the interconnection remains the ultimate responsibility of each control area. In order to implement that responsibility, a system operator must exercise plenary control of the control area. It is critical that an ISO has the authority to operate the NERC-defined control area and energy management system (EMS) system for the ISO grid. The responsibilities that ensure adequate functional control include: (1) all monitoring, reporting, and operating functions of a control area, such as the preparation of reports to FERC and NERC; (2) monitoring and reporting of control performances (*e.g.*, inadvertent interchange or "loop flow" accounting); (3) scheduling transactions with parties outside the ISO, and assuring the availability of ancillary services for all market participants; (4) the calculation and allocation of reserve obligations; (5) operation of the supervisory control and data acquisition (SCADA) systems; and (6) the operation of breakers, reactors, capacitor banks, and other switchgear.

Generally, the ISO should be a single control area, although there is no reason the same ISO cannot also operate more than one subcontrol areas. However, the consolidation of the many

existing control areas into as few control areas as possible should be an objective of industry restructuring. Such consolidation should be designed so as not to sacrifice either reliability or market efficiency.

Under some limited circumstances, subcontrol areas may need to be established, each with a separate operations center. The ISO board, and FERC, should approve all such arrangements. Otherwise, attempts to balkanize the ISO grid into subregions or subcontrol areas are unacceptable for the following reasons:

- **Fragmented Communications and Decision-making** -- The existence of subcontrol areas, operated by transmission owners, will create potential conflicts over the basis for and determination of available transfer capability (ATC), curtailments, scheduling, resolution of system emergencies, and other important ISO decisions.

- **More, Not Less, Generation Under AGC** -- The duplication of EMS systems and separate requirements for generation under automatic generation control (AGC) in each subcontrol area will be inefficient and likely result in a greater amount of generating capacity that must be controlled under AGC at additional cost to consumers.

- **Higher Transaction Costs** -- Separate subcontrol areas result in the "pancaking" of control area services and facilities. For example, aggregators will have to dispatch and schedule their resources across multiple subregions rather than a single consolidated control area, contributing to higher costs that must ultimately be borne by their customers. Aggregators and marketers will also have to meet higher total reserve obligations.

- **Lack of Comparability** -- An ISO with multiple subcontrol areas could result in potential comparability problems, particularly relating to the provision of ancillary services. A utility that maintains control over a subcontrol area has an incentive to provide ancillary services, such as load following and spinning reserves, to themselves at lower cost than to other users. There is also the additional potential for the overcollection of charges for imbalances from third-party users because those users will have less opportunity to offset their overages from some transactions with the under scheduling of other transactions. Where the transmission owner also controls the subcontrol area, that owner has the ability to schedule their transactions to avoid any imbalance penalties.

In a competitive electricity commodity business where operating margins are expected to be small, these and other advantages can become significant impediments to fair competition.

A final concern is the geography associated with the subcontrol areas. Under NERC guidelines, there are certain legitimate reasons for having subcontrol areas. However, the preservation of an existing utility's jurisdictional service territory and the market power conferred by such a franchise are not among them.

3. Minimum Necessary Generation Assets

The ISO's primary responsibility is reliability, which only requires the real-time, operational control of generation resources at the "margin." Therefore, an ISO needs to control only a relatively *de minimis* amount of generation necessary to operate the control area, and provide ancillary services to balance the system on a real-time basis. In addition, generating units that are operated on a "must-run" basis must have been designated as such by the ISO and subject to the ISO's control. Most generation need not be directly controlled by the ISO and can be self-scheduled by its owners to facilitate bilateral trades or bid into an exchange. Some poolco-type proposals would give to the ISO full control over all generation, and require the ISO to perform economic dispatch for the purpose of setting the pool "spot" price. The ISO should not attempt to design or operate a spot market in electric energy services.

4. Redispatch of Generation

An ISO should not dispatch generation according to economic merit -- this should be left to the generation owners in the competitive marketplace -- but should be able to "redispatch" certain generators as necessary to maintain reliability or to manage power transfers across congested interfaces. Redispatching effectively overrides the merit order dispatch of each relevant generating unit as determined in the marketplace by economic forces alone. When feasible, the ISO should post on the OASIS its plan to redispatch generation and allow market participants to reschedule their transactions in order to optimize their respective market positions. This is one example of how a competitive industry structure can efficiently maintain reliability with market mechanisms.

In summary, it is desirable and necessary that an ISO control sufficient "wires" and transmission-related equipment to ensure reliable and nondiscriminatory access to the grid, but direct control of generation should be limited.

G. Other Authorities and Responsibilities of the ISO

1. Delegation or Outsourcing of an ISO's Operating Responsibilities

ISOs should use the same business practices private firms use to manage their business on a cost effective basis. "Outsourcing" is one such practice. However, the unique nature of the ISO requires that there must be no conflict of interest among any of the parties involved.

The ISO, at its sole discretion, should be able to delegate back to transmission (or generation) owners secondary operational functions such as routine maintenance, or the opening and closing of breakers and switches, provided that any such delegation be in the form of a written agreement approved by the ISO Board.

When an ISO determines that a transmitting utility's right-of-way maintenance costs are excessively high compared with the costs incurred by other transmission owners, corrective action should be required to bring those costs under control. Similarly, the ISO may contract with any competent third party to carry out some or all of its responsibilities, provided that such contractor is selected through a competitive-procurement process.

2. MAINTENANCE SCHEDULING

The ISO should develop, implement, and amend as necessary the maintenance plan for ISO transmission facilities, including transmission-related facilities, and all generation controlled by the ISO in a manner that promotes reliability and cost effectiveness. The ISO should also be informed of the maintenance schedules of major generating facilities that are not subject to its direct control. This is necessary to avoid reliability problems and any potential exercise of market power.

3. EMERGENCY CONDITIONS

The ISO should be authorized to take whatever actions are necessary to remedy, on a real-time basis, any emergency transmission-operations problem, including the opening or closing of circuit breakers, removing a line or lines from service, curtailing certain transactions, and/or scheduling emergency power from one area to another. These actions are straightforward and guidelines have been established by NERC. The ISO should also direct the restoration of normal service after an emergency condition has been rectified at both the local and regional levels.

A problem only emerges if these responsibilities are shared between a weak ISO and two or more subcontrol areas that remain under transmission owner operation. Unless this can be avoided, it will be necessary to negotiate who is responsible for taking what actions during an emergency, who will decide when the action is to be taken, and which and when system restoration procedures should begin. It will then be necessary to understand what each potential action and procedure is and what accounting for associated costs is required. Such problems can be avoided by ensuring that the ISO has adequate operational control of the necessary facilities.

4. ANCILLARY SERVICES

The ISO should establish standards for the provision of ancillary services by the ISO in compliance with FERC rules and regulations. Generally, ancillary services should be procured by the ISO, or offered to ISO users who elect to self-provide such services, on a competitive basis. Those services should be posted on the OASIS and offered at the ISO's cost of service. The ancillary services defined by FERC are:

- **Scheduling, System Control and Dispatch Service**
- **Reactive Supply and Voltage Control from Generation Sources Service**
- **Regulation and Frequency Response Service**
- **Energy Imbalance Service**
- **Operating Reserve -- Spinning Reserve Service**
- **Operating Reserve -- Supplemental Reserve Service**

These services and their definitions are based on a subset of "interconnected operations services" ("IOS") developed by NERC. Other, related services exist, but they are more appropriately provided for in separate service agreements or other contractual arrangements between market participants (*e.g.*, dynamic scheduling and loss compensation). The rates, terms, and conditions for each ancillary service should be determined on a case-by-case basis, at the time FERC adjudicates the ISO's grid-wide open-access tariff.

H. MARKET SUPPORT

The purpose of the market support function is to facilitate access to the transmission system by calculating available transfer capability or ATC, making that information available to all market participants by posting it on the ISO OASIS, and promptly responding to service requests. The ISO will redispatch generation, when necessary, to relieve transmission constraints and/or accommodate transmission service requests. It is not the ISO's responsibility to *make* the market, to guarantee market outcomes according to preconceived technical rules or guidelines, or to interfere in any other way such as to prevent market clearing prices from reflecting the combined behaviors of buyers, sellers, and independent market intermediaries. Key market support functions include:

- **Calculate and Post Available Transfer Capability (ATC)** -- The ISO should be responsible for obtaining the data necessary to effectively calculate ATC. The amount of ATC posted should be the amount that the ISO expects, in good faith, to be available on a specific interconnection or path in a specific direction, based on sound engineering analysis and other information.

- **Process Transmission Service Requests** -- The ISO should review and approve schedules, administer the grid-wise tariff, coordinate ancillary services (*e.g.*, specify and track required services, verify that services are in place, and notify affected parties); and perform redispatch and generation curtailment procedures to alleviate transmission constraints. The ISO should post its intention to redispatch generation and the expected transmission surcharges associated with the redispatch, and allow market participants to reschedule any or all of their transactions.

- **Operate the ISO OASIS** -- The ISO should maintain the ISO OASIS according to, but not limited to, FERC rules and guidelines. The ISO OASIS will provide information and services that will facilitate participation in the electricity commodity marketplace. This includes: the posting of each service provider's product offerings and prices (including transmission tariff information); informal communications; and accounting, auditing, and energy marketing tools. Pre-existing, "grandfathered" contracts for transmissio services should also be posted.

- **Post Ancillary Services** -- Providers of ancillary services should be able to post on the ISO OASIS the prices, terms and conditions associated with any services they offer to any users of the ISO grid. Transmission service providers (and others) should also provide a downloadable file of their complete tariffs in a generally accepted format. The ISO may provide some ancillary services as the provider of last resort. These services should be offered at the ISO's cost.

- **Trading Arrangements** -- Buyers and sellers of services offered on the ISO OASIS should be able to conduct their trading in one of two modes, depending upon the characteristics of the pending transaction:

  (1) **Brokerage System** -- Any eligible participant should be able to enter buy and sell quotes for multiple types of transmission service transactions. The OASIS system should automatically match quotes meeting the established criteria. The system should verify ATC prior to establishing the match.

  (2) **Bulletin Board/Informal Chat Sessions** -- Contact names and phone numbers of parties offering to buy or sell services should be provided to facilitate both off-line negotiation of transmission service transactions, and secure methods for on-line negotiation. Once both parties have agreed to a sale, the transaction should be forwarded to the ISO for approval.

- **Secondary Market for Transmission Services** -- Transmission users wishing to market transmission services already purchased or reserved from transmission providers should be allowed to post offers or requests for bids on the ISO OASIS. The ISO should not offer these services to the exclusion of their availability by market intermediaries.

- **Administer Transaction Accounting** -- The ISO should have the responsibility for administrating the procedures for settling accounts after any transaction through the ISO has been completed. This includes providing loss calculations, maintaining historical data for auditing purposes, allocating redispatch costs, and providing miscellaneous accounting information. Specifically:

  (1) **Losses** -- The ISO calculates the losses associated with each transaction schedule and determines which entities provided the losses. Settlements may occur on a daily, weekly, monthly, or quarterly basis at the discretion of the customer, subject to ISO billing procedures.

  (2) **Energy Accounting** -- The ISO notifies entities within the control area of their receipts and deliveries. Periodic summaries of approved, scheduled transactions will be made available to all service providers and customers.

  (3) **Historical Data for Audits** -- The ISO maintains data necessary to perform a transaction audit. The ISO OASIS will support the audit function by recording each logged transaction file in a relational database. Commercially sensitive information will be secured until a standard release period elapses after which all audit information is available for scrutiny.

  (4) **Allocation of Redispatching Costs** -- The ISO reallocates the cost of redispatch to multiple users of transmission capacity when more than one transaction benefits from redispatch operations. Such cost allocations will be performed according to predetermined ISO guidelines.

I. GENERATOR RESPONSIBILITIES

Each generating company should submit to the ISO its unit-commitment schedules for ISO review and approval. ISOs that include power exchanges usually combine this requirement with a bidding scheme for day-ahead or hour-ahead markets. In addition, each generating and transmission company operating within the ISO control area should submit maintenance schedules to the ISO for review and approval. ISO approval/disapproval should be binding, but may be appealed to the ISO's dispute resolution process.

J. POWER EXCHANGES

Some ISO proposals include provisions for a power exchange. A power exchange is a centralized pool which solicits bids for a predetermined and structured power market, *e.g.*, hour-ahead and day-ahead energy markets, or markets for ancillary services, establishes a market clearing price, and sells at that price. The market clearing price, which in some power exchange proposals is called the "spot" price, is set by an auction process. Different types of auctions are possible, each having different effects on the bidding behavior of the potential bidders, and the outcome of the auction. Some power exchange proposals are symptomatic of mistrust in markets based solely on bilateral trades, and should be avoided. At their extreme -- such as the ill-conceived "poolco" proposal -- the pool displaces the market.

K. LONG-TERM TRANSMISSION SYSTEM PLANNING

The ISO should be responsible for the long-term planning of the ISO grid on an on-going basis. This planning function must ensure that the ISO grid is adequately maintained and expanded to accommodate growth and other market changes. In addition, the ISO should be a party to any *ad hoc*, coordinated, regional (or state) planning committee, commission, or collaborative intended to achieve planning objectives involving two or more ISO areas.

Once the ISO determines that new or enhanced facilities are needed, it should seek the cooperation of existing transmission owners to develop and complete the project on an expeditious basis. However, new entities should not be denied the opportunity to build new facilities or to enhance existing facilities. Where more than one entity is interested in developing a project, the project should be subject to competitive bidding procedures. If no existing party is willing to develop a new or enhanced facility, the ISO should take the necessary steps to form a new, independent corporate entity to bear the responsibility.

ISO planning responsibilities should include the review of and evaluation of forecasted peak demands, generating capabilities, and transmission capacity. Case studies should be performed assessing future transfer capabilities, interconnection reliability, and interconnection capabilities. This process will assure that the planning criteria are met to maintain reliability and that enhancements or new transmission facilities included in the plans are necessary and adequate. Specific planning functions include:

- **Coordinate Long-range Planning** -- The ISO should prepare, on a regular basis, various reliability and market assessments of future transmission operations,

including an annual report describing projected transmission system operations and requirements during the next ten-year period. All recommendations for new facilities or enhancements to existing facilities should be posted on the ISO OASIS.

- **Long-term ATC** -- The ISO should annually produce a report for the next five or ten years estimating the ATC of all major transmission paths within the ISO, and all interconnections with neighboring ISOs.

- **Maintain Load Flow Data** -- On a regular basis, as necessary, the ISO should prepare a completely solved load flow and data set containing the appropriate modeling for its transmission system including any generation which uses, or may use, the ISO grid.

- **Evaluate Transmission Constraints and Disturbances** -- On a regular basis, the ISO should produce a report on important ISO grid constraints and disturbances, and recommend necessary changes in ISO operational practices and guidelines, physical enhancements, or the expansion of transmission facilities so as to relieve the constraints.

- **Capacity Reserve Report** -- The ISO should evaluate annual forecasted peak demands and installed capacity for the current and future years (*e.g.*, five to ten years) and report any expected changes to the ISO grid's reserve requirements. All planning reports should be publicly available.

L. TRANSMISSION PRICING AND CONGESTION MANAGEMENT

1. TRANSMISSION RATES AND TARIFF STRUCTURE

Transmission services offered by an ISO should accomplish the following objectives:

- The rates, terms, and conditions for transmission services should reflect the actual costs of providing those services, and recover the revenue requirement in order to provide transmission owners with a reasonable rate of return on all prudently incurred investments that are used and useful.

- The tariff structure for transmission services should promote:

  - Robust competition in generation services;

  - The efficient use of the system by encouraging -- in the short run -- greater use of under-utilized facilities and less use of over-utilized facilities;

  - The efficient siting of new generation facilities such as to reduce the long-term costs of *delivered electricity* to ultimate consumers; and

  - The efficient planning and expansion of the transmission grid.

- All users -- particularly end-use customers -- should be given efficient economic incentives to reduce their loadings during high-cost peak demand periods when transmission facilities are most congested. An important tool for congestion management is to eliminate congestion created by inefficient or inappropriate price signals for generation services.

Rates and tariff structure should also be designed to reflect certain time-tested principles of price regulation. These principles include: simplicity, understandability, public acceptability, and feasibility of application, among others.[5]

Based on 1994 costs, industry-wide generation costs accounted for 60% of total embedded costs; transmission-related costs were only 11%. Almost the same disparity exists with new investments. Annual industry-wide investments from 1988 through 1992 were 40% for generation and only 16% for transmission. Certainly, from a consumer perspective, promoting an efficient generation market should have a greater dollar impact than promoting the efficient use and expansion of transmission independent of its affect on generation transactions. Therefore, as a priority, transmission pricing should first facilitate more robust competition in generation, and only second, improve the efficiency of transmission services themselves *provided that competition in generation is firmly established.*[6]

The laws of physics do not comfortably accommodate a transmission tariff structure based on capacity rights or distance, no more than the often discredited "contract path" method did in the past. All users of ISO transmission services are entitled to the same service regardless of location. Nonetheless, some form of tariff is necessary and therefore a "second best" solution dictates the need for an "acceptable engineering fiction." Within an ISO grid, an "acceptable engineering fiction" would allow one or at most, a few, transmission zones to be defined -- on a case-specific basis -- which are relatively congestion-free within, and where the zonal boundaries are defined along known congestion interfaces. Such zonal boundaries should be limited to interfaces which experience chronic congested conditions and for which new construction to relieve the congestion is not forthcoming. Absent this requirement, zonal boundaries must not be configured to conform with transmission owners' traditional service territories. The establishment of separate pricing "zones" within the ISO grid is not justified unless congestion conditions are extremely severe and unduly penalize one group of market participants at the expense of another. The intent is that both the ISO

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[5]The well-known eight criteria championed by Bonbright are relevant: (1) The related "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application; (2) Freedom from controversies as to proper interpretation; (3) Effectiveness in yielding total revenue requirements under the fair-return standard; (4) Revenue stability from year to year; (5) Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers; (6) Fairness of the specific rates in the apportionment of the total costs of service among the different consumers; (7) Avoidance of "undue discrimination" in rate relationships; and (8) Efficiency of the rate classes and rate blocks in discouraging wasteful use of the service while promoting all justified types and amounts of use in the control of the total amounts of service supplied by the company, and in the control of the relative uses of alternative service (on-peak versus off-peak electricity). CHARLES F. PHILLIPS, JR. THE REGULATION OF PUBLIC UTILITIES: THEORY AND PRACTICE 380-381 (1985).

[6]This requirement is generally consistent with economic theory which states that efficiencies are optimized simultaneously across several product and service lines, not on a piece-meal basis, *i.e.*, any attempt to "piece-wise" optimize generation and transmission will not guarantee efficient results. In more practical terms, the dog should wag the tail, not the other way around.

grid and any intra-grid zones be geographically large -- to allow the averaging of most or all congestion costs across the largest possible customer base -- but not be so large as to compromise reliability or efficient market operation.[7]

Transmission users throughout the ISO grid should be charged an embedded cost, postage-stamp rate for load-based network service, plus a separate charge for losses.[8] The establishment of a postage-stamp rate is, in effect, an access charge for use of the entire ISO grid. In addition, congestion adders would apply but only during periods of congestion. This maximizes generation efficiencies in the market by removing most capital costs of transmission from transactions involving generation services.[9] Otherwise, some arbitrary (or deliberately biased) allocation of transmission fixed costs will make or break a deal involving generation sales. The rates for transmission services should be provided in advance of the actual transaction and not assessed retroactively.

2. Pricing Across Congested Transmission Interfaces

An important responsibility of an ISO is to relieve transmission congestion by planning for enhancements or the additions of new facilities. It is not sufficient to price transmission services in order to discourage use across a congested interface -- even though usage must be fairly allocated, and restricted, until the capacity constraint has been removed. The priority must be the removal or mitigation of the constraint, not solely a pricing mechanism that might perpetuate it.[10]

The costs associated with most occurrences of congestion (*i.e.,* sporadic congestion), wherever located, should be averaged across all users in the postage-stamp rate. The rates for usage across a valid zonal boundary should be established on a *transaction-specific basis* so as: (1) to recover the additional revenue requirement associated with any redispatch costs, and (2) to create an incentive to relieve the congestion. The costs of new construction and enhancements, to relieve transmission congestion or to meet the needs of load growth, should be recovered on a rolled-in embedded cost basis. New construction/enhancements should help to further consolidate and eliminate the zones.

For each congested interface managed by an ISO, the ISO would establish a congestion adder, which would be in addition to the postage-stamp rate and charges for losses, for service across the interface based on actual expected redispatch costs. The redispatch costs and adders would be posted

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[7]In establishing an ISO in which multiple utility service territories (and their corresponding control areas) are merged, the postage-stamp rate would embed the revenue requirements of each transmitting utility on a weighted average basis. This eliminates the need to define separate access charges (so-called "license plate" rates) for intra-grid zones that conform to the old control areas.

[8]Network service -- which is based on the user's load -- assures that transmission access rights are assigned to transmission users (or "loads"), rather than the suppliers. This diminishes the opportunities for suppliers to acquire and maintain market power.

[9]Users requesting "wheeling-through" or "wheeling-out" services from an ISO pay a point-to-point transmission charge. These revenues will offset the costs for all network users.

[10]Some congestion pricing proposals would allow transmission owners to receive "rents" in excess of true cost of service. These revenues, which are based on replacement costs, would discourage transmission owners from incurring new investments to expand transmission capacity.

on the ISO OASIS and both suppliers and end-use customers would be given the opportunity to modify their transactions if it is in their economic best interest to do so. For example, large end-use customers would have an incentive to sell options on their firm needs during the congestion periods. The ISO could select the options with the lowest call prices as one tool for minimizing congestion. Where feasible, generators would also be allowed to bid to provide the redispatch services. In effect, competition would exist between suppliers willing to supply generation and end users willing to curtail service.

3. Access to Congested Interfaces

Until a congested interface is relieved, access across the interface may have to be rationed among potential users. Two methods for rationing access are possible: (1) the ISO establishes a protocol for assigning priority rights of access, and (2) access in the form of tradable capacity rights is auctioned. In either case, the rights of existing users subject to contracts that pre-date the Energy Policy Act of 1992 may need to be grandfathered until the expiration of any applicable contracts that secured those rights.[11] However, the "rights" of potential future users of congested interfaces must also be recognized. Retail consumers do not yet have direct access to transmission facilities, but that is changing. The ISO priority rights protocol or auction must not give existing or future wholesale entities the ability to lock up capacity for their own needs to the exclusion of other potential users. Existing users that seek incremental entitlement to any congested interface should be required to convert their old contracts to conform with ISO tariffs as a pre-condition to obtaining such access.

M. Conclusions

ELCON believes that, properly structured and implemented, ISOs can be essential components of a competitive electricity marketplace. Nonetheless, an ISO as envisioned in this document is an untested entity that is charged with important duties. Policymakers have a responsibility to ensure that the development and implementation of regional ISOs are not used as excuses to delay further advances in making the industry more competitive, *i.e.*, by delaying the introduction of retail customer choice.

Given that an ISO is, by design, a monopoly service, policymakers and market participants also must ensure that the long-term inefficiencies inherent in many monopolies are not duplicated by this new entity. This requires careful attention to the specific responsibilities assigned to the ISO and a requirement that no ISO be granted an exclusive franchise for any service for which a competitive market will readily provide. If something better is possible, it should be allowed and encouraged.

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[11]These rights should not be extended indefinitely by the use of so-called "evergreen" clauses. Such clauses typically allow a contract to automatically rollover for a preset length of time unless one or both parties agree to terminate it. These contracts should be made public and posted on OASIS.

DEFINITIONS[12]

Adequacy	Adequacy is a component of **reliability** that deals with the ability of the system to supply the aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and unscheduled outages of system facilities.
Ancillary Services	Any service provided in support of the transmission **grid**. Some ancillary services such as **reactive power** support and **frequency regulation** are required to regulate the power system. Others such as **operating reserves** are required to provide reserve capabilities to help sustain the power system in the event of a major system disturbance or loss of critical facilities. Both regulation and reserve type ancillary services can typically be supplied by generators, and in some cases, by entities with specialized control equipment. FERC has defined six classes of ancillary services in *Order 888* (see page 14 of this *Profile*). **NERC** has developed a somewhat broader class of services called interconnected operations services (IOS). FERC's ancillary services are those NERC IOS services which FERC requires transmission providers to include in their open-access transmission tariffs. FERC believes that the other IOS services -- *e.g.*, losses, dynamic scheduling, and backup generation services -- are more appropriately provided for in a separate service agreement or other contractual arrangement. These other IOS services can be offered to user on a competitive basis. FERC's six ancillary services may also be offered on a competitive basis but some must be provided at the **control area** level under the direct supervision of the system operator or ISO.
Available Transfer Capability (ATC)	A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above the already committed uses, as defined by FERC.
Area Control Error (ACE)	Area control error is the instantaneous difference between the actual and **scheduled interchange** (*i.e.*, movements of power) between the ISO **control area** and other control areas to which the ISO grid is directly connected, taking in account the effects of **frequency** bias.
Automatic Generation Control (AGC)	The control system by which a utility or the ISO continuously balances the generation sources and loads within its **control area** so as to maintain the desired net area **interconnection** power flow and thereby keep **frequency** constant. See **Frequency Regulation**.
Control Area	A control area is an electrical system, bounded by **interconnection** metering and telemetry. It continuously regulates, through **automatic**

[12]These definitions are adopted from several sources, including: NEW YORK PUBLIC SERVICE COMMISSION, CASE N°. 94-E-0952, "GLOSSARY," RESTRUCTURING NEW YORK'S ELECTRIC INDUSTRY: ALTERNATIVE MODELS AND APPROACHES, SEPTEMBER 1995; U.S. CONGRESS, OFFICE OF TECHNOLOGY ASSESSMENT, ELECTRIC POWER WHEELING AND DEALING: TECHNOLOGICAL CONSIDERATIONS FOR INCREASING COMPETITION, OTA-E-409 (WASHINGTON, DC: U.S. GOVERNMENT PRINTING OFFICE, MAY 1989); and FERC ORDER 888.

generation control (AGC), generation within its boundaries, and **scheduled interchange** back and forth across the **interties**, to match its system load while contributing to **frequency regulation** of the interconnection. In 1989, there were about 99 control areas in the Eastern Interconnection, about 34 in the Western Interconnection, and 10 in ERCOT, the Texas Interconnection.

Control Center

Traditionally, the facility from which instructions and signals are issued for physically controlling the bulk electric system and the distribution system. An ISO control center may not initially include the local distribution functions.

Control Performance Criteria

NERC and **regional reliability council (RRC)** standards of minimum **control area** performance as measured from the **ACE** values and other operating parameters.

Energy Management System (EMS)

An array of computer hardware, software, and communications equipment which constantly monitors conditions throughout an area, including loads, generation and line flows, and communications signals to control generation and transmission equipment.

Frequency

Refers to the number of times per second that the voltage of an alternating current (AC) system -- such as the three **interconnections** serving the lower 48 states -- varies from positive polarity to negative polarity and back to positive polarity. Each such variation is a "cycle," with frequency usually measured in cycles per second or Hertz (Hz). Each of the three interconnections operate at 60 Hz; however, they are not synchronized with each other.

Frequency Regulation

An ancillary service usually provided at the **control area** level to maintain the **frequency** of the **interconnection**, usually by means of **automatic generation control** (AGC). This service is also called **load following** because someone must supply extra generating capacity -- "regulating margin" -- to follow the moment-to-moment variations in the load located in the control area. Load following is important because if demand exceeded supply, the frequency drops, causing generators to slow down; if supply exceeds demand, the frequency increases, causing generators to speed up. Both situations could result in an unstable situation which could lead to a widespread outage. See **Imbalances**.

Grid

The interconnected transmission network, generally, of any size or portion thereof. A grid may be an **interconnection**, a **control area**, or a local network, depending upon the context. A.k.a. the "wires."

Imbalances

Energy imbalance service -- an **ancillary service** -- supplies any hourly mismatch between a transmission customer's energy supply and the load being served within the **control area**. In contrast, **frequency regulation** -- another ancillary service -- corrects for instantaneous variations between the customer's resources and loads, even if over an hour these variations even out and require no net energy to be supplied.

Inadvertent Interchange

Inadvertent flows are the difference between the quantity of energy scheduled for delivery and the quantity of energy actually delivered pursuant to such schedule. Inadvertent interchange is the difference between scheduled and actual flows on the **interties** connecting two or more **control areas**. A.k.a., loop flows.

Interconnection

An interconnection is any transmission **grid** subject to **synchronous operation**. In the United States and Canada, there are four interconnections: the Texas Interconnection (or ERCOT), the Eastern Interconnection, the Western Interconnection (or WSCC), and the Québec Interconnection.

Interties

Interties are transmission facilities that interconnect adjacent **control areas**. These lines are typically metered and controlled with telemetry. Power flows on the interties are scheduled -- called **scheduled interchange** -- by the respective control areas.

Load Following

See **Frequency Regulation**.

Must-run Generation

Generating facilities that must be running to provide instant compatibility to respond to base and changing loads served. Transmission constraints often create the need for must-run units, *i.e.*, available generating capacity elsewhere cannot be wheeled in and therefore local generators must be run to meet load.

North American Electric Reliability Council (NERC)

The North American Electric Reliability Council (NERC) is the principle organization for coordinating, promoting, enforcing, and communicating about **reliability** for North America's electric systems. NERC was formed in 1968 in the aftermath of the November 9, 1965 Blackout that affected the Northeast United States and Ontario, Canada. As presently structured, NERC is a not-for-profit corporation whose owners are ten **regional reliability councils (RRCs)**. The members of the RRCs are electric utilities and exempt wholesale generators. NERC establishes operating and planning policies, principles, criteria, standards, and guides to ensure electric system reliability. It also reviews the reliability of existing and planned generation and transmission systems, and critiques past electric system disturbances for lessons learned, and monitors and -- beginning on January 6, 1997 -- *enforces* the compliance and conformance to its standards and guides.

Open-Access Same-Time Information System (OASIS)

The information system referred to in Part 37 of the Federal Energy Regulatory Commission's (FERC) regulations. This regulation requires transmission owners to create or participate in an OASIS that provides open-access transmission customers information, on the Internet, about **available transfer capability (ATC)**; the rates, terms, and conditions of transmission service, including **ancillary service**; and other commercially important data and information that will enable the users to obtain such services on a nondiscriminatory basis.

Operating Reserves

FERC defines two separate kinds of operating reserves: (1) spinning reserve and (2) supplemental reserve services. Operating reserve is extra generation available to serve load in case there is an unplanned event such as loss of generation. Spinning reserve is provided by generating

units that are on-line and loaded at less than maximum output. They are available to serve load immediately in an unexpected contingency. Supplemental reserve is generating capacity that is not available instantaneously, but rather within a short period (usually ten minutes). Supplemental reserve capacity can be provided by generating units that are on-line by unloaded, by quick-start generation, and by customer-interrupted load.

Reactive Power

There are two forms of power: (1) real power, which is what most people think of when they use "electricity;" and (2) reactive power which is consumed by induction motors, power system equipment, and heavily loaded lines. Reactive power is an **ancillary service**; it is not consumed directly by end users, but must be provided to, or absorbed from, the system to maintain **voltage stability**. For example, reactive power or "VARs" must be added to the system when the voltage drops below specified levels. A.k.a., reactive supply and voltage control.

Regional Reliability Councils (RRCs)

Like **NERC**, the regional reliability councils (RRCs) were formed in the late 1960s in response to the Northeast Blackout of 1965. There are ten RRCs covering continental United States, Canada, and portions of Mexico. The RRCs coordinate planning and operations and exchange information on electricity supply, demand, and **reliability**. The RRCs provide NERC with annual and seasonal assessments of electricity supply and the factors affecting **adequacy** and **security**. Historically, membership in an RRC was voluntary, but most RRCs limited full voting membership to utilities that own generation or transmission that can have a significant impact on regional operations.

Reliability

Reliability has two components: **adequacy** and **security**. Adequacy is the ability of the system to supply the aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is defined below. It is necessary to have rules by which to plan and operate the interconnected grid to achieve adequate reliability. NERC has rules called Planning Policies and Operating Policies to fulfill this requirement.

Scheduled Interchange

Scheduled interchange are power flows that are scheduled across the **interties** connecting adjacent **control areas**.

Scheduling

The action by the system operator or transmission provider to schedule power flows across a specific **intertie**.

Security

Security is the ability of the grid to withstand sudden disturbances such as short circuits or the unanticipated outage of a system facility (*e.g.*, a generating unit or a transmission line)

Supervisory Control and Data Acquisition (SCADA)

Telecommunications systems by which data from the electrical grid are transmitted to the **control center**, and commands from the control center are transmitted to the various power system facilities.

Synchronism

The process of operating all alternating current (AC) generating units connected to the same electrical system -- or **interconnection** -- at the same **frequency**, and in phase with each other, with voltages having the

same polarity at every instance. "In phase" means that the power from different generators change polarity at precisely the same rate, *i.e.*, from positive to negative and back to positive at the same time.

Synchronous Operation

A power system is in synchronous operation if all its connected synchronous machines are in synchronous operation with the alternating current network and with each other. By definition, all generators within an **interconnection** must be synchronous with each other and the grid. Each **control area** within an interconnection is responsible for monitoring **frequency** and correcting for any deviations.

System Control and Dispatch Service

An **ancillary service** which provides for confirmation and implementation of **scheduled interchange** with other **control areas**, including actions to ensure operational **security** during the interchange transaction.

Subcontrol Area

The metered boundary of any electrically established area comprising a subset of the entire ISO **control area** and for which the ISO or its designee measures and is responsible for meeting all load serving and NERC/ACE **control performance criteria**. A subcontrol area may be an existing NERC certified control area operated by a utility in the old regulatory regime.

Transmission Path

A transmission path is a set of transmission facilities used in effecting a power transfer and is defined by the generation (source) and the load demand (sink) being served. The source and sink are located in defined "zones" which will be used to properly model the transfer in a load flow study or simulation.

Unit Commitment

The process of determining which units should be operated each day to meet the daily load of the system.

Unit Commitment Schedule

A list of generating units, including the dispatch parameters of each, which the owners or operators of those units proposes to run the next day.

Voltage Stability

Condition of a power system in which the voltage level is maintained within acceptable and predetermined limits. Voltage stability is determined by the characteristics of the network, the generation on line, the amount and location of reactive sources, and the operating procedures used. See **Frequency Regulation**.

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