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POWER SYSTEM CONTROL

An electric utility has the responsibility of generating electricity and delivering it on demand to a remote customer. If an electric utility consisted of one generating plant connected to one customer by one transmission path, then the control of the system would be trivial. However, today's modern electric utility consists of multiple, geographically spaced sources of electric power generation, interconnected by a spider-web-like system of transmission and distribution networks to ensure efficient delivery of electricity to its customers. For example, one large electric utility in the southeastern United States generated 156,000,000,000/kWh for about 11,000,000 people living and working in over a 120,000 square mile area in 1996. This large-scale system permits an electric utility to offer to its consumers a reliable product of high quality and economically priced. It also gives the utility the opportunity to be competitive with its resources while still being environmentally friendly. It is the role of power system control to ensure these benefits to the electric consumer and provider are realized. Therefore, power system control can be viewed as the problem of controlling the power output of each generator such that the combined power of the generators matches the combined power demand of the loads at the nominal frequency while meeting a variety of economic, operational, and environmental constraints.

The following explanation of power system control is based on the traditional approach of the vertically integrated utility. However, the electric supply industry is in a rapid period of flux. Functions previously in the exclusive domain of the vertically integrated utility are now being performed by nonutility marketers and independent system operators (*ISO*s). The traditional regulated monopoly environment with exclusive franchise territories and a mandated obligation to serve is shifting rapidly toward an open access, market-based system with flexible boundaries and only economic obligations. Today wholesale customers have open access. In the future, retail access, in some form or fashion, will probably be available to most customers. This will radically change (and complicate) the power system control process from what is explained herein. However, the fundamental premise of power system control will not change—generation will still be required to meet load.

The Control Problem

Control of any process requires there be variables that can be sensed to determine the state of the process and actuators that can be controlled to change the state of the system to a new state. This normally happens within the context of a closed loop, or feedback, control system. Figure 1 shows a typical feedback control system. In power system control, some of the variables of importance are system frequency, voltage, and power flow (real and reactive). For a thermal unit (e.g., coal-fired boiler) the actuators would be the turbine governor and steam admission valves that adjust output power. Another actuator could be the settings on the generator's exciter which change the output voltage of the generator. In Fig. 1 the Plant represents the interconnected power system (generators, transmission lines, etc.). Information about system frequency, power flows, or voltage may be sensed and fed back to the referenced system input. An error is calculated between the actual and expected

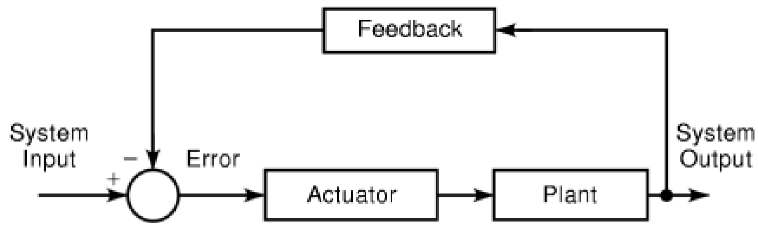

Fig. 1. Block diagram of a typical feedback control system.

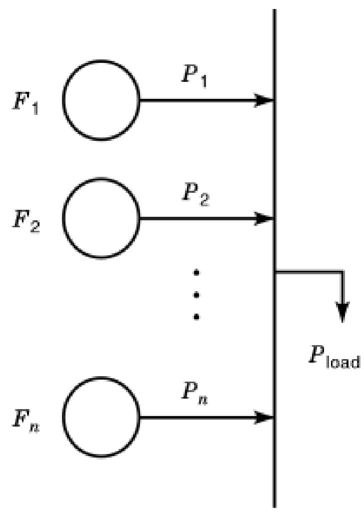

Fig. 2. Multiple generators supplying a system load.

system variables and this is translated into a control action via the actuator. With the control action initiated by the actuator, the plant moves to a new state or operating point and the cycle continues.

Figure 2 will help to illustrate the control problem in modern power systems. The principal function of the power system control unit is to adjust the output of the available generators to meet the system load while meeting all constraints imposed by engineering design, regulatory, and financial considerations. This desire can be expressed as

$$P_1 + P_2 + \cdots + P_n = \sum_{i=1}^{n} P_i = P_{\text{load}} \qquad (1)$$

In general, a utility will have a large number of generating units of various size (MW capacity) and type (thermal, hydroelectric, etc.) available to meet its customers demand or load. These units are operated in synchronism which means they all operate at the same frequency and will all attempt to respond to any change in load.

One of the first control problems is the effective operation of machines in parallel. Most people think of electricity as being a constant frequency (50 Hz or 60 Hz) commodity. However, a truly constant frequency requires a generator to operate at a constant speed. This constant frequency control is an impossible task to perform on an interconnected power system such as that shown in Fig. 2. To enable efficient operation of parallel generators a speed governor must be used on the turbines of the various units. This turbine governor permits the units to depart from the nominal system frequency in order to participate in effective load sharing.

Governor Control System

If Eq. (1) were satisfied all of the time, then there would be no need for a governor control system. However, loads change according to the needs of the consumers and are strongly dependent on weather patterns and work day schedules. Since system load is a dynamic quantity that cannot be precisely predicted, the governor control systems are often reacting to correct for the mismatch of generation to load. The generating units with governors are acting to ensure the synchronous network can withstand these imbalances without collapsing. Therefore, the governor control system provides primary frequency control to the synchronous network.

The result of this mismatch of generation to load is a frequency deviation from the nominal value. Under-generation or an increase in load will cause the system frequency to drop, while over-generation or a decrease in load will cause the frequency to rise. Equipment constraints limit the maximum frequency deviation from nominal values. Larger deviations lead to problems such as unacceptable vibration levels in steam turbine blades.

Governor control or primary frequency control is a short time frame (seconds) mechanism for ensuring generation meets load. It will not, however, reset frequency to nominal after a disturbance. Automatic generation control (*AGC*) operating in the tie line bias mode provides secondary frequency control on the longer time frame (minutes) and is responsible for resetting system frequency to nominal after a sudden frequency shift has been arrested by the primary frequency control system. The two systems work together to provide stable operations at or near setpoint frequency on the synchronous network. In general, governor control can be thought of as the high-frequency component of frequency control and AGC as the low-frequency and/or bias component. They should be thought of as two different control loops.

The governor control system can be illustrated from Fig. 1. Considering a thermal unit, the system input is steam flow, the actuator controls a steam admission valve, the plant block represents the unit's prime mover (turbine), a device for measuring speed provides an input to the feedback loop, and the system output is mechanical power to the generator. The key to this control system is the speed-droop characteristic illustrated in Fig. 3. This characteristic shows that when there is a load increase on the generator that it will slow down. The slope of this characteristic, R, is referred to as the droop of the generator. Then R is the steady-state relationship between system frequency and generated power. Normally, all of the individual units should have their droop characteristics set to be about equal to minimize turbine governor oscillation. Also, with the same droop characteristic, each unit will share a change in system load in proportion to the individual unit's MW rating. Values for droop ideally range from 3 to 5%. However, according to a recent EPRI survey, the true measured droop characteristic of generators actually varied from 1% to 21% with 5% being the most common (1).

The governor control system is an integral controller with a feedback loop gain of R. Therefore, in operation when the speed of the turbine is sensed to be slowing down (i.e., the load on the machine has increased), the feedback loop will provide a signal to open the steam admission valve. When more steam is admitted into the turbine this will result in more mechanical power out of the turbine and eventually more electrical power out of the generator to serve the load increase. When an increase in speed occurs (load decreasing), the opposite actions will be taken and the electrical output of the generator will be decreased. More detailed analysis of the governor control system can be found in Refs. 2,3,4.

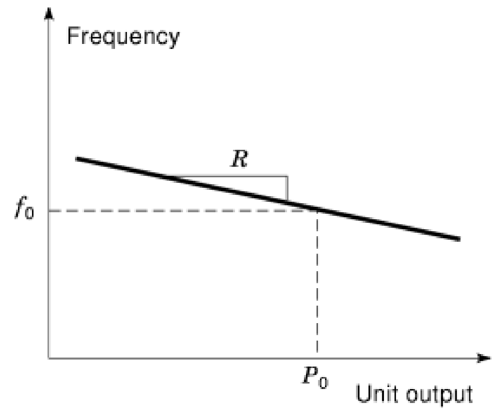

Fig. 3. Governor or speed-droop characteristic.

Control Areas and Supplementary Control

In general, electric utilities have operated within a franchised area. In other words, the local utility was responsible for meeting the load within a given geographical area. Although this is changing (see section entitled Deregulation), the classic view of a franchised service area is still useful in understanding the larger picture of supplementary control. The North American Electric Reliability Council (*NERC*) was formed in 1968 as an industry group responsible for setting guidelines to ensure reliable operation of the power system. NERC took the interconnected utilities in the United States and Canada and created four synchronously operated regions—the Eastern interconnection, the ERCOT interconnection, the Western interconnection, and the Quebec interconnection. These four interconnections were further divided into ten regional councils. And, finally the regions were divided into smaller operating units known as control areas. These control areas are responsible for ensuring the load within their geographic area of responsibility is reliably met.

A control area is defined by NERC as an electric system or systems, bounded by interconnection metering, and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas and contributing to frequency regulation of the interconnection (5). A control area meets its obligations of meeting its interchange schedule and contributing to frequency regulation by either generating power from units owned by utilities within the control area, by purchasing power from other sources, or by demand side management. One control area is connected to another via transmission lines that are specified as tie lines (see Fig. 4). It is on these tie lines that the interchange schedules are maintained.

Supplementary control is often referred to as either load frequency control (*LFC*) or automatic generation control (*AGC*). It differs from the governor control system in that it is on a time scale of several seconds where governor response is designed to be very nearly instantaneous. The primary objectives of AGC are: (1) to keep tie line interchanges as scheduled, (2) to maintain the system frequency at the nominal frequency (60 Hz in the USA), (3) to operate with security in mind (i.e., with sufficient energy reserve to accommodate disturbances in demand or generation), (4) to optimize economical operation, and (5) to maximize compliance with NERC guidelines.

Tie line bias control has typically been the control algorithm used for ensuring a control area meets its obligations to the grid. This control scheme attempts to maintain frequency support and interchange schedules by defining an area control error (*ACE*) term as follows

$$\mathrm{ACE} = (T_a - T_s) - 10B(F_a - F_s) \qquad (2)$$

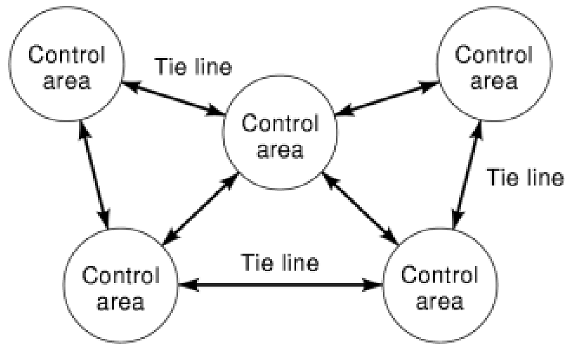

Fig. 4. Interconnected control areas.

where T_a is the measured tie line or interchange power flows in megawatts, T_s is the scheduled flow, F_a is the measured system frequency in hertz, F_s is the scheduled frequency, and B is a term representative of the control area's obligation to frequency support in MW/0.1 Hz. A more detailed explanation of tie line bias control is given in Ref. 6.

Figure 5 shows a block diagram of a supplementary control system. Note that it has metered tie line and frequency data which it uses to calculate a value for ACE. This metered data is normally filtered to provide a smoother function for control. A close examination of Eq. (2) shows that a positive value of ACE indicates that the control area is exporting more power than scheduled, while a negative ACE indicates the area is importing more than it has scheduled. A judicious examination of Eq. (2) can show to a control area whether the problem on the grid causing inadvertent tie line power flows is being caused by their control area or another one. This is an important factor in determining the new dispatch levels for your control area's generation. A simple method to help locate the source of the lost generation is to remember that if the signs of the two components of ACE are the same, then the problem is within the control area. If they differ, the problem is outside the control area.

The supplementary control cycle typically occurs on a 2 s to 6 s time frame. When the new dispatch levels are calculated, this information is transmitted to the plants by either a setpoint or pulse methodology. It can also be seen from Fig. 5 that supplementary control is typically a centralized control function; however, some work is on-going to make it more of a distributed control function (7). In fact, the new NERC Control Performance Standard is fully decomposable. A more complete description of an automatic generation control system can be seen in Ref. 8. Currently, supplementary control systems are primarily used to dispatch real power. Reactive power flows on the grid are recognized; however, the dispatching of units for reactive power flow is not a generally accepted practice.

Constrained Dispatch of Generation

Figure 5 indicates that the units available for dispatch are selected by the economic dispatch (*ED*) program. When units are dispatched to a new generation level there are a number of equality and inequality constraints that can be applied to the control problem. Equation (1) illustrates the simple equality constraint that generation must equal load. However, this simple constraint is complicated in reality when consideration is given to the fact that impedance of the transmission and distribution network are between the generation and load. Therefore, there are real power losses associated with the transmission network that must be added into the

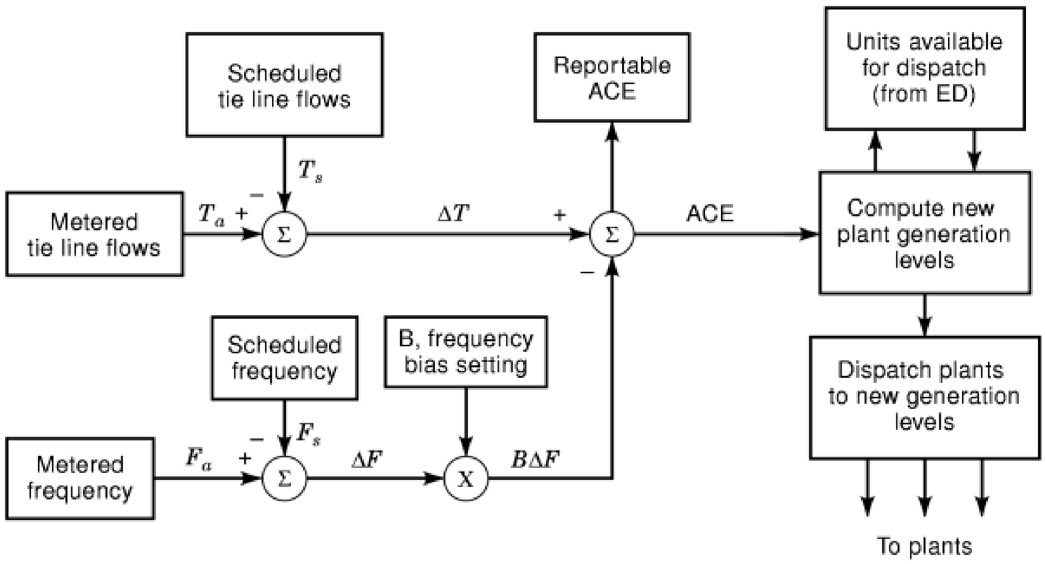

Fig. 5. Block diagram of a supplementary control system.

load term as

$$P_1 + P_2 + \cdots + P_n = \sum_{i=1}^{n} P_i = P_{\text{load}} + P_{\text{losses}} \tag{3}$$

or

$$P_{\text{load}} + P_{\text{losses}} - \sum_{i=1}^{n} P_i = 0 \tag{4}$$

There are also inequality terms such as minimum and maximum power outputs for the individual plants. Figure 2 also shows that each plant has a fuel cost associated with it (F_i). Therefore, it is possible to apply the principles of optimal control theory to this problem and develop an optimal dispatch level for the units subject to some defined constraint. Economic dispatch is the optimal control paradigm for finding the power output levels for multiple units while minimizing cost. This is described by two equations known as the coordination equations. One of them is Eq. (4) and the other is

$$\frac{\delta\lambda}{\delta P_i} = \frac{dF_i}{dP_i} - \lambda\left(1 - \frac{\delta P_{\text{losses}}}{\delta P_i}\right) = 0 \tag{5}$$

There are obviously many constraints that could be used in finding the optimal dispatch for a power system (e.g., environmental and hydro-thermal). References 3, 4, 9, and 10 are good sources.

Power Pools and Energy Management Systems

Transactions between interconnected utilities are simplified and optimized when the utilities belong to a power pool. Typically, a power pool central dispatch office would be responsible for setting up the interchanges between the members and for other administrative tasks. Power pools range from tight pools with strong central authority to loose pools with very little central coordination. The benefits and costs of pool operation vary widely depending upon the specifics of how the pool is set up. Advantages of belonging to a power pool include minimizing operating costs, performing a system-wide unit commitment, minimizing the reserves throughout the system, coordinating maintenance scheduling to minimize costs and maximize reliability, and maximize the benefits of emergency procedures (4). The disadvantages of belonging to a power pool include having to relinquish the right to engage in independent transactions outside of the pool, having to operate under the increased complexity added by the pool agreement and by other regulatory agencies, and paying operating and investment costs associated with the central dispatch office.

Power pools can operate as a brokerage house that arranges transactions among members or as a fully staffed central office with extensive telemetry data and computational equipment to calculate the optimum economical dispatch. The simplest form of brokerage house arrangement is the *bulletin board* scheme. In this approach the utility members post offers to sell or buy power at regular intervals. Members are free to contact each other and make direct transactions between them. More elaborate schemes require the members to sell and buy power to and from the pool, respectively. For example, the pool can average the sellers incremental costs and the buyers decremental costs and then redistribute the energy based on the average costs plus a constant percentage fee used to compensate those systems that provided transmission facilities.

Deregulation

As a regulated monopoly the electric utility industry has been the focus of a variety of regulators at all levels of government—the Federal Energy Regulatory Commission (*FERC*), the Rural Electrification Administration (*REA*), state public utility commissions, and even itself in the form of NERC. However, over the past two decades, in an attempt to introduce competitiveness into the electric utility industry, the US Congress and FERC have introduced a series of legislation and rules. This legislation and rule-making was aimed at opening the customer base within a utility's franchise area to competition. The Congress, in the Public Utility Regulatory Policies Act of 1978 (*PURPA*), began this attempt by confirming that the electric industry is an interstate industry subject to federal control in almost all dimensions of its regulated activities (11). The next major legislation was the Energy Policy Act of 1992. This act laid the legal groundwork for competitive wholesale markets and led to what has been referred to as the FERC's Mega-*NOPR* (Notice of Proposed Rule-Making). From the Mega-NOPR, two final orders were issued in 1996.

Order Number 888 stated that it was the goal of FERC to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the nation's electricity consumers. This was primarily to be accomplished by guaranteeing all generating systems open access to utility transmission networks. An important aspect of the order was that the reliability of the interconnected system was not to be compromised by the wholesale wheeling of power. To ensure this did not occur, the transmission provider was permitted to charge an access tariff to the transmission network that included ancillary services needed to maintain reliability and power quality at the transmission level.

Order Number 889 contained rules for establishing and governing an Open Access Same-time Information System (*OASIS*). This order requires each public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce to create or participate in an OASIS. The OASIS will provide open access transmission customers and potential open access transmission customers with information, provided by electronic means, about available transmission capacity, prices, and other information that will enable them to obtain open access nondiscriminatory transmission service. The latest information on FERC orders may be found at the NERC homepage (http://www.nerc.com/).

Facts

As the electric power transmission network grows in size and complexity the system response is more difficult to predict and control. The problem is aggravated as an increasing number of independent power producers (IPP) and non-utility generators (NUG) tie into the transmission system, and the seemingly inevitable ruling of "open access of transmission systems" by the Federal Government takes effect. A method of accurate, dependable control of the transmission system is needed if utilities are to provide reliable service in the future. To answer this challenge, the Electric Power Research Institute (EPRI) has launched a research project called Flexible AC Transmission Systems (FACTS).

First put forward in 1988, the FACTS program would utilize advances in silicon science to develop FACTS devices that can allow for compensation and control of system parameters much faster and more accurately than the mechanical versions in place today. These devices make use of thyristors as solid state switches to replace the slower, bulkier mechanical switches. FACTS devices would prove very useful in controlling the three parameters that determine the flow of power in a transmission system: the line impedance, the magnitude of the bus voltages, and the phase angle between the bus voltages.

The ideal result of the FACTS program is a power transmission system that employs many different FACTS compensators to eliminate problems such as loop flows, inefficient use of lines to thermal limits, and poor voltage regulation; all while improving power quality and system stability to transients and disturbances.

Loop Flows. One problem that the FACTS program deals with is that of loop flow on power systems. Loop flow is defined as the difference between scheduled and actual power flows on the interface between two systems. It is the flow of scheduled power from a generation area to a load through a transmission path where it is not intended. In other words, one utility ends up using another utility's system to transmit power without permission or payment. Loop flow occurs when there are many parallel paths from the generation site to the load center. The problem of loop flow from one utility to another is not currently addressed except by after the fact examination of scheduled transactions versus system conditions to see if in fact a loop flow situation was present during a given period. This is done because of the limited number of transactions that occur between utilities and the reasonably rare occurrence of serious loop flows that accompany them. However, when open access of transmission systems becomes a reality, the number of transactions on the system, and therefore the number of opportunities for loop flow to occur, will increase.

The problem of loop flows may be resolved by using FACTS devices to control the power flow between the possible paths to the load. The phase shifter appears to be the most effective compensator to avoid loop flows. The phase shifter is a device used to inject a series voltage into the transmission line at a controllable phase angle. This variable voltage source is used to inject a voltage of the appropriate magnitude and phase to improve the power transfer capability and the transient stability. Phase shifters can be used to decrease the flow of power in the nonscheduled path and thereby increase the flow in the scheduled primary path. Conventional phase shifters based on series transformers with mechanical tap changers are already in use in power systems but their operation is much slower in comparison to the expected response of FACTS-based phase shifters. The thyristor controlled phase shifter is expected to be able to control the phase angle quickly enough to increase the power transfer before the natural power swing occurs.

Although FACTS devices do have the potential to allow much finer control of power flows on the network than is currently available, they have not yet been widely utilized. This is largely due to their cost and unfamiliarity to system design and operations personnel. Another problem with FACTS devices is that there is no widely recognized methodology available at this time to determine in real time how they should be coordinated on a regional basis to optimize the network. In fact, there is no consensus as to what such an overall optimization function should be for the network. Much additional work needs to be done in this area before widespread use of FACTS devices will become evident.

Line Loading to Thermal Limits. One application of series capacitors is to use them to adjust line impedance to make full use of a line's thermal limits. For example, suppose there are two parallel transmission lines that compose the primary scheduled power path, or *corridor,* to a given load area. One of the lines is loaded to its thermal limits while the other has spare capacity. The power transfer of the two lines cannot be increased without exceeding the limit of the loaded line. Thyristor switched series capacitors may be used to decrease the impedance of the less loaded line, increasing the power flow on the line. In this manner the total power transfer over the two lines may be increased until both lines are at thermal limits. Phase shifters could also be used to control the power flow between the two lines by changing the phase angle. However, series capacitors appear to be better suited for this case because they serve the dual purpose of controlling power flow and generating substantial amounts of vars required by long transmission line corridors operating near thermal limits. Phase shifters, on the other hand, do not supply vars but consume them (which in turn must be supplied by additional shunt compensation). The thyristor switched series capacitors, then, are the more cost-effective choice. However, it must be remembered that NERC requires utilities to operate their systems such that all lines will be below their thermal limit after the first contingency.

The use of series capacitors to change the effective impedance of a transmission line brings up a topic in need of much further research—the effect of FACTS on protection schemes. The present relaying and protection schemes would certainly have to be modified to accommodate the presence of the system changing FACTS devices. One possible solution would make use of intelligent protection schemes capable of receiving information from the FACTS controllers about the status of the system and adapting the relay settings accordingly.

Voltage Regulation on Long Lines. The static var compensator (*SVC*) is a thyristor controlled shunt device primarily used to raise the voltage on long transmission lines. The SVC supports the voltage on these lines and, therefore, increases the power transfer. Studies have been done to determine the most effective placement of SVCs on a long line. The studies have shown that midpoint compensation has the most positive effect on voltage regulation and power transfer with the least negative effects on system dynamic performance (12). Although industry practice for voltage control is still dominated by switched capacitor banks, SVCs have shown potential for more widespread use in the future.

Emerging Power Control Issues

Power systems are equipped with numerous voltage controlling devices to ensure the system's voltage profile remains within predetermined limits for a variety of topological and loading conditions. As system load continues to increase without the construction of new sources of generation, the fear of a voltage collapse also increases. To aid in controlling the voltage profile of systems it will become more important in the future to not only have AGC control active power flow, but also reactive power flow.

Federal legislation will continue to impact the control of generation units primarily from an environmental viewpoint. Environmental dispatch will take on more of a supervisory role to classical AGC to ensure that the proper mix of units are operating to maintain a utility within environmental regulations (clean air and clean water) and such that the most judicious use of allowances is made. However, some federal legislation that mandates the use of alternative fuels for US Government automobile fleets and alternative fuel suppliers may have the effect of load leveling (due to the use of chargers at night) that the utility industry has sought for many years.

Demand side management (*DMS*) is another tool to assist in the balancing of load and generation. A smart DMS administered by AGC is an issue that needs to be further explored. This would permit AGC the option to drop load at the distribution level, in lieu of requesting additional expensive (economic or environmentally) generation, if it determines this is the best economical solution. Traditional DSM programs can also be rapidly supplemented with the use of market-driven programs such as real time pricing (*RTP*). Incorporating RTP into the unit commitment and AGC programs is another interesting problem.

The control of distributed generation is another emerging issue. As additional nonutility generators are added to the system (at both the transmission and distribution level) AGC will need to be able to properly dispatch utility owned units to meet load, provide voltage and frequency support, and overall system security. This will become a highly complex communication, control, and protection problem.

In today's rapidly changing electric utility industry, mergers are becoming commonplace, energy futures are being traded on the commodity exchange, independent power producers (IPPs) are coming on-line wherever the market looks promising, and power marketers are acting as the go-between for those with energy to sell and with those looking to buy. As these things transpire the traditional utility is looking to realign itself to remain competitive in this new market. To accomplish this, most utilities are restructuring. Separate generation companies, transmission companies, and distribution companies will become more prevalent in the future. The distribution company (i.e., load) will drive the market by seeking low-cost sources of energy from a variety of sources. This energy may be delivered via one or more transmission companies or it may be generated locally at the distribution level (therefore, avoiding transmission charges). The idea of building generation at the distribution level is attracting several entrepreneurs. This dispersed or distributed generation, as it is referred to, is normally smaller capacity generation, but it has the potential of becoming very important in system reliability.

Even the control structures are presently being debated. One scenario is a regional control area (RCA) consisting of a regional transmission group (*RTG*) and an associated regional system operator (*RSO*) in a control area whose boundaries may be based on existing NERC regions. The RSO, which may be nonutility owned (an independent system operator or *ISO*), would perform some or all of the functions of the existing pool control centers, depending on specific implementation. The primary function of the RSO would be to ensure comparable access and fair play among all transmission system stakeholders while maintaining the integrity and reliability of the network.

It is also important to consider the human side of power system operations. In the past, system operators were highly experienced and had intimate knowledge about the flow patterns and operational characteristics of their system. The operators of today, however, are confronted with significantly more complex systems characterized by rapid changes in stakeholders and flow patterns. Traditional relationships between stakeholders are changing and new stakeholders are being added at a breathtaking pace. For example, pool control center operators have traditionally been generation and transaction coordinators. They match power needs with available generation. This matching has been based primarily on cost and often ignored the use of security contingency tools (or utilized precalculated limits from transmission or operational planning studies) in decision making. These operators typically handled 10 to 15 bulk power transactions per hour and their primary concerns were those of pricing mechanisms and peculiarities of the generation resources and transactions.

However, now system operators must be prepared to operate in a more complex system, highly impacted (if not actively constrained) by the complexities of transmission system loading, open transmission access, IPPs, wholesale marketers, OASIS (real-time information networks), etc. In such a system most, if not all, generation control and transaction scheduling decisions will have to be screened for potential system reliability impacts. These will include both the traditional static constraints (thermal and voltage limits) as well as dynamic impacts (generation ramp rates and stability) and impacts on import and export capabilities.

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