WHAT IS SYSTEM CONTROL?

ERIC HIRST and BRENDAN KIRBY
Consulting in Electric-Industry Restructuring
Oak Ridge, Tennessee

Just as the aviation industry needs air-traffic controllers to manage the movement of airplanes for safety and commerce, so too, the electricity industry requires system operators. The electrical-system-control functions encompass a range of activities that support commercial transactions and maintain bulk-power reliability. As part of a project for the Edison Electric Institute, we examined the functions and costs of system control and the issues that need to be resolved in a restructured electricity industry (Hirst and Kirby 1998).

FUNCTIONS

The U.S. Federal Energy Regulatory Commission (FERC), in its Order No. 888, defined a *scheduling, system control, and dispatch service* that transmission providers must offer to transmission customers and that transmission customers must purchase from the transmission provider. The service includes the following functions: "interchange schedule confirmation and implementation with other control areas, including intermediary control areas that are providing transmission service [and] actions to ensure operational security during the interchange transaction."

FERC declined to include a separate accounting service in the open-access tariff. FERC decided that accounting for scheduling, system control, and dispatch is not separable from the other system-control functions and that accounting costs are likely to be small. Thus, FERC focused on the near-real-time commercial and security functions in its definition.

The Interconnected Operations Services (IOS) Working Group (1998) adopted a more expansive definition for what it called *system control*. It briefly defined the service as "the integration activities necessary to maintain a generation/demand balance, ensure transmission system security, and provide an appropriate level of emergency preparedness" (Exhibit 1). Thus, the Working Group included the real-time dispatch of generating units and the short-term (i.e., day-ahead) forecasting of system conditions in addition to the functions that FERC included in its definition.

Traditionally, these system-control functions were handled by the control-area operators at vertically integrated utilities. In large part because of FERC's Order Nos. 888 and 889, utilities have split these functions into two pieces: system-control (transmission) and commercial (generation) functions. Utilities differ in how this split is implemented. In some utilities, the system-control department continues to do the unit-commitment (before-the-fact scheduling of generating units) and dispatch [real-time control of generation to manage area-control error (ACE)] for all of the utility's generating units. The marketing department, in such cases, is responsible for buying and selling energy and capacity for native load and wholesale transactions. The results of these trades are passed to the system-control department, which incorporates these activities into its unit-commitment and dispatch operations.

In other cases, the marketing department is responsible for scheduling the utility's generation resources to meet native load and to satisfy the utility's wholesale obligations. In such cases, the system-control department performs only the real-time dispatch of generators. In still other cases, the marketing department is responsible for both generation scheduling and dispatch; the system-control department calculates ACE and passes this error signal to the marketing department, which then decides how to share the ACE responsibility among its appropriately equipped generating units. The system-control department retains the North American Electric Reliability Council (NERC) control-area-operator responsibilities and therefore has the right to directly control generating units to maintain reliability.

This diversity in the treatment of system-control functions reflects the rapidly evolving nature of bulk-power operations and regulation. In part because of the concerns expressed by power marketers, transmission-dependent utilities, and industrial customers, FERC is promoting and utilities are forming new entities called independent system operators (ISOs) to perform these functions.

As the shift from individual utility control centers to regional ISOs occurs, the number and nature of the functions associated with system control will change and likely grow. Table 1 lists the responsibilities of the Southern Company Power Coordination Center. (With more than 30,000 MW of generation capacity, Southern is larger than some ISOs.) The center operates all the generation and transmission resources owned by the individual operating companies, including Georgia Power, Savannah Power and Light, Alabama Power, Mississippi Power, and Gulf Power.

Table 2 lists the functions of the California ISO. The ISO functions are much broader than those of today's typical control-area operator (compare Tables 1 and 2). As examples, the California ISO makes more explicit its functions in scheduling and coordinating the transactions and proposed

Exhibit 1. Elements of the system-control service as defined by the Interconnected Operations Services Working Group

The service is essential to
- # Preserve a real-time generation and demand balance within prescribed electrical boundaries and support Interconnection frequency through frequency control
- # Ensure transmission security of the bulk transmission systems within its electrical boundaries and its Interconnection
- # Maintain an appropriate level of emergency preparedness to respond to, and mitigate the effects of: generation and transmission contingencies, system disturbances and other emergencies
- # Enable commercial markets for electricity products

The provision of statistics regarding the production and consumption of electricity products supports the settlement and reconciliation processes.

Service providers must have adequate facilities, information, capabilities, authority and staff competencies. Facilities normally include a real-time Energy Management System or SCADA [Supervisory Control And Data Acquisition] system. Conventional tools and information will have to be enhanced to:
- # Track contracts (including re-selling and retitling) for electricity products and services
- # Process transmission service requests
- # Continually predict and calculate available transfer capability
- # Monitor and respond to inter-regional reliability concerns
- # Identify appropriate actions that are physically and contractually correct following contingencies or during periods of gradual system degradation

Physical capabilities include dispatch of generation resources (including AGC) and control or deployment of bulk transmission facilities (may include the switching and tagging of equipment).

power flows of various generating companies, scheduling coordinators, and others planning to use the California transmission network. The ISO functions need to be more explicit than those for today's utility control area operator because the ISO owns no generation or transmission resources. The extent to which the ISO can direct the operations of resources owned by other entities must be explicitly stated in contracts and tariffs. The typical vertically integrated utility, on the other hand, includes generation, system control, and transmission within the same corporate entity.

INCREASE IN BULK-POWER TRANSACTIONS

Utilities report substantial increases in the number of schedules and schedule changes and corresponding declines in the size of the average transaction. Formerly, these transactions were primarily with adjacent utilities. Now they are with a variety of entities, including neighboring and distant utilities, independent power producers, and power marketers.

For example, the number of transactions handled by Duke Power more than doubled between 1995 and 1996, increased another 50% between 1996 and 1997, and appears to be increasing by about 40% in 1998, as shown in Fig. 1 (Reinke 1998). In a similar fashion, the number of transactions handled by Southern Company Services increased from about 400 per day in 1995 to 585 in 1996, 735 in 1997, and 820 in the first half of 1998 (Vice 1998).

COSTS AND CUSTOMER CHARGES

Several utilities and three ISOs provided information on the annual capital and operating costs for system control and the customer charges for this service (Table 3). Most utilities charge wholesale customers for system control on the basis of reserved transmission capacity, expressed as $/kW-month.

Typically, the utilities based their FERC-filed tariffs on the costs booked to two FERC Form-1 accounts, both part of Electric Operation and Maintenance Expenses:

- # Account 556 – System Control and Load Dispatching (part of Power Production Expenses, E. Other Power Supply Expenses) and
- # Account 561 – Load Dispatching (part of Transmission Expenses).

Table 1. Functions of the Southern Company Power Coordination center

Unit commitment: determine the appropriate set of generating units and other power-supply resources required to economically meet projected integrated system demand on a daily basis.
Economic dispatch: determine the desired loading of the generating resources connected to the integrated system.
Common interchange: implement the interchange of power with the nonassociated companies that are interconnected with the Southern electric system.
Bulk-power transmission security: assess the security of the transmission system and concur on actions required to ensure its integrity under first-contingency conditions.
Maintenance-outage coordination: coordinate the unit maintenance requirements of the operating companies to minimize cost to the system.
Record keeping: maintain specified operating data and records.

Source: Georgia Public Service Commission (1998).

In addition to these operations and maintenance costs, the utilities typically include an annualized capital cost to reflect depreciation, taxes, and return on investment associated with the system-control facilities, such as buildings, backup power supply, communication equipment, and computer systems and programs. The mix of capital costs and operating expenses differs among utilities.

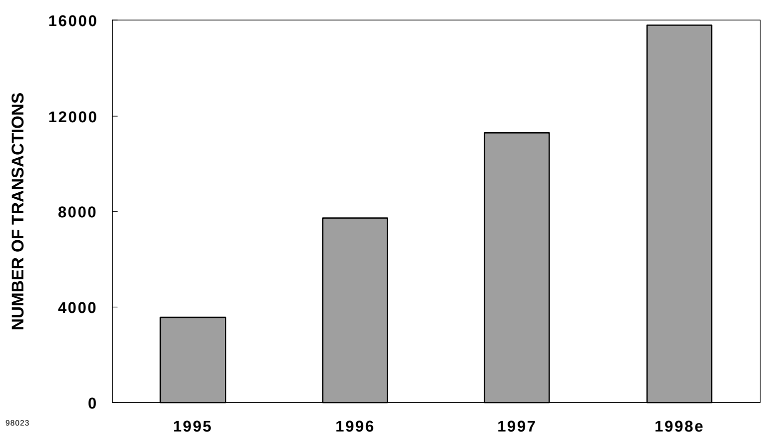

Fig. 1. The number of wholesale transactions handled by Duke Power in North and South Carolina. The 1998 estimate is based on data for the first quarter.

The average system-control charge for the nine utilities shown in Table 3 is $0.09/kW-month. The range of charges is $0.02 (which FERC staff proposed to more than double to $0.05) to $0.20/kW-month. An analysis of 12 utility tariffs in place as of 1995 (i.e., pre-Order No. 888) showed an average price for system control of $0.08/kW-month, very close to the more recent results shown in Table 3 (Kirby and Hirst 1996). The range across these 12 investor-owned utilities was $0.03 to $0.18/kW-month. The utility charges likely differ for two reasons. First, the utilities include somewhat different functions within this service. Second, the assignment of various costs to different accounts differs among utilities.

The California ISO charge is much higher than those for utilities. This difference is probably caused by the greater number of functions performed by the ISO (Table 2) and by its high startup costs. That is, functions that might show up in transmission charges for a utility are included in the California ISO charge. In addition, the California system is very complicated.

The Electric Reliability Council of Texas (ERCOT) ISO performs fewer functions than does the California ISO. Texas has no centralized power exchange and 10 utilities within ERCOT operate their own control centers. The ERCOT ISO implements the state's OASIS system, handles transmission reservations, and serves as the security coordinator for the region. The annual cost for the ERCOT ISO is $4.2 million (Jones 1998). About 75% of this total is operating expenses, with the remainder capital costs. The capital costs are low because ERCOT had two security centers before the state established the ISO. The ISO took over one of the existing facilities and uses the other one as its backup, thus reducing greatly its startup costs. ERCOT's costs are collected through membership fees, OASIS fees, fees paid by load-serving entities, and a $0.15/MWh charge on all unplanned (up to 30 days) uses of the transmission system. Normalizing the entire $4.2 million by the annual average of the 12 monthly peaks yields an implicit ERCOT ISO charge of $0.0088/kW-month. The ISO charges are in addition to the scheduling charges of the individual utilities.

The 1997 annual operating and capital costs for the Pennsylvania-New Jersey-Maryland Interconnection (PJM Interconnnection 1998) amounted to $30.4 million, equivalent to a charge of $0.066/kW-month. The PJM cost per kW-month is much higher than that for the ERCOT ISO because it includes more functions, including operation of a power exchange. The PJM cost is much less than that for California, probably because the PJM ISO is based on a pre-existing tight power pool.

Table 2. Functions of the California ISO

Scheduling
Provide operating information and system status day-ahead and hour-ahead for each zone and node
Determine whether proposed schedules can be met or will create congestion
Prepare suggested and adjusted schedules
Validate ancillary-service bids and self-provided ancillary services
Reduce congestion based on adjustment bids
Make mandatory adjustments to schedules, if necessary, to manage congestion
System operations
Establish ISO control center and backup facility
Direct the physical operations of the ISO transmission facilities
Commit and dispatch reliability must-run generating units
Order necessary changes in equipment to control voltage or frequency
Take necessary actions to protect against uncontrolled loss of load or generation and/or equipment damage
Control the outputs of generating units that provide ancillary services
Dispatch curtailable loads when needed
Procure supplemental energy
Coordinate and approve outages and returns to service for transmission and must-run units
Coordinate and approve maintenance outages for ISO transmission facilities
Forecast generation reserve needs
Facilitate market for additional generating capacity needed to meet reliability criteria
Ensure that sufficient ancillary services are available to maintain reliability; determine the amounts of each service required, purchase these services from individual suppliers, verify supplier performance, and subsequently pay for services delivered
Coordinate transmission-planning and expansion
Coordinate operations with each distribution company
Establish operating protocols for generating units connected to the ISO grid
Operate internet-based transmission information system and provide nondiscriminatory access
Establish and implement FERC-approved transmission tariff
Establish metering standards
Establish settlements and billing systems for all ISO transactions
Establish dispute-resolution procedures
Facilitate work of ISO Technical Advisory Committee

Source: California ISO (1997).

EMERGING ISSUES

Exactly what reliability and commercial functions define system control is a critical and, in many locations, unresolved issue. A narrow view of this service would encompass only the short-term (day ahead to real time) functions of transmission information and reservation, system security, and generation/load balancing. A more expansive view would encompass coordination of transmission (and perhaps generation) maintenance outages and transmission planning and expansion.

A second critical issue concerns who performs the functions assigned to system control. Vertically integrated utilities note the economies of scope and the low transaction costs from having the same entity perform both generation and transmission functions. Customers and power marketers, however, are concerned about market-power abuses. They prefer operational unbundling or corporate divestiture to FERC's requirements for functional unbundling of generation from transmission.

The ongoing debates about formation of ISOs is a reflection both of the diversity of views about functionality as well as about unbundling of generation from transmission. FERC's (1998a) inquiry on its ISO policies displayed the full spectrum of views. Its April 1998 technical conference included panels on the structure and role of ISOs; their regulation, governance, and independence; the role of states; reliability; transmission pricing; market monitoring; and FERC regulation. More recently, FERC (1998b) issued a notice concerning the creation of regional transmission organizations, pursuant to its authority under Section 202(a) of the Federal Power Act.

Over time, the functions included in system control may expand as the entities that perform these functions shift from individual utilities to regional ISOs. This shift may occur in part because of concerns about vertical market power and in part to improve efficiencies in system planning and operations. On the other hand, these functions may be dispersed among separate corporate entities, such as control-area operators, transmission operators, ISOs, Transcos, and regional security coordinators.

Table 3. Costs and charges for system control for a few utilities and ISOs

	Annual cost (million $)	Customer charge ($/kW-month)
Niagara Mohawk	2.26	0.02
Detroit Edison	0.511	~0.022
Montana Power	2.93	0.19
El Paso Electric	2.03	0.16
Oklahoma Gas & Electric	--	0.0812
Southern	29.67	0.0766
Virginia Power	1.65	0.0113
Ohio Edison	4.69	0.0754
Portland General Electric	3.42	0.20
California ISO	153	~0.37
ERCOT ISO	4.2	~0.0088
PJM Interconnection	30.4	~0.066

Some of the ISO issues related to system control that remain unresolved include:

- Structure and role: optimal size, responsibilities, and whether the ISO should be a control-area operator
- Governance: independent or stakeholder board of directors
- Reliability: relationship between ISO and regional reliability council; should ISO be security coordinator
- Regulation: should FERC require (not just encourage) ISO formation
- Evolution: is the ISO a transitional or end state; would Transcos be preferred
- Incentives: what incentives can and should be provided to ISOs to encourage them to appropriately balance reliability with maximum throughput
- Transmission planning and construction: what role should ISOs play.

A review of the recent proposals to create ISOs shows that system operators may be called on to perform a variety of functions ranging from real-time control to long-term planning. There is near-universal agreement that system control should include automatic protection and disturbance response. Considerable disagreement exists over the role of system operators in economic dispatch and unit commitment of generators. Some proposals call for the ISO to perform these functions (e.g., PJM); others call for a separate power exchange (e.g., California); and others prefer to leave these generator operation and scheduling issues entirely in the hands of generator owners (e.g., the Midwest ISO). While only control-area operators can generate the overall ACE signal, either the ISO or one or more generation entities could control the generating units that provide the regulation service. Most of the ISO proposals call for ISO participation in, coordination of, or leadership in scheduling maintenance of transmission facilities and in planning transmission expansion. The proponents of Transcos believe that such entities, which both own and operate transmission, can better plan for and construct transmission additions than can an ISO. In general, the ISO and Transco proposals envision no or very limited roles for the ISO in generation planning.

Key unresolved issues associated with system control include: What functions constitute system control? What can NERC, FERC, and the industry do to ensure that vital functions that fall outside FERC's current narrow definition of system control continue to be performed? How can the reliability and competitive-market functions of system control be reasonably split to promote competition and minimize the transaction and coordination costs associated with this vertical deintegration? What role will (should) ISOs have in providing system-control functions?

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