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Jack F. Morris
Missouri University of Science and Technology

Frank J. Kern
Missouri University of Science and Technology, fkern@mst.edu

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Distribution Automation for the Association of Missouri Electric Cooperatives—A Statewide Evaluation of Load Management

JACK F. MORRIS, FRANK J. KERN, AND EARL F. RICHARDS

Abstract—**Presented is an in-depth technical and economic feasibility study utilizing one- and two-way management systems for statewide load control and distribution automation. Included are 1) an evaluation of the generation and transmission load patterns of the state cooperatives and the determination of the amount of controllable load for use by a load management system, 2) an in-depth economic cost-benefit study as a result of implementing a load management system on a statewide basis, 3) communication alternatives for implementing the statewide load management and distribution automation system, 4) an investigation into using an existing statewide microwave communications system for direct load control, local control, or distribution automation, and 5) a cost-benefit study using new technologies such as fiberoptics, AM and FM broadcast, ripple, and carrier modulation for system control.**

I. Introduction

THIS study was conducted by the Department of Electrical Engineering, University of Missouri–Rolla for Associated Electric Cooperative, Inc. (AECI), Springfield, MO. An in-depth technical and economic feasibility study was performed for statewide load control and distribution automation and included the following items:

1) evaluation of the generation and transmission (G&T) cooperatives' present load patterns, an estimation of the amount of load that would be controllable by a load management system, and the economic benefit to be derived from the anticipated modification to existing load patterns upon implementation of a statewide direct load control system;
2) evaluation of communication system alternatives for power distribution system automation;
3) investigation of direct load control, distribution automation, and customer communication functions that could be implemented on a statewide basis using existing or proposed new communication technologies, and a determination of the economic costs and benefits of such implementations;
4) identification of the technologies required to achieve the desired end result without regard to existing equipment or systems;
5) identification or specification of a system implementation scheme that would allow partial installation of the system, as determined by each member cooperative's requirements, with subsequent compatible system upgrading to achieve the option end result.

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J. F. Morris and F. J. Kern are with the Department of Electrical Engineering, Room 107, University of Missouri–Rolla, Rolla, MO 65401.

E. F. Richards is with the Department of Electrical Engineering, Room 122, University of Missouri–Rolla, Rolla, MO 65401.

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Load control data, and information on communications and control system performance and capabilities, was gathered from a review of 30 of the more mature demand-side management (DSM) projects conducted by ten utilities. Equipment manufacturers were interviewed, several G&T and distribution cooperatives were consulted, and demonstration projects were visited.

A set of evaluation factors pertinent to DSM hardware systems was then defined, and each of the systems studied and evaluated according to those factors and the information collected through the literature review and conferences.

II. Load Control

Typically about 75 percent of annual residential energy use is for air conditioning, space heating and water heating. These loads have a large demand at the time of the system peak, and direct control applied to these customers has the greatest potential for meeting the objectives of load management by an electric utility.

Control technologies effectively inhibit operation of selected appliances for part or all of the control period in order to rearrange the daily load profile. The control may be executed through one of three types of load control:

direct control, where all control decisions are determined by the utility central control station and communicated to the control switch on the customer premises through a remote control system;

local control, where all of the control decisions are determined by local decision-logic devices located on the customer premises; and

distributed control, a combination of direct and local control.

A communications system is required for both direct and distributed control. Direct control is the most commonly used approach to end-use load control; in particular, air conditioners and water heaters together account for 77.5 percent of the load management activity in the U.S.

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III. Air-Conditioning Load Management

Residential air conditioning is a major contributor to system peak demands in summer peaking utilities, usually peaking within a few hours of the system peak demand. In cooperatives with only a small commercial air-conditioning load, the residential and system loads tend to peak at nearly the same time, with the time difference increasing as the commercial air-conditioning load increases.

Criteria for determining when to apply direct control vary widely. Some cooperatives use it 1) whenever an imminent need for it exists, 2) on a regular basis to accustom customers to its presence, and 3) as a last resort when all other control and operating options have been exhausted. Some utilities use load following control, varying the intensity of control or the number of customers controlled with the time of day or magnitude of the system load. This permits maximum control when needed, while avoiding unnecessary control at other times. Load profile data was obtained and changes due to load control measured, an average coincident load reduction at the time of system peak from 0.5 kW to 2.0 kW per household.

Fig. 1 shows percent load-change curves for cycling intensities (percent of time OFF during each half-hour) of 25, 35, and 50 percent, respectively. The figure shows that the load change increases with the cycling intensity, which is to be expected, and that the payback is, in general, less than the deferred energy consumption.

The connected air-conditioner loads reported in projects considered in this study varied widely, as shown by the following connected loads, which are averages for the utilities, not values for individual customers within the utility.

- Minimum connected load: 1.5 kW.
- Average connect load: 4.9 kW.
- Maximum connect load: 8.4 kW.

Load changes due to load control, measured as the coincident load reduction at the time of system peak, varied widely. The following are typical values for coincident peak reduction.

- Minimum: 0.50 kW.
- Average: 1.0 kW.
- Maximum: 2.00 kW.

This wide range of values is due to the differing values of connected load, cycling intensities used, and air-conditioner sizing practices. As illustrated by Fig. 2, the coincident load reduction is dependent not only on the load reductions occurring as a result of load control, but also on the relative timing of the system load. The coincident peak demand may not be a desirable measure of load-management characteristics.

Fig. 2 shows idealized system and diversified end-use load curves, both normalized to their individual peak values. The end-use load curve is shown both with and without load management. Reduction in demand is not constant throughout the day, having its greatest value when the end-use load curve peaks. The planner interested in reducing system peak demands is concerned with the value of the end-use load curve at the time of the system peak, termed the coincident demand.

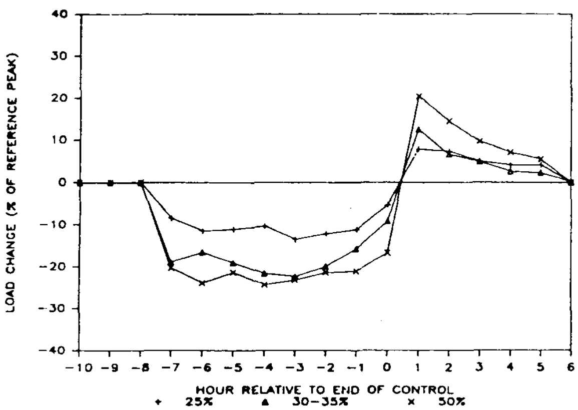

Fig. 1. Air-conditioning direct load control summary of project load profiles.

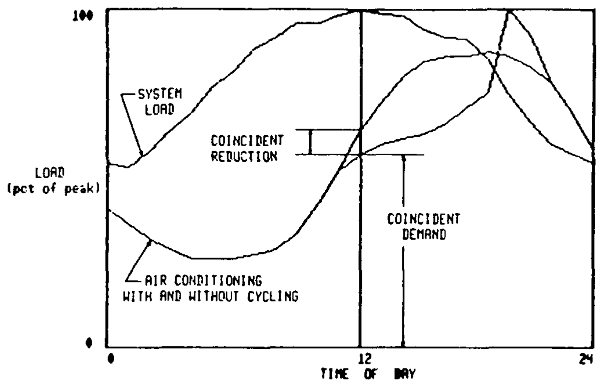

Fig. 2. Coincidence of system and air-conditioning load curves.

It is evident from the figure that the coincident reduction may be significantly less than the reduction of the end-use load at the time of its peak.

This illustrative example emphasizes the fact that load management must be performed to meet the planning and operating needs of the utility, not simply to reduce the peak demand of the load being controlled, because these two approaches are not equivalent.

The communication system linking the utility central control station with the customer is the key technological feature of air-conditioner cycling and the principal cost component of the control system.

Cost-comparative analysis was collected for VHF–FM radio and one-way power-line carrier communications, the two most widely used communication technologies in the United States for direct load control.

For each of these two technologies average capital costs for central station and receiver equipment were determined. Transmitter costs were included in the central station costs. Annual maintenance and operations costs were not included.

- Costs are approximately twice as high for a one-way power line carrier as for VHF–FM radio. Carrier transmitter costs are necessarily higher because of the need to inject a signal directly into the power line and because a large number of transmitters may be needed for adequate coverage over several distribution feeders.

- The power line carrier is not attractive for small test and demonstration programs where the central station costs must be borne by a small number of points of control. This explains one of the reasons why FM radio has been so widely used.
- As the number of receivers approaches about 5000–6000 units, the total cost per point is dominated by the receiver costs, with the central station costs being only a small component. Thus, while central station costs are the dominant cost elements for small-scale projects, this is not the case for large-scale implementation projects.

IV. Water-Heater Load Management

Direct control of water heaters is done using a scheduling strategy: water heaters are turned off for periods of from two to six hours during the peak period. Staggered control strategies are necessary when the duration of the peak period is longer than the duration of control acceptable to customers. The technologies and costs are not significantly different than for air conditioners. The operating procedures, however, are very different. Many utilities use the same communication system and receiver to control both central air conditioners and water heaters, and a few also control space heaters.

Average load profiles for control periods of 2-, 3-, 4-, and 6-hour control durations are shown in Fig. 3. As for air conditioners, the magnitude of the load change due to control (in kilowatts) depends upon the magnitudes of the uncontrolled load profiles, which show a great difference between summer and winter. The percent changes, however, were not detectable.

Water-heater load profiles with direct load control show a large payback effect as electricity use, deferred during the peak period, is used after the peak period ends. This payback demand, which is often larger than the diversified uncontrolled peak load, can cause severe problems if it is not recognized when developing control strategies. When recognized, however, it is readily handled by staggering the times at which the water heaters are restored to service.

Diversified residential water-heater loads generally have two daily load peaks, with one in the morning and one in the evening. During the winter, these peaks tend to coincide approximately with the two system peaks occurring at this time, which are caused in large part by electrical water and space heating. Fig. 4 shows several water-heater load profiles obtained from different utilities.

The low natural duty cycles of water heaters makes it impractical to perform the same kind of cycling as is done for air conditioners.

- The 30-min cycling of residential water heaters does not result in significant reduction in diversified water-heater demand. This is due to the high natural diversity of uncontrolled heaters.
- Cycling has little effect on reducing water-heater diversified demand. Tests with OFF cycling strategies under 80 percent have no impact, since the duty cycle of water heaters reaches a maximum of only 22 percent during extreme weather periods. OFF cycling strategies of over 80 percent are not practical, since the ratio control switches had a 20-percent tolerance.

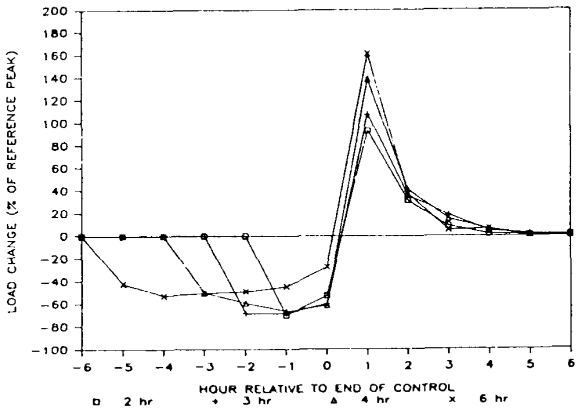

Fig. 3. Water heater direct load control summary of project load profiles.

Water heaters are usually controlled by scheduling them to be inhibited from operation, or OFF, for extended periods during the control period. The OFF period is limited because of the limited amount of storage capability of the standard water tank. The projects included in this study had utility average OFF times ranging from 2.4 to 4.2 hours, with an overall average of 3.9 hours. This control duration has been found by utilities to result in levels of inconvenience and discomfort that are not acceptable to customers, as measured by complaint calls. The desired period of control, however, may be much longer, beginning with the morning peak and concluding with the end of the evening peak. The control durations above may not be adequate to provide utilities with the load relief they need during the peak period. When the practical OFF time is not sufficiently long to meet utility needs, the utility can stagger the OFF times. This makes a longer duration of control possible for the utility, but because not all of the water heaters are inhibited or OFF at the same time, the average diversified load reduction, as viewed by the utility, is less. The composite effect of such staggered control strategies is determined from a knowledge of the effect of each control group individually.

Utilities can also extend the control period by taking advantage of the load valley between the morning and evening system peaks to permit partial reheating of the water heaters during this period.

V. Space-Heating Load Management

Typical electric space-heating loads are shown in Fig. 5. There are two residential space-heating peaks, one occurring in the early morning and the other in the early evening. The characteristics of the curves in the figure must be noted when evaluating load-management technologies and operating strategies.

Duty-cycle load-limiting strategies have been investigated by several winter peaking utilities because they are relatively inexpensive strategies to implement, as compared with thermal energy storage and some of the other "high-tech" solutions to space-heating load management that have been proposed. Implementation of a cycling strategy requires only

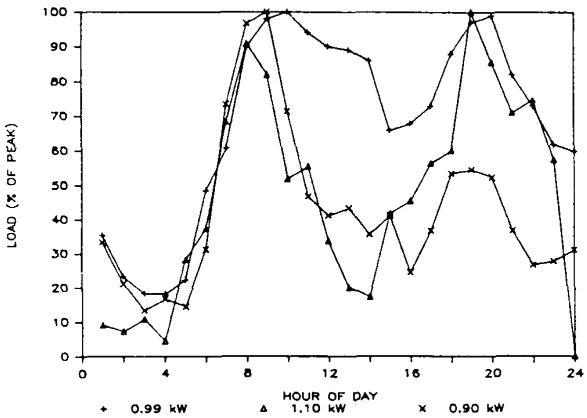

Fig. 4. Uncontrolled water heater load characteristics.

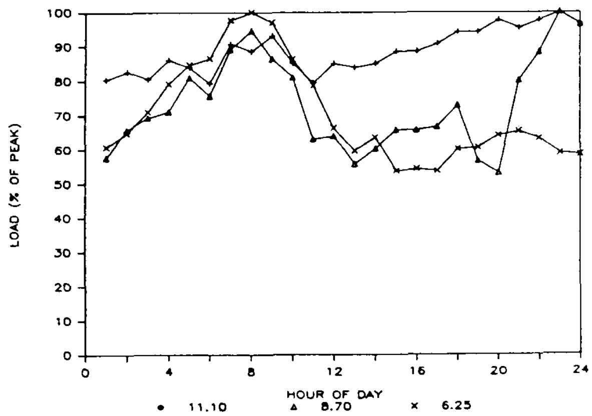

Fig. 5. Space heater load profiles without load management.

the addition of simple controls to the existing heating system. These strategies have not proven as satisfactory for space heating, however, as they have for air-conditioning and water-heater control.

- Space heaters usually operate with a low natural duty cycle, often only about 30 percent.
- Air-conditioning cycling typically operates when there is a temperature difference between the inside and outside of a home of approximately 20 degrees. Space heating, on the other hand, may involve much greater differentials, sometimes as large as 100 degrees. As a result, heat loss from a home during the winter is much more rapid than heat gain during the summer. Thus the adverse impact of cycling on customers would be much more noticeable during the winter than during summer. Typically a 65–75 percent cycling strategy is required to gain any reduction of space-heating load. During a three-hour cycling control period, a five-degree drop in interior temperatures was typically experienced.

VI. Communications and Control Systems for Load Management

Power Line Carrier

Typical power-line carrier (PLC) operating frequencies are in the 5–15 kHz range. These higher frequencies offer several advantages. Normal power-line noises (due to harmonics and other electrical disturbances) drop off rapidly at frequencies above 3–4 kHz. This noise reduction allows a PLC system to use less signal power to achieve an acceptable signal-to-noise ratio for reliable signal transmission and the reception that would be needed by a ripple system. The high-frequency operation of a PLC system also allows a more rapid signaling scenario because more information per unit can be transmitted as the frequency increases. Modern power-line carrier equipment designed as high-impedance (relative to the network) carrier sources and loads result in current-source transmitters and voltage-source receivers capable of providing extremely reliable communication over the power-distribution network.

Power-Frequency Communications Systems

In the power-line carrier system, unlike all other power-line communication systems, the patented technology of two-way automatic communications system (TWACS) does not impose either a high- or low-frequency carrier on the power network. Rather, the system operates within the range of the power frequency to provide two-way communication over the utilities' own power network. Since the power network is designed for minimum loss at 60 Hz, the elimination of a higher frequency carrier assures excellent signal propagation. More importantly, the signals can be imposed and extracted without the need for high signal power or network modification (repeaters, bypasses).

Two-Way Radio Systems

Although there are a number of two-way demand-side management communications and control systems available, only a few use radio signals for both the outbound and the inbound signal.

Thirty-four radiofrequency (RF) pairs, in 25-kHz increments, have been allocated for use in point-to-multipoint service for data acquisition and control telemetry.

AM Broadcast Radio Two-Way Systems

AM broadcast radio offers another alternative. It can be shown that the residual RF carrier power that remains in the AM process contains 67 percent of the available radiated power and is essentially unused. The usable audio sideband signal power is, at most, 33 percent of the total power, and this is what conveys the voice and music; the audio sideband averages only about 10 percent of the total radiated power.

If a load-management subcarrier control tone is injected on an AM broadcast station using conventional amplitude modulation, interference (cross-talk) can develop between the control tone and the regular audio program of the station. Furthermore, if this AM tone is "subaudible" then it will have difficulty passing through the radio station's modulation transformer.

The main features of AM broadcast are that

- the effective radiated audio power of the broadcast station is unaffected,
- no cross-talk exists between synchronous quadrature modulation (SQM) control signals and the regular audio program,
- the system has much greater immunity to RF noise and

static due to weather (profits by FM signal capture),

- the SQM data rate is 5–10 times faster than the AM subcarrier tone approach,
- Altran's digital synchronization method is simple and reliably derived from the broadcast RF carrier, and
- an AM station carrier can synchronize forward and return link devices because it is on continuously.

The complete two-way communication system features a return communication link in either the VHF or UHF bands, using the broadcast station signal as a frequency reference for the transmitter and as a coherent source for a synchronous detector in the receiver.

Ripple Control System

A ripple control system utilizes a utility's transmission or distribution system as the medium for transmitting signals.

A typical ripple control system can be used to control loads such as water heaters, air conditioners, space-heating circuits, and irrigation pumps. It can perform automated distribution functions, such as capacitor switching or line switching, and can be used in conjunction with on-site local logic controllers or energy storage systems.

UHF Radio Control Systems

Radio has gained wide acceptance because of its relatively low cost, simplicity, and proven reliability. Its main disadvantage is that terrain features and large buildings can reduce signal propogation to an effective range of 5–25 miles for a 300-W transmitter. The 300-W power limitation, imposed by the Federal Communications Commission, can be circumvented by adding remote transmitters with an overlapping signal pattern, but at a higher cost. Older radio systems also can suffer from problems with signal overlap from adjacent utilities involved in load control, or from the various emergency and commercial users that use a similar frequency.

VII. The Associated Electric Cooperative, Inc. (AECI)

The AECI system serves approximately 400 000 customers, most of whom reside in rural Missouri. Winter and summer peak loads are generally in the region of 1500–2000 MW. The winter peak-day load factor is typically about 90 percent, while the summer peak-day load factor rarely rises above 80 percent.

AECI is divided into six generation and transmission cooperatives (G&Ts) which are further subdivided into some 40 smaller distribution cooperatives. The rates charged to the distribution cooperatives are composed of two components: a maximum demand charge and an energy consumption charge. Although one distribution cooperative may achieve a reduction in its own maximum demand payment by successfully applying load management to its own distribution system, this may not necessarily benefit AECI since all cooperatives do not have peaks coincident with AECI. Furthermore, other cooperatives with less effective load management, or none at all, would need to make good the financial deficit created by this single enterprising cooperative. This problem prompted AECI's recent interest in investigating how a system-wide load-management scheme could benefit all parties involved. This interest has been responsible for initializing this study.

VIII. The Loadsim Program

LOADSIM is a digital computer program available from the Electric Power Research Institute that forecasts the system loadshape impacts of load management. These modified loadshapes can then form the basis for a detailed assessment of the cost-effectiveness of different load-management strategies and technologies as determined by their effects on electric utility and customer costs.

LOADSIM consists of two subprograms. The first of these, called PROFILE, is a simulation model of the transient heat transfer and gain of a residential dwelling, and is designed primarily to permit the user to assess the effects of HVAC appliance control on dwelling temperature and HVAC electrical load. PROFILE represents a dwelling/appliance system modularly.

One of PROFILE's modules, the control module, oversees the operation of the appliance being controlled.

In addition to ambient weather data, a necessary input in any load-management investigation is the type of control strategy to be investigated. PROFILE accommodates the following modes:

1) no control,
2) utility cyclic control,
3) adaptive thermostat setting,
4) customer shutdown, and
5) weekday but no weekend control.

As its primary outputs, PROFILE returns the following:

1) HVAC electric load with or without load management,
2) indoor house temperature, and
3) indoor house humidity.

Although PROFILE can be used to model an individual house where the electrical load curve is typically a series of step functions, it also includes a facility whereby the "average" house is modeled. This makes it possible to investigate the effects of load management on the total system. This is more useful to the system's engineer than curves for one particular house.

The second LOADSIM program, called LDSHPE, translates the information obtained from several PROFILE runs into the diversified appliance load. One may perform up to four PROFILE runs for one house, to determine each of the following load curves:

1) appliance load for house without load management, with appliance on all day;
2) appliance load for house without load management with appliance off for part of the day;
3) appliance load for house with load management, with appliance on all day;
4) appliance load for house with load management, with appliance off for part of the day.

These four PROFILE runs form the basis upon which the modified system load can be determined. LDSHPE basically subtracts the uncontrolled load (the appliance load identified for the case of no load management) from the system load, and then adds in the controlled load (the appliance load identified

for the load-management case). LDSHPE therefore needs to be supplied with the original system load data and the number of homes that the modeled house is intended to represent as well as some secondary data concerning customer behavior. The latter might include a nominal time in the morning when the customer leaves, and a corresponding returning time in the afternoon, as well as estimates of the number of people who leave and return a fixed number of hours before and after these nominal hours, and an estimate of the number of people who stay at home all day.

A LDSHPE run can be followed directly by more runs intended to investigate the effects of a different control strategy on other types of homes. In this case the modified system load curve is fed to the next state of execution as the "original" system curve.

IX. General Structure of a Statewide System

A statewide system to deliver direct load control and other customer-related functions to the consumer level must be viewed as an integrated system that performs other functions as well. In particular, such a system must include some means for coordinated generation control, economic dispatch, and bulk power purchase at the system (statewide) level. It must also, at the individual G&T level, include provision for normal control, SCADA, and data-collection functions (for billing purposes, for example). In addition, the system must be capable of performing many functions related to distribution automation as well as customer-related functions. What all of these functions are and how they might be implemented with currently available technology will be discussed in the following sections. This section will discuss two possible overall structures for such a system.

Centralized Control Structure

At the top level, an energy-management system performs economic dispatch calculations and schedules generation as well as providing pricing and coordination information to the separate G&T companies. Data collection relating to overall system operation would be collected and achieved at this level. These functions are currently implemented by most utilities at the first level of the control hierarchy. In addition to these tasks, the software for scheduling direct load control could reside at this level. When load control is to be invoked, control commands would pass down the communications path, through the G&T level, through the substation level, to the customer level. In a two-way system, return signals from the distribution substations would pass back up the communications chain to indicate the amount of load actually shed by each series of commands.

The second level of control functions would be allocated to the G&T level. Normal control and SCADA functions for the individual G&T are performed at this level. With a complete two-way system installed, SCADA information from every substation down to the distribution level would be available and could be incorporated into the SCADA system. In addition, all of the software used to control distribution automation load control and other customer functions would reside on a computer at the G&T level. This computer would operate in a multitasking environment, running control programs so that each individual distribution cooperative would be connected to this machine on a shared-time basis using a control terminal placed in the cooperative's office. The connection would be made through a serial communications port dedicated to each particular user so that, in effect, each user runs his own control program using a portion of the large machine. For functions requiring two-way data flow (for example, remote meter reading), the individual user would issue a series of control commands from his terminal that would cause the control computer to issue the appropriate commands to initiate the meter-reading sequence. The resulting meter data would flow from the customer level up through the communication chain to the G&T level, where it would be placed in temporary storage for retransmission to the individual user's database. The user would then issue the command for this data to be downloaded to his database at his convenience.

At the distribution substation two microcomputer-based controllers would be required. One would do 1) all of the control and monitoring of data within the substation, and would function as part of the SCADA system at the distribution level, and 2) act as the communications controller for the substation and be tied through a serial port to a second controller that would service the distribution automation and customer-service requests. The distribution controller would handle communications to the distribution level, would be able to run programs to sequence events (e.g., reading multiple groups of meters), and would have enough data storage to temporarily hold data arriving on the return path. This controller would also manage the reading of metering points, capacitor switching, and control of other automated equipment on the distribution primary level.

The control hierarchy described in the preceding is very similar to the type of system that might be used by a single very large utility, in that control and communications are handled at the "division" level by (possibly) a single large computer or computer cluster. It is therefore very vulnerable to failure of a single computer and should have the G&T level computer backed up by another system with automatic fail over capability. On the other hand, having all of the "computing power" in one location will simplify the problem of service on site. Also, some cost savings might (but not necessarily) be obtained by assigning each user at the distribution level only the computing resources required for the job at hand, making temporary expansion of these resources a relatively easy task. Finally, having the software for all distribution cooperatives reside in one location assures compatibility of all software and communications protocols, since it is assumed that one operating system will manage access to the machine.

Distributed Control Structure

Another possible statewide system can be structured by moving the distribution automation and customer-level services computing to the individual cooperative level. In this system, the economic dispatch and energy-management functions would be performed in the same manner as in the

previous section. In addition, a master control schedule would be used as part of the energy-management function to determine when it would be desirable to shed load and issue advisory messages (though not control signals) to the individual G&T communication links to be passed through to the individual distribution cooperatives' displays. The controllers for implementing the load control, as well as distribution automation and customer-service functions, would be located at the individual cooperative offices. Thus all functions at the distribution primary level and below will be initiated from that point. The system operations and SCADA functions at the transmission level down to the individual substations would be directed from control computers located at the individual G&T level in the traditional manner. The system integration function would reside in the communications network structure. Because the overall system structure contains a number of stand-alone systems, special care must be taken to ensure that data flow between systems is well coordinated so that conflicting requests for using the data network do not arise.

The advantage of this type of system structure is that having computer resources distributed at the lower level in the control hierarchy decreases the probability that computer failure will be a serious problem at the system level. It also structures the control hierarchy along traditional management boundaries. On the other hand, increasing the total number of control computers increases the likelihood that at least part of the system might fail at any particular time, since the total number of components in the system is increased and it is assumed that none of the computers at the distribution level would be backed up by duplicate equipment. Also, having computing equipment spread over a wide geographic area could slow down maintenance response time to computer failures because of the travel involved.

In summary, two major elements are required for a statewide system: first, a communication network to provide data flow between all points in the system in a coordinated manner at a sufficiently high data rate; second, a hardware system that consists of a master controller (or controllers), intelligent controllers at the substation level capable of executing programs on a stand-alone basis, and intelligent hardware at the distribution level capable of receiving and executing the commands sent to it as well as replying with data upon request. An inherent feature of such a system is that each component must reply to requests originating from the level above it in the control hierarchy rather than the other way around. This structure then precludes customer-initiated requests except on a polling basis.

X. Load Control and Distribution Automation Functions

It is technically feasible to implement certain functions using currently available technology or extensions of that technology which will become commercially available in the near future. This section will list those functions, grouping them at the consumer level, the distribution feeder level, and the distribution substation level.

Customer-Level Functions

Load Management—The first two functions listed below can be implemented with one-way communications systems. All others listed require a two-way communications channel.

Load Control—This controls individual customer loads on a scheduled or emergency basis and is used to change the shape of the load curve.

Pass-Through Commands—a) Load scheduling: allows for the control of customer loads, either on a prearranged schedule or on a demand basis. It will also respond to a system "scram" signal. b) Time-of-use signal: this will indicate to the customer via time-of-use metering what peak, shoulder, or off-peak rates are in effect. This may also change meter program internally.

Remote-Service Connect/Disconnect—Remote control is used to connect and disconnect customer service. Remote connect service can be provided with an "arm" button so that customer can initiate service connection after a connect authorization is sent. A status signal will be returned.

Remote Meter-Reading—An individual customer meter can be read and the reading returned to a central database.

Load Survey—This can be used to determine integrated demand. Intervals at which readings are taken are remotely programmable and data will be stored in meter memory and retrieved on demand.

Peak-Demand Metering—Allows changing of off-peak, shoulder, and peak revenue times and for setting of the meter register clock. Demand limits could also be programmed with alarms to the customer.

Tamper Detection—This provides count or status when service is interrupted or the meter is removed from its socket.

Distribution Primary-Level Functions on Feeder or in Substation

Data Monitoring—This will maintain a logical database to meet all user needs for logging, alarming, and user interface. It will compute data values not accounted for by other functions and will access metering points at both substation and distribution primary levels.

Data Logging—This provides a hard copy of distribution system operations and an event recorder to the distribution cooperative terminal, including

a) alarms and alarm summaries,
b) periodic logs of normal operating parameters,
c) demand logs and operator actions,
d) one-line diagrams of substation and feeder configurations and statuses, and
e) fault reports and event logs.

Analog Data "Freeze"—This provides a "snapshot" of all analog data associated with a substation or feeder during normal operation or prior to the occurrence of a system disturbance.

Cold-Load Pickup—This restores service to a distribution feeder, or feeders, after a prolonged outage, without causing protective relays to operate due to high inrush currents. This could include

a) control of user loads,

b) sequential restoration via use of remotely controlled feeder switches, and
c) adaptive change of overcurrent settings or characteristics of protective relays.

Integrated Volt/VAR Control—This is used to reduce distribution primary feeder losses and integrate system operation. It may be either automatic or manually controlled by the operator and permits the maximization of revenues off-peak and the reduction of load on-peak by voltage control. It includes

a) maintaining the substation bus voltage within limits by automatic tap changing,
b) maintaining feeder remote point voltages by controlling capacitor banks and feeder voltage regulators, as coordinated with the substation system,
c) maintaining the substation and feeder reactive power flow within limits, and
d) using measurements of individual feeder currents to provide calculated values instead of measured values for remote feeder points.

Automatic Substation Protection Functions

a) *Automatic reclosing*: Initiates or inhibits closing of a breaker in a programmed manner (breaker could be remotely programmed by operator).
b) *Bus fault protection*: Provides substation bus protection against all internal phase and ground faults.
c) *Instantaneous overcurrent*: Provides high-speed detection of feeder faults and an adjustable time-delay trip for fuse coordination or cold-load pickup.
d) *Time overcurrent protection*: Includes five remotely selectable time-current characteristics for improved coordination on the feeders.
e) *Adaptive substation transformer protection*: Changes protection to prevent tripping due to inrush, or changes protection limits with tap changes.
f) *Underfrequency protection*: Shedding load as frequency decreases (could also be a pass-through function).

SCADA Interface—The distribution automation system could be interfaced to existing SCADA by using a communications link and a special SCADA interface software package.

Automatic Bus Sectionalizing and Fault Isolation—Computer control is applied to substation equipment to detect overloads, operate protective equipment, reconfigure the substation bus, and restore service.

Feeder Deployment Switching and Automatic Sectionalizing—This would provide automatic or semi-automatic fault location, fault isolation, feeder reconfiguration, and service restoration. Automatic mode restoration, if possible, would be within one or two minutes after lockout. In the semi-automatic mode, operator concurrence would be required.

While all the functions described are possible to implement with existing technology, no commercial package is available that will single-handedly upgrade an existing system to perform all of these functions. Several different implementations are possible in terms of hardware.

The next section presents possible communications options that could be selected to support the operation of a system which would perform all of the functions listed in the preceding.

XI. Communication Requirements and Options for Statewide System

Available Media

The media available for point-to-point or point-to-multipoint communications are

- AM broadcast;
- FM broadcast;
- VHF radio, 150–170 MHz;
- VHF radio, 450 MHz;
- UHF radio point-to-multipoint, 928–958 MHz;
- UHF radio (''microwave'') point-to-point, 960 MHz;
- microwave point-to-point at 2 GHz, 6 GHz, and 12 GHz, as well as Ku band;
- fiberoptic cable;
- wide-band (TV) wire cable;
- satellite point-to-point and point to multipoint;
- leased telephone (T1 service);
- ripple;
- power-line carrier (T1 service).

Requirements

First, the medium that provides communications between Associated Electric, the various G&Ts, the distribution cooperative offices and substations, down to the distribution level must transmit digital data at a rate sufficiently fast to provide acceptable data rates for SCADA operation down to the distribution level, as well as communications for distribution automation. This is inherently a two-way path. Second, the data path from the distribution substation to the feeders and customers must be considered. The outbound path can use a transmission medium other than the data path into the substation. The return (inbound) path may or may not be a simple reverse of the outbound path, depending on the technology employed to implement the distribution automation and customer-service functions. This path operates at a much lower data rate simply because the currently available technology is designed to operate at a low data rate.

Possible Ways to Implement the High-Data-Rate Path
Unsuitable Candidates

The following media are considered to be unsuitable for the high-data-rate path because of the inherently low data rate of available systems:

- ripple
- power line carrier.

One convenient way to compare capabilities of communication media is in terms of equivalent voice frequency (VF)

channels. A single 25-KHz bandwidth VF radio channel can operate reliably, using no special encoding techniques at 2400 baud (baud/s). A standard dial-up telephone line can be operated at 100–1200 baud, depending on the quality of the line. Thus, as a rule of thumb, one VF channel can transfer approximately 300 characters (or symbols, or bytes, or 8-bit groups) per second. The maximum rate that can be expected from ripple and the power-line carrier is about equivalent to one dial-up telephone line. This is not to say that these technologies are not useful in some context but simply that, given the data requirements, better methods are available.

The following are considered to be unsuitable for reasons stated in the proceeding paragraphs:

- AM broadcast,
- FM broadcast,
- VHF radio at 150–170 MHz and 450 MHz.

Both AM broadcast phase modulation and FM–SCA (storecast) channels are available to provide wide area coverage at low cost. The available systems provide one-way communication at low data rates of less than 100 baud. Both must utilize some alternate return path and are thus not well suited for two-way high-data-rate service. VHF radio at 150–170 MHz is most widely used in one-way load-control scenarios.

VHF–FM radio progressed from very limited single-tone coding to dual-tone sequential, to digital encoding between the mid-1960's and late 1970's. As more utilities began utilizing the technology, more codes for more functions and abutting utilities become the expectation. Tone-coded receivers are still being manufactured for existing systems, but new VHF–FM systems are invariably digitally coded.

Merely different command codes have not solved all VHF–FM problems. There are 13 VHF frequencies potentially available to utilities for load management. Most are shared-use and have antenna height and effective radiated power (ERP) limitations. Only one of these frequencies, 154.46375 MHz, permits 300-W effective radiated power without shared-use problems.

Unfortunately the popularity of VHF–FM creates capture effect problems among abutting utilities. Capture effect causes the receiver to be captured by the strongest signal without respect to command codes.

XII. Conclusion

The study concludes that 150 MW of controllable load is available on a cycling basis with 600 MW available on a scram basis. To obtain this capacity, 275 000 points must be controlled. To control this load, the most economical one-way system to implement would use AM broadcast radio and one central control computer. The yearly cost of this system is estimated to be between $6 715 120 and $8 560 360, or between $2.03 and $2.59 per controlled point per month. Attempts to estimate benefits accruing from having this system in operation immediately yield estimates of from $0.00 to $8.59 per controlled point per month, depending on various conditions which are detailed in the study.

Installation of 40 individual load-control systems by 40 individual member cooperatives would cost approximately $0.50 per controlled point per month more than control of the same load on a centralized basis and would likely result in no greater benefit. The wide variance in potential benefits stems not only from lack of information, but also from uncertainty as to how benefits are to be distributed among those purchasing power from AECI.

There is also a high probability that a piecemeal implementation of load management will result in higher equipment cost to the cooperatives installing the equipment and a resulting cost increase for those cooperatives who do not. An in-depth investigation of the effect on member rates is recommended.

The two-way system will require two-way communications links to be established at least between the distribution cooperatives and their customers. When these links are established, remote meter-reading of kWh, peak demand, load survey, time-of-use metering, remote connect/disconnect, cold-load pickup, remote switching of capacitor banks, remote control of regulators, metering of analog data, and status monitoring can be implemented on the distribution system.

The communications media considered in this study were communications satellite 2-, 6-, and 12-GHz microwave, VHF radio, UHF radio cable TV, fiberoptics, and distribution line carrier. Not all of these options are appropriate for communications to the customer level. The results of this study indicate that distribution line carrier and cable-TV links are feasible as communication links from the distribution substation to the customer.

The term distribution line carrier (DLC) is emerging as a reference to a class of communications systems that use the distribution primary and secondary as the communications medium. The term refers to some systems commonly referred to as power line carrier (PLC) systems plus some emerging technologies that do not fit the common stereotype associated with that term. Two types exist: low frequency, relying on modulation of the 60-Hz waveshape, and high-frequency injection onto the 60-Hz signal. Field testing of first-generation power-line carrier systems indicated that these systems were much too sensitive to changes of configuration of the distribution system, that they required extensive tuning and line conditioning, and that they were susceptible to noise and harmonics on the power line. The DLC systems now entering the market reflect extensive modifications or complete redesign dictated by earlier field tests. In recent field trials, both low-frequency and high-frequency types show 95-percent or greater success in two-way communications on the first try, with 100-percent success attainable by successive retrials. These systems use sophisticated encoding and detection techniques not employed in earlier systems.

Cable TV with two-way capability is also reliable but very costly. Costs of installed cable are about $6000/mile, or a total cable cost of $582 000 000 to install 97 000 miles of cable to serve 400 000 customers. This study estimates that a per-customer/user monthly charge of at least $70 would be required. If the cooperatives want to supply receive-only television to their customers at a monthly charge of $39.95, this study indicates that such a venture is feasible.

For the two-way link down to the distribution substation,

extension of the existing microwave using UHF point-to-multipoint radio is the best current choice.

Where new installations are being considered for future high-density long-haul communications applications, fiber optic systems installed in the overhead neutral of transmission lines will be lower in cost and higher in capacity than microwave systems.

The study shows the most economical two-way system to install using currently available technology would be the use of a microwave/UHF link and distribution line carrier for the two-way link. The yearly cost to implement a minimum two-way system for 400 000 points to do load control and kWh and kW demand meter-reading only will be at least $36 068 000, or $7.30 per customer per month. The yearly cost for implementing a system to perform all two-way functions will be at least $85 582 960 or $18.66 per customer per month. The benefit of the additional functions is calculated to be $1.55 per customer per month for kWh/kW meter-reading only, and $4.03 per customer per month for the full featured system. These benefits do not include the benefits (unknown) of load control.

In conclusion, the study finds that implementation of any system will be less costly if done on a statewide basis, but will require the cooperative agreement of all involved.

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Jack F. Morris received the B.S. degree in electrical engineering from the University of Wichita, Wichita, KS, in 1962 and the M.S.E.E. degree from the University of Missouri–Rolla in 1965.

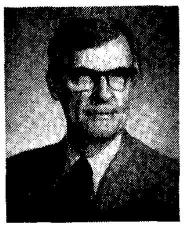
He is an Associate Professor in the Department of Electrical Engineering at the University of Missouri–Rolla and a member of the faculty of the University of Missouri–Rolla Power Engineering Program. He regularly teaches and does his research in the areas of electronics, power electronics, and power system analysis. He also has ten years of industrial and consulting experience in these areas. His current area of research is in the area of power system demand side management.

Professor Morris is a member of the IEEE Power Engineering Society and is active on the Demand Side Management Subcommittee.

Frank J. Kern received the B.S.E.E. and M.S.E.E. degrees from the University of Oklahoma, Norman, OK, in 1958 and 1963, respectively. He received the Ph.D.E.E. degree at the University of Oklahoma in 1966.

He is a Professor in the Department of Electrical Engineering at the University of Missouri–Rolla, where he is currently Undergraduate Program Coordinator. His area of interest is in automatic control systems, signal processing, and system modeling.

Dr. Kern is a member of Sigma Xi, Tau Beta Pi, and Eta Kappa Nu.



Earl F. Richards received the B.S. degree from Wayne State University, Detroit, MI, and the M.S. and Ph.D. degrees from the University of Missouri–Rolla (formerly the Missouri School of Mines and Metallurgy). All the degrees are in electrical engineering.

He has nearly 30 years experience teaching electrical engineering at the University of Detroit and the University of Missouri–Rolla. He has ten years of industrial and consulting experience. His general background is in modern control theory and signal processing. For the last ten years he has applied this theory to power system analysis, including system stability, economic dispatch, system protection, and computer methods in power systems. He has published many papers in the area of power systems and control theory.