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ABSTRACT - The Athens Automation and Control Experiment (AACE), a large-scale distribution automation research project, was conducted at Athens, Tennessee. The experiment involved the monitoring and control of three substations and twelve feeders (nearly the entire system) of the Athens Utilities Board (AUB). The monitoring and control hardware consists of supervisory and data acquisiton, feeder monitoring and control, and customer load control. In total 75 locations on the AUB distribution system were automated and 2000 customer loads were placed under control. The controlled equipment includes 2 load-tap-changing transformers, 12 circuit breakers, 4 line regulators, 29 capacitor banks, 35 load break switches, 12 power reclosers, and 21 fault detectors. Two software programs, an automated capacitor control program and a distribution automation analysis program, that have been essential to the AACE are discussed. There have been several operational benefits associated with the automation of the AUB system which are described in this paper.

INTRODUCTION

A large scale distribution automation research and development project has been conducted at the Athens Utilities Board (AUB) in Athens, Tennessee [1,2]. The project goal was to experiment with the integrated monitoring and control of an entire distribution system from a central distribution control center. The project was sponsored by the Department of Energy, Office of Energy Storage and Distribution, Electric Energy Systems Program and managed by the Oak Ridge National Laboratory.

AUB is a municipal electric system with 81 employees serving the city of Athens, Tennessee and the surrounding McMinn County. Over 10,000 customers are served in a 102 square mile area. The system peak load of 91 MW is served by three substations (North Athens, South Athens and Englewood) and twelve feeders with 440 miles of overhead line. The 8,906 residential customers have an average monthly consumption of 1,135 kWh. AUB is one of the 160 distribution systems which is supplied bulk power by the Tennessee Valley Authority (TVA). The North Athens Substation receives power at 161 kV from TVA and supplies power to six feeders at 13.2 kV and power to the Englewood and South Athens Substations through a 69-kV subtransmission line. Both the Englewood and South Athens Substations supply three feeders each at 13.2 kV.

For the experimental project, an automation system was installed to remotely monitor and control nearly the entire distribution system. The automated electrical system includes monitoring of 3 substations and 12 feeders, and monitoring and control of 2 substation load-tap-changing transformers, 12 feeder circuit breakers, 29 switchable capacitor banks, 35 load break switches, 12 power reclosers, 6 line regulators, 21 fault detectors, 200 remote revenue meters, and 2000 load control switches.

The automation system consists of a central dispatch room with two color CRT consoles and two report loggers. Communications to the substations is provided by dedicated telephone service. To provide monitoring and equipment control on the twelve feeders, 75 locations were automated. Communications to the 75 locations is either dedicated telephone service (7), powerline carrier outbound and telephone service inbound (51), or powerline carrier outbound (17). The powerline carrier is a ripple control at 340 Hz. The automation system is controlled by a Digital Equipment Corporation PDP 11/44 minicomputer running the standard operating system and a specialized applications software system.

This paper covers the monitoring and control aspects of the automated distribution system, discusses operational benefits of the system and highlights two significant software programs that have been developed.

MONITORING REQUIREMENTS

Traditionally, utilities have operated distribution systems with minimal monitoring. Normally power, highest demand, voltage, current and reactive power are monitored with strip charts or magnetic tape devices. The data is usually not available except when the distribution substation is physically visited. Gathering and processing of data is limited to that essential to customer billing and to maintaining the system. The monitoring system provided when the AUB system was automated had a sampling rate of one sample per twenty seconds, and this was sufficient for day to day operations; however, it lacks sufficient data resolution for determining system perturbations resulting from automated capacitor

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control, voltage control, load transfers and load control. Specialized higher resolution equipment was required by the experimenters to eliminate the effects of normal load variations from the data. Sampling rates of five samples per second were temporarily provided to obtain the data required for discerning the transient response of automated control actions from the high frequency "noise" components of the load. This ability to separate normal system dynamics from the effects of control action is important to quantify the benefits of automation, develop control strategies and to verify their effectiveness. The higher resolution systems allow assessment of the effects of control actions within microseconds of the actions. The high resolution system is unsuitable for day to day operation because of the massive amounts of data collected.

Modeling of the distribution system and load forecasting models offer a possibility of reducing the level of monitoring required. The loads on the AUB system were found to be quite voltage sensitive and can only be modeled by higher resolution data. A system model combined with a load forecasting model can be used to determine the suitability of planned control actions and the length of time the control actions are feasible.

We predict that in the near future, automation systems will require on-line computer support and that with the application of artificial intelligence and expert systems, fast data acquisition systems will be used to monitor and control power systems.

MONITORING SYSTEMS USED IN ATHENS

Feeder level monitoring and end-use monitoring were used to gather data on the AUB system. Three monitoring systems were available for monitoring substation and feeder data: (1) the distribution automation and control system (2) a slightly faster monitoring system and (3) a high speed portable data acquisition system. Only systems 1 and 3 are described in the paper.

Two types of end-use monitoring systems were used. The first type was the Appliance Research Metering devices (ARMS) which gather four channels of energy and demand use data on appliances, interior household temperature and household watt-hour usage. These units were furnished by the Electric Power Research Institute and they monitored data at the rate of one to four measurements every five minutes or 288 times per day. The second type of end use monitoring is the smart meter which gathers total household energy use.

DISTRIBUTION AUTOMATION SYSTEM

The distribution automation system at AUB as shown in Fig. 1 consists of four subsystems: a central distribution dispatch control center, substation automation, feeder automation, and customer load control subsystems [2]. The central control center (CCC) which integrates the substation, feeder automation and load control systems consists of two PDP-11/44 computers and associated peripheral equipment. The man-machine interface to the computers includes dual color graphic display terminals, modems, printers, and data loggers. The real-time data acquisition and control software monitors and controls all field devices. Control commands are initiated at the CCC by the system operator, or, by real-time control software, such as the capacitor control program that is discussed later. The operator interacts with the real-time data base through the color display terminals. After, a control command has been issued, it is sent to a remote terminal unit (RTU) at the substation over a dedicated telephone line. The control signals are sent to feeder sites over telephone lines or by a signal injection unit that transmits a 340 Hz ripple signal over the power line. A control card in the RTU which has low current relays, responds to the control signal and activites a higher-ampacity "interposing relay". The interposing relay then drives the motor that either operates the feeder load-break switch, changes the feeder regulator tap position, operates a power recloser, or controls a capacitor bank oil switch.

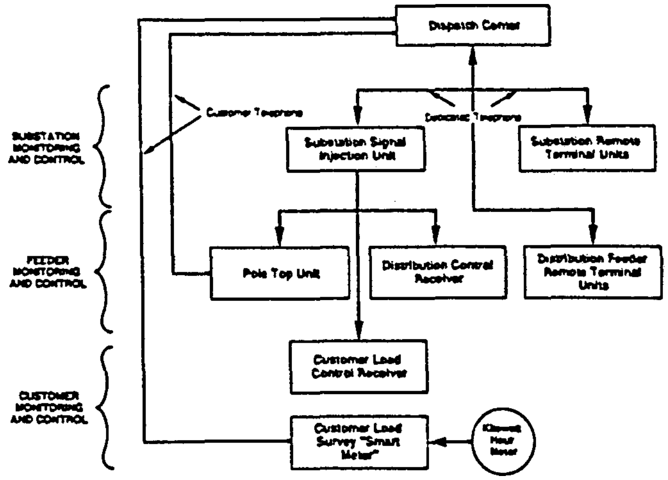


Fig. 1. Distribution automation system monitoring and control hardware.

The substation subsystem consists of three RTUs, one located at each of the three AUB substations. These units monitor real power, reactive power, voltage, transformer tap position, and breaker position along with weather data. The substation RTUs can monitor analog data at the rate of 1 sample every 20 s thus updating operator CRT screens at this rate; however the data is archived every 15 minutes. The feeder subsystem consists of 4 distribution remote terminal units, 51 pole-top units, and 15 distribution control receivers. The distribution remote terminal unit (DRTU), a smaller version of the substation remote terminal unit, monitors real power, reactive power, and voltage on all three phases and detects the status of fault sensors on the feeders. The pole-top unit (PTU) is similar to the distribution remote terminal unit except that it sends data to the dispatch center by a 300-baud customer grade telephone line. The pole-top units report when data is detected outside of preset limits and can be forced to report within approximately one minute. The PTUs share phone lines and if the line is busy, the pole-top-unit will reinitiate a call after 5 minutes. The distribution control receiver (DCR) is a one-way device that has no monitoring capability.

Substation Automation Subsystem: The monitoring and control functions for the three AUB substations are the traditional supervisory control and data acquisition functions. Both real and reactive power are monitored for each phase of each feeder. Single-phase voltages are monitored, as well as switch status and the position of various station and breaker relays. Substation breakers, capacitors, and regulating transformers are controlled and monitored, and temperature and humidity levels at the substations are monitored. In one substation, South Athens, a weather station is installed to monitor wind velocity and direction, barometric pressure, and solar radition in addition to the other weather data.

Feeder Automation Subsystem: Four types of devices on the AUB distribution feeders are monitored and controlled: load-break switches, power reclosers, voltages regulators, and capacitor banks.

Load-break switches isolate faulted overhead lines and transfer loads while the circuit is energized. Load-break switches are also used at "tie switch" points where two feeders can be interconnected so that one feeder can become the alternate supply source to the other feeder's loads. The load-break installations consist of a three-phase, group-operated switch and electric motor operator; in some cases, a battery backup for both the motor operator and the PTU; metal-oxide-varistor (MOV) surge arrestors; a fault-detection relay; and combination potential-metering/current-metering transformers (PT/CT) with bypass switches. Watt/var and voltage transducers in weatherproof cabinets are mounted at the base of the power poles. A PTU is mounted under the transducer cabinet.

Power reclosers transfer load and clear electrical faults (in coordination with the substation breaker). Power reclosers automatically reclose on the line for continuity of service for temporary faults and reopen if the fault is permanent. The power recloser installation consists of a Westinghouse type "PR" recloser, a normally open air-break bypass switch with six isolation disconnect switches, a PTU, and a transducer cabinet. Generally, a group-operated, three-phase air-break switch is used to bypass the recloser and other equipment on the pole. The power recloser installations are similar to the load-break switch installations; however, the recloser does not have a motor operator or a battery backup power supply.

The *Voltage regulators* are usually a transformer-type device with underload tap-changing capability to increase or decrease the load-side voltage. The voltage regulator installations consist of three single-phase regulators. A DRTU is mounted at the bottom of a pole assembly, and the transducer terminal cabinet is mounted above it. The voltage regulator RTU installation provides remote voltage regulator control and monitors the system voltage and power flows at that particular location. When computer-directed voltage control is required, interposing relays are used to bypass the local regulator control, and additional relays are used to remotely operate the voltage regulator tap changer.

Capacitor banks are installed on the distribution feeders to provide reactive power correction, thus minimizing the current flow in the feeder and reducing feeder power losses. Two different types of control schemes are used to control the capacitor bank installations: (1) a DCR for one-way control; and (2) a PTU for two-way control which controls as well as monitors the capacitor's state). The later scheme can be used in conjunction with metering of the distribution system power and voltage parameters. The capacitor bank installation consists of one PT/CT combination unit with isolation switches; MOV surge arresters; and a bank of capacitors with MOV surge arresters.

Customer Monitoring And Control Subsystem: Instrumentation installed in customer's homes includes 2000 load control receivers to control customer loads, and 200 smart meters to record the energy used and to communicate the data to the CCC. The load-control receiver controls customer appliances such as the water heater, central air-conditioning unit, or central heating unit. The smart meter monitors the whole-house load by reading the customer's kilowatt-hour meter. These whole-household customer load data are periodically transmitted back to the CCC via the customer's telephone circuitry. Load control uses power line carrier communication.

HIGH SPEED DATA ACQUISITION SYSTEM

It was determined that the monitoring capability of the AUB distribution automation system which has a sampling rate of 1 sample per 20 seconds was too slow to measure the short-term or immediate effects of control actions. Control actions, such as power factor correction, were noted to produce an increase in system load rather than the predicted reduction in load [3]. In order to investigate this phenomena further and in order to separate the effects of control actions on the system from normal system dynamic changes, a higher speed portable data acquisition system was developed. This system was used to monitor and record the system changes resulting from switching capacitors; from voltage control; from cycling of residential water heaters, space heating and cooling equipment; and load transfers between feeders. The data obtained by this equipment has been critical in developing a model of the AUB system. This system model can accurately predict the system response to the automated control actions. The data from the high speed acquisition system has been invaluable in understanding the effects of control on the AUB distribution system.

The high speed data acquisition system is a minicomputer-based system, developed by personnel in the Instrumentation and Controls Division at the Oak Ridge National Laboratory (ORNL). The system consists of a Digital Equipment Corporation PDP 11/23 minicomputer with a multi-user operating system, a 30-Mbyte fixed disk drive, a 10 channel 14-bit analog-to-digital (A/D) converter, filters to reduce band-width noise, an external trigger to set the sampling rate, software for data acquisition and post-test graphic analysis and cabling (Fig. 2) The cabling connects the system to watt, var and voltage transducers mounted in the substation. The system is portable and features 10 differential input signal channels with a data scan rate that can be set from 250 to 10,000 samples/second aggregate. The system is capable of recording 5 million samples (which is nearly 6 hours of data at the slowest sampling rate and slightly greater than 8 minutes of data at the fastest sampling rate).

After a test has been completed, the data are transferred from the fixed disk directly to another minicomputer for archival storage and via magnetic tape to a mainframe computer for analysis. Graphics programs that permit multiple channels on a single plot provide field analysis capability. Typically, measurements are taken for voltage (kV), real power (kW), and reactive power (KVar), both for individual phases and for all three phases simultaneously.

The system may be transported to the test site by a van or truck. Installation and wiring connections can be

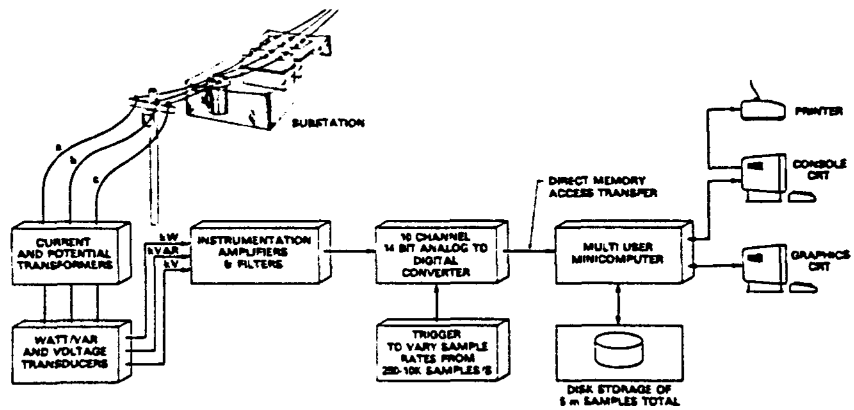


Fig. 2. Schematic diagram of high speed data acquisition system.

completed in about one hour. The signal inputs at the feeder are attached using quick-disconnect "clip leads", which connect to the existing voltage, watt, and var transducers at the substation circuit breakers. The monitored signals are prefiltered using 10 microfarad capacitors connected in parallel with the input signal from the transducers. Standard 50 ohm coaxial cables (RG 58) are used to connect the transducer cabinets to a mini computer, and each input signal is conditioned through a low-pass filter with a 10-Hz cut-off frequency to reduce signal noise. Inputs to the filters are differential inputs, which increases common-mode rejection, a feature especially important in the noisy environment of an electrical power distribution substation.

The outputs from the filters are connected to the inputs of the A/D converter. The data rate is set using an external triggering device connected to the converter, and an oscilloscope is used to monitor adjustments to the trigger rate.

The high speed system enabled the experimenters to easily evaluate the effects of control actions. By monitoring the switching tests with a resolution of 1000 samples per second, the natural variation in system load can be assumed to be constant. The high speed data system also allowed the analyst to develop an accurate load control model which can be used to predict the effects of control actions. A method of detecting appliance starts within the high speed data has been developed. The real time information may be used by the system operator to make decisions about load control actions [4].

A comparison of the data resolution of the two feeder monitoring systems described above is shown in Figures 3 and 4. As Figure 3 indicates the differences in real power, from one measured value to the next (less than ± 25 kW) are masked by load fluctuations which occur within a 20 second period. Differences in reactive power less than ± 10 kVar and bus voltages less than ± .02 kV are also masked. A significant improvement in data resolution is achieved when data are plotted from a higher speed data acquisition system (see Fig. 4). The resolution for data plotted at 1 sample per second, 10 samples per second and 50 samples per second are shown. The high speed monitoring system increases the data resolution from ± 10 kW for a 1 point per second sampling rate, to ± 5 kW for a 10 points per second sampling rate, and finally to ± 2.5 kW for 50 samples per second sampling rate. In most cases it probably is not necessary to monitor at sample rates higher than 1 to 10 samples per second to measure system perturbations for load modeling. The higher sampling rate has a similar effect on the data resolution of reactive power measurements. However, little improvement is achieved for monitoring bus voltage at a sampling rate higher than 1 sample per 20 seconds because the normal changes in bus voltage are on the order of ± .02 kV.

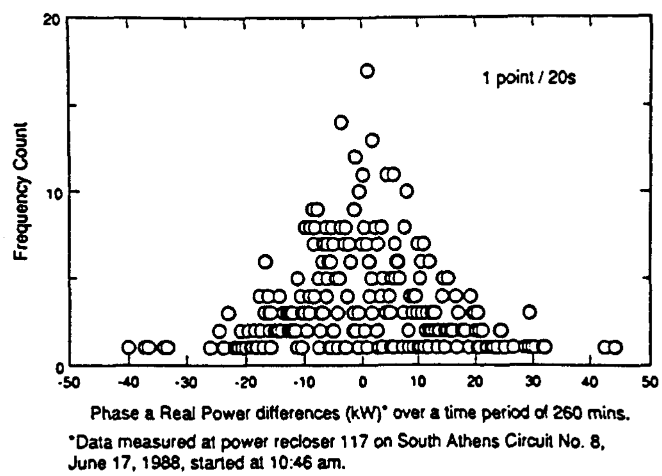


Fig. 3. Data resolution of distribution automation system which collects data at 1 sample every 20 seconds.

A large quantity of data is generated when using a high speed data acquisition system. At the present time, the equipment is not designed to provide information in real time. Thus, the analyst must locate the observations of interest during a control action from among the millions of observations.

It is currently not practical to install permanent high speed systems at all substations to monitor load control and the portable systems are used to verify control actions.

AUB OPERATIONS

The Athens Utilities Board has been operating the distribution automation system since January 1985. The system was initially instrumented to give extensive substation monitoring and control, feeder monitoring and control, and fault sensing abilities. AUB is gradually eliminating monitoring and control points not necessary for their day to day operations. The automated system has been primarily used by AUB personnel to determine equipment failure; for capacitor dispatch, for voltage control, for fault location and isolation, for load transfers, and load control and the system has provided some unexpected benefits as discussed below.

The objective of the originally installed monitoring system was to measure at least three system parameters at each monitoring location in order to calculate the remaining parameters. AUB has found it to be less costly if three watt/var and three voltage transducers are used instead of three current, voltage and phase angle transducers.

Prior to automating the system, billing information was used to determine to which phase new load should be added. The effect of new loads was checked by weekly readings of substation strip charts. The continuous monitoring of real and reactive power flow and voltage and the calculation of single phase current allow a continual check on each circuit's load balance and a determination now can be made as to which phase new load should be added to maintain a balanced system.

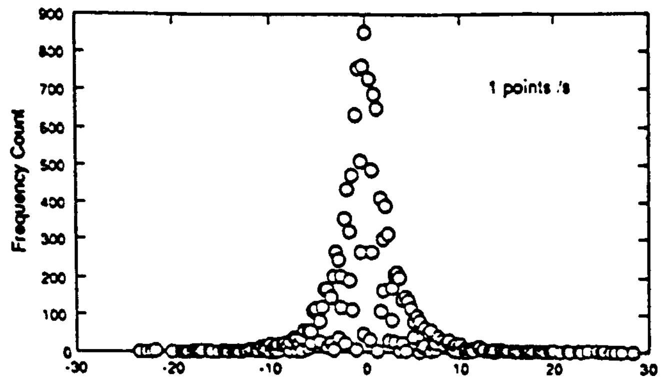
Continuous feeder monitoring at intermediate locations and transmission of the data to the central control room allow AUB to determine the section of a feeder on which load growth is occurring. The monitoring system can show startup currents and the trend (increase or decrease) in base current. Also, AUB has determined that it is not necessary to remotely control inline and intertie switches which do not have fault sensors.

Outages are detected by the automation system but some cannot be corrected from the control room. AUB uses a database to correlate customer phone calls with switch locations. They compare trouble calls from customers to determine the location and type of fault.

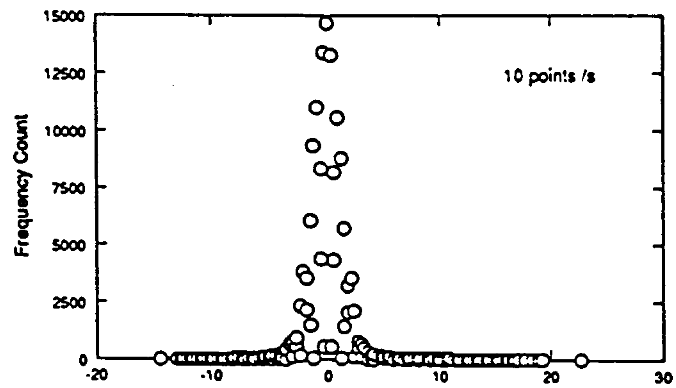
Voltage monitoring has been important during reduced loading conditions especially when capacitors are switched in. Prior to automating the system, only a few fixed capacitor banks were available. The new monitoring system has identified new locations for capacitor banks. This has been particularly important since TVA has now imposed a cost penalty if power factor on the AUB system is not held within close tolerances.

Since the start of the experiment, AUB has more than doubled the number of capacitors banks. Prior to automating the system, twelve banks were controlled by time clocks with a mechanical timer and by voltage control with high and low set limits. Eleven new capacitor banks have been installed for var control.

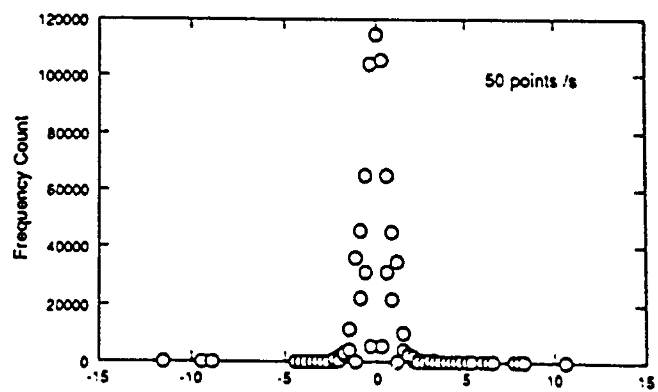
Two-way communication to capacitor banks has proved useful. One-way communication with capacitor banks which are monitored at the substation has been sufficient. A change in reactive power injection when a capacitor bank is closed or opened is easily detected by the substation monitoring system. Substation monitoring confirms that the capacitors at a remote site have been switched. Single phase monitoring on feeders has little value other than to provide voltage measurement at the end of the feeders and AUB has



Phase a Real Power differences (kW)* over a time period of 260 mins.
*Data measured at power recloser 117 on South Athens Circuit No. 8, June 17, 1988, started at 10:46 am.



Phase a Real Power differences (kW)* over a time period of 260 mins.
*Data measured at power recloser 117 on South Athens Circuit No. 8, June 17, 1988, started at 10:46 am.



Phase a Real Power differences (kW) over a time period of 260 mins.
*Data measured at power recloser 117 on South Athens Circuit No. 8, June 17, 1988, started at 10:46 am.

removed all phone lines to the single-phase monitoring points.

The load relief from turning off appliances cannot be accurately monitored using the slow speed monitoring equipment on the feeders. The number of appliances dropped at one time may be small and the natural variation in demand on a feeder between readings may mask the true amount of relief. It is therefore difficult to accurately determine the magnitude of load change due to switching out loads. Accurate determination of the amount of load dropped and restored can be accomplished with the high speed monitoring equipment. It is possible to track the response of the system to a load control action with the high speed monitoring. Monitoring equipment with a sampling rate of 5 samples per second is fast enough to track load control events.

Automated system reconfiguration operations normally performed on the AUB only involve load transfers from a faulted feeder to a supporting feeder to isolate a fault or from an overloaded circuit to relieve the overload condition. If the overloaded condition occurs on a frequent basis, a permanent reconfiguration of the circuit is performed. Automated system reconfiguration is not used by AUB to reduce peak feeder loads or to reduce feeder losses for the reasons described later in this paper, even though the monitoring and control functions do exist.

The distribution automation system at AUB will not decrease losses and peak loading because AUB is a relatively small system and the diurnal cycle of the loads on the 12 feeders are similar, the AUB feeders are "telescoped" so that any deviation from the nominal feeder configuration will increase the impedance between source and load, and automated switches installed at AUB are only sufficient to sectionalize feeders into three or four zones involving 25 to 33% of the feeder load per zone.

Frequent automated system reconfiguration operations will require an on-line assessment of the automated operation prior to its implementation and an assessment of how long the feeders can be reconfigured. The substation monitoring of the voltage and power flow injections of the AUB feeders and the monitoring of automated inline and intertie switches on the AUB system along with the *SYSRAP* program, a distribution automation applications program, which is described later are capable of this decision making. *SYSRAP* was developed by ORNL in order to predict the effects of a proposed automated controls action. In order to determine the length of time the feeders can be reconfigured, requires the incorporation of a load forecasting model into the *SYSRAP* program. However, since frequent reconfigurations will not decrease losses or peak loading on the AUB, it is not necessary for the operators to use the program on a regular basis.

MONITORING VERSUS MODELLING

Simulation programs such as *SYSRAP* which model the performance of the system under proposed control actions can be used to reduce the number of monitoring stations required. *SYSRAP* uses a feeder load model which incorporates data gathered at the substation and a knowledge of the distribution of load. The model assumes that all loads on the feeder are voltage sensitive and that there is no diversity between feeder loads. The program was validated by actual data taken during the control actions. Analysis of the data can show which monitoring points should be eliminated and which are necessary.

The substation data containing (real and reactive) power and voltage are necessary to determine the effects of control actions on the system. This information combined with aggregate information of the customer's loads is normally enough to determine the effects of control actions; however, monitoring at intertie switch locations can give more detailed information about feeder behavior.

There are two basic approaches to modelling load control actions. The first is to build a table(s) based on previously monitored control actions that estimate the impact of a control action. For space conditioning appliances, the table might include outdoor temperature, intensity of control, and the estimated load relief per unit controlled. Because water heating demand is seasonal and more behaviorally driven, a water heating table might include season, length of control action, time of day, and estimated relief per unit controlled.

A more sophisticated approach is to develop computer based models which make use of monitoring information. The monitoring information may be used either on or off line to update the models. These models utilize the same data as the tabular approach as well as other information. Sophisticated models for estimating the impacts of space conditioning control are based on duty cycle and/or thermal time constants.

Both methods of modelling the impacts of control share some common problems. The most fundamental of these problems is that the phenomena being modeled is constantly changing. In Athens, the use of space cooling appliances is increasing, the efficiency of replacement installations is increasing, and the demographics of the population and the associated usage patterns are changing. This means that the accuracy of any model will decline through time. Some utilities have reported large fluctuations in load relief from year to year. This reflects the system changes made over time, as well as changes in the reliability of the control equipment.

The system operator needs to know the available controllable load. However, the current state of the art does not lend itself to real time monitoring, prediction, and control. Thus, whole household and end-use monitoring is used to evaluate the impact of control after the fact and to construct and update models to predict the impacts of control. The use of high speed monitoring holds promise for being able to implement real time control in the future.

OPERATIONAL EXPERIENCES

The automation system at AUB has been in operation since January 1985 and AUB has gained over four years of operating experience. The system has an operator on duty 16 hours a day from Monday to Friday and 8 hours on Saturday. A standby supervisor is on-call when an operator is not on duty. Over the last four years, AUB personnel have gained confidence in the automation system and experienced the value of distribution automation in system operations. Some of the areas in which the system has been of benefit are described.

CAPACITY UTILIZATION

Experience in operating the distribution automation system has shown that the full potential and promise of distribution automation in improving capacity utilization is not realized in the AUB system. Automation equipment that is particularly relevant to capacity utilization enhancement includes the substation and feeder monitoring, 12 feeder circuit breakers, 12 power reclosers and 35 load break switches.

The AUB is a relatively small system and the diurnal cycle of the loads on the 12 feeders are very similar. At AUB, a load transfer to reduce peak load on one feeder necessarily increases the peak load on the supporting feeder.

AUB feeders are "telescoped" with conductor diameter decreasing and conductor resistance increasing in discrete steps with distance from the substation. The implication here is that almost any deviation in system configuration from the nominal condition will increase the impedance between source and load thereby increasing the losses, reducing the voltage and decreasing customer load. Distribution systems without telescoped feeders may have a greater potential to attempt loss reduction through feeder reconfiguration than is possible at AUB.

The number of automated switches installed at AUB is only sufficient to sectionalize each feeder into three or four zones. Consequently, even the smallest possible transfer of load from a feeder will involve a significant portion of the load on that feeder (25-33%). Fine tuning of the system configuration with respect to loss minimization and peak load reduction (with modest time diversity in feeder loads) would be a much easier task if smaller load transfers were possible. This would of course require more remotely controlled switches and increase the cost of the automation system. It should be noted however, that the reliability improvement at AUB due to automated fault isolation and service restoration tends to saturate at 3 to 4 zones per feeder as shown later in this paper. Thus if additional automated switches were added, their value would have to be based solely on the improvement in capacity utilization.

It was experimentally observed that load transfers at AUB are not conservative. That is, the relieved feeder generally sheds more load than is picked up by the supporting feeder. The decrease in load is due to the voltage sag on the transferred zone that results in a decrease in customer load that exceeds the increase in losses that was described above. Thus, load transfers between telescoped feeders can have a double drawback in that the losses go up and customer load (sales) goes down. Less voltage sag and less increase in losses might be achievable if smaller portions of feeder load could be transferred.

Load sensitivity to voltage was found to be an important factor in being able to accurately predict post load transfer conditions using a power flow program. Constant power load models were shown to yield inaccurate results while a constant current model agreed reasonably well with experimental data. Accurate models will be required to support operators in making switching decisions in highly automated systems where reconfiguration is a routine daily operation and load factors are high.

Feeder tie switches are seldom in their optimal location and significant transients can be observed once a tie switch is closed looping two radial feeders (as the first step in a load transfer). To avoid closing tie switches that would result in objectionable transients the differential voltage magnitude and phase across the tie can be measured (increasing the cost of automation) or an on line power flow can be used to predict the acceptability of the system state in the loop condition. This problem was not critical at AUB which is fed from a single supply point from the Tennessee Valley Authority.

While the capacity utilization improvements at AUB achieved through automation are not dramatic, the automation system has been successful in improving the reliability of service, ease of maintenance, and operating flexibility. A great deal has been learned about the characteristics of AUB which preclude substantial capacity utilization enhancement through automated switches.

MAINTENANCE ON THE AUB SYSTEM

Distribution automation has been used to control feeder breakers and feeder switches to deenergize an entire substation, feeder or feeder section for maintenance. This ability has greatly simplified and reduced manpower and time requirements needed to service or repair distribution equipment. To isolate the feeder or feeder section involves a two step process. First, the system operator opens the reclosing relay cut-out switch. The reclosing relay in a feeder breaker or power recloser serves to automatically reclose the breaker or recloser a specific number of times before locking out the interrupter due to a fault. The reclosing relay cut-out switch is opened to prevent the breaker from reclosing when switching is performed to transfer load and when linemen are working. Next, the system operator opens the feeder breaker and/or feeder load-break switches. While the system operator is deenergizing part of the system, the line crew is dispatched to the work site and proceeds to service or repair the system after confirming that the work site is deenergized. The ability to transfer load from one substation or feeder to a neighboring substation or feeder has ensured continuity of service to customers during the maintenance operation.

The ability to locate faults has greatly improved the dispatch of line crews during abnormal conditions. Prior to automation, several line crews would be send out to drive along side distribution feeders to look for blown fuses or open cutouts (which indicates an operation due to a fault). The automation system, in most cases, has eliminated the need to dispatch crews to look for the site of the fault. System operators use the automation system to determine the location of the service outage, normally within several utility pole spans, and to dispatch a line crew near to the site without having to spend extra manpower and time to locate the site of the fault.

The automation system has greatly improved the ability to perform complex switching operations. The repair of tap changers on the two LTC transformers at the South Athens Substation required AUB to transfer, on three successive nights, all of the load on the substation to the North Athens Substation. The first night the transfer was done without the use of the automation system. It required 2 hours and 13 minutes to manually execute all switching, 27 minutes to disconnect one transformer and involved fifteen people. The following two nights the load transfer was accomplished with the use of the automation system. Manpower was reduced from fifteen to ten to eight, and the switching times were reduced to 1 hour and 20 minutes, and 44 minutes, respectively for the two nights as confidence was gained in the automation system. This same load transfer has been made on two subsequent occasions to repair equipment damaged by lightning and the automated switching times have been further reduced to 18 minutes and 12 minutes, respectively [6].

PREVENTION OF EQUIPMENT FAILURE

The automation system has prevented the failure of the two Load-Tap-Changing Transformers (LTC) located at the South Athens Substation. The operators were able to observe at their console screens a substantial increase in the frequency of tap changes on both of the transformers. Typically, without distribution monitoring, it takes several weeks before a trend towards increased operations can be detected. An overhaul of one of the LTCs showed that a sensing unit was out of calibration resulting in the frequent tap changes, and both seal-in relays that ensure that the tap changers advance a full step were faulty. Since the two transformers are connected in parallel, the healthy LTC was operating along with the malfunctioning LTC, so as to stay within two steps of it. All contacts on the tap changers were damaged to the point of failure. The automation system saved the cost of replacing major LTC components, lost revenue and labor.

In another case, early in the morning on two consecutive days, the automation system recorded an instantaneous circuit breaker operation on the feeder serving a hospital. The hospital was temporarily transferred to another feeder and two other feeder sections were also temporarily transferred to neighboring feeders in hopes of narrowing down the area which was causing the breaker to operate. Three days later, another circuit breaker operation was detected on the same circuit. By narrowing down the search area, a failed insulator was found and replaced before it caused an outage. The hospital, a large shopping center, and a commercial sector were then transferred back to the original feeder which was now more reliable and stable.

POWER FACTOR CONTROL

TVA, the bulk power supplier, has recently changed the wholesale power rate to increase the penalty charge for poor power factor correction. A power factor charge is incurred when the system power factor is leading by 0.97 or lower during off-peak load demand periods and lagging by 0.95 or lower during on peak periods. Maintaining the system power factor within these limits has not been a problem. The automation system allows the system operators to remotely control feeder capacitors and to adjust the system power factor as load varies on the system. Prior to automation, some capacitors were controlled by time clocks and the others were fixed. Typically, the locally controlled and fixed capacitors resulted in sufficient power factor correction during peak load conditions but over correction during low load conditions.

The automation system can now determine when capacitor banks have failed to operate. When a capacitor bank is switched, a change in the reactive power at the substation is observed if the switching is successful. When a change in reactive power approximately equal to the capacitor kVar per phase rating is not observed on one or more phases, a line crew is dispatched to determine the problem. The correct operation of the capacitor banks is critical to maintaining a good system power factor.

RELIABILITY OF SERVICE

Distribution automation has improved the ability to restore service to customers following an abnormal condition such as a short-circuit fault. Prior to automation, the system operators relied solely on telephone calls from customers to report the loss of electric service. As part of the automation system, fault detectors have been placed at automated switch locations on the distribution system to identify and locate faults, and report the fault's location to the system operators at the dispatch office. Prior to the automation system, an area hospital installed a backup power system to maintain a minimal level of power during a service interruption. The ability to control feeder breakers and switches from a central location has made possible the remote transfer of loads, such as transferring the hospital from one substation or feeder to another during an abnormal system occurrence. In a number of cases, service has been restored to critical loads, such as the hospital, in less than five minutes compared to manual switching which used to take at least 30 minutes.

Analytical Reliability Study: The reliability effects of distribution automation on the AUB has been analyzed using a reliability computer code. Automation equipment that is particularly relevent to system reliability enhancement includes the substation and feeder monitoring, 12 feeder circuit breakers, 12 power reclosers, 35 load break switches, and 21 fault detectors. Automated fault detectors combined with remote control of distribution circuit breakers, power reclosers, and load break switches can significantly reduce the time required to detect and locate faults, increase the speed of isolating faulted equipment and provide faster load restoration above and below a faulted feeder zone.

The Predictive Reliability Assessment Model (PRAM), an EPRI-sponsored computer program, was used to calculate three industry-recognized reliability indices to quantify the effect of varying degrees of automated switching capability of the AUB distribution system [5]. Since automation costs are well known on the Athens system [6], it was of interest to determine the cost of incrementally improved reliability levels associated with various penetrations of automation equipment. Using the explicit perfect protection feature in PRAM (where the protection system always functions properly), it was possible to quantify the effects of feeder protection coordination and alternative remotely-controlled feeder supplies (interties) on feeder reliability. The results of analyzing AUB's South Athens Circuit No. 9 (SA-9) as shown in Fig. 5 are given below. SA-9 is mostly industrial and commercial, having the least number of customers and greatest kVA load of the three circuits on South Athens Substation.

Combining a structural description of the AUB distribution feeders with remotely-controlled and manual switch operating times, line-related failure frequency data, and customer interruption duration data, PRAM calculated the load-point reliability at each load on the Athens feeders. The calculated loadpoint results are combined by PRAM to determine the following three reliability indices for each feeder:

System Average Interruption Frequency Index

$$\text{SAIFI} = \frac{\text{total number of customer interruptions}}{\text{total number of customers served}}$$

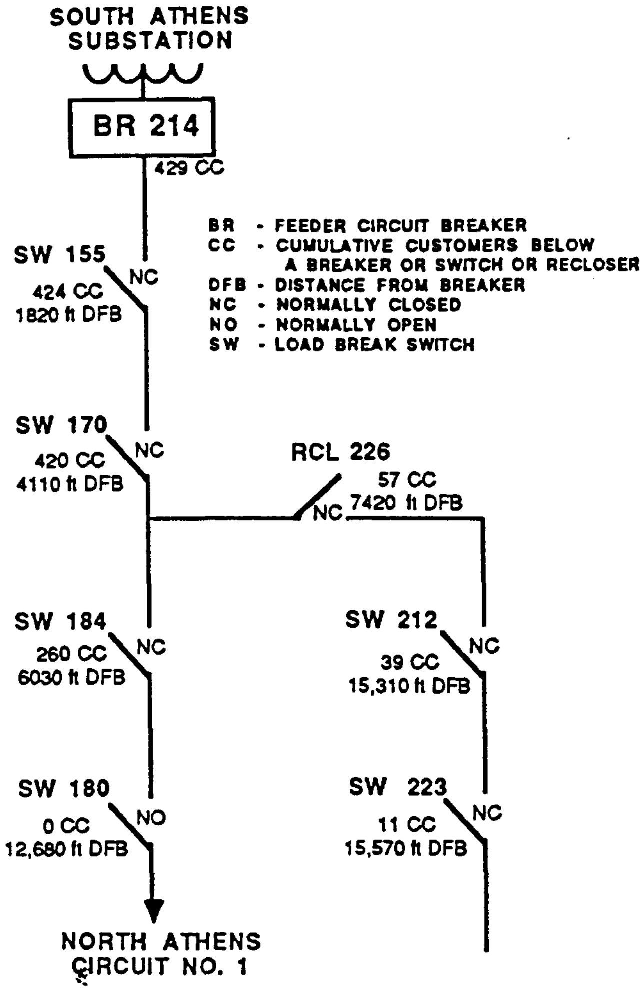


Fig. 5. One-line diagram of South Athens Circuit No. 9.

System Average Interruption Duration Index

$$\text{SAIDI} = \frac{\text{sum of customer interruption durations}}{\text{total number of customers}}$$

Customer Average Interruption Duration Index

$$\text{CAIDI} = \frac{\text{sum of customer interruption durations}}{\text{total number of customers interruptions}}$$

SAIDI, and CAIDI are highly sensitive to the switching time required to sectionalize and restore service after a fault. Hence, implementing remotely-controlled switches instead of manual switches results in an improvement in these reliability measures. SAIFI is a measure of the number of outages and is not affected by the penetration of automation equipment.

To analyze SA-9, one year's worth of trouble service summaries were examined. The total number of primary circuit outages was determined on all AUB feeders and averaged over the total distribution primary circuit miles to obtain a primary circuit failure frequency of 1.53 failures/year/mile. This failure rate was assumed uniform on SA-9 for the study. No attempt was made to account for weather, and minor outages caused by transformer fuse openings or secondary faults were not counted. Only the effects of automation on primary line reliability were of interest. During the course of the AACE, it was observed that restoring service using the automation equipment took, on the average, 3 minutes per switch, while manual switching requires approximately 20 minutes. Line repair generally takes 45 minutes for all but the most severe failures.

Four automation penetration scenarios were studied for SA-9 feeder. In general, the base case (scenario 1) involves all the protection equipment and switches shown on the SA-9 feeder one-line diagram operated in a purely manual mode, that is all switching times are set to 20 minutes. The second scenario is to automate the feeder breaker such that it can be remotely reclosed after fault repair. This is accomplished in PRAM by setting the breaker switching time to 3 minutes. Subsequent scenarios involve automating a switch pair consisting of one in-line switch and one tie switch. Such a pair will allow the feeder to be sectionalized (by opening the in-line switch) and a portion of the feeder to be transferred to another feeder in order to restore load (by closing the tie). PRAM assumes that any tie switch can support any load that might be connected to it. As with the feeder breaker, the automation of the switch pair is simulated in PRAM by changing the operating time from 20 minutes to 3 minutes. Additional switch pairs are automated until the feeder's AACE design configuration is reached. Typically any AUB each feeder can be remotely sectionalized into 3 or 4 zones.

The specific automation penetration scenarios for SA-9 are:

1. no automation
2. automate BR214
3. automate BR214, SW170, and SW180 (two zones)
4. automate BR214, SW170, SW180, and RCL226 (three zones)

Four combinations of manual switching time and line failure rate were investigated with PRAM. These combinations are:

A. 20 minutes, 1.53 failures/year/mile (the nominal values)

B. 40 minutes, 1.53 failures/year/mile (high switching time)

C. 20 minutes, 0.765 failures/year/mile (low failure rate)

D. 20 minutes, 3.06 failures/year/mile (high failure rate)

The reliability calculations are contained in Fig. 6. The figure confirms the expected improvement in distribution reliability from automation. All of the indices monotonically improve as additional automation is added but tend to flatten out when enough automation is added to have one automated in-line switch and one automated tie switch on each major branch of the feeder. The flattening of the curves suggests that a point of diminishing returns may be reached where adding more automated switching capability provides little or no benefit. Benefit/cost analysis is described below.

To conduct a cost/benefit analysis for the impact of automation on distribution system reliability requires three factors: the cost of automation equipment, quantifying the improvement in reliability through automation, and specification of the worth of reliability. While the cost of automation is well documented for the AACE [6] and the impact of automation on reliability indices is easily assessed using an analytical tool such as PRAM, the worth of reliability is highly controversial. Numerous studies have been conducted and published values on the worth of reliability, or equivalently the cost of outages, vary greatly. A summary of outage cost studies can be found in [7]. Table 1, from [6], which used the consumer price index in 1988 (3.507) and 1986 (3.284) to adjust equipment costs to 1988 dollars, shows the incremental cost of the automation equipment installed on SA-9. Using the table, the equipment cost for scenario 2 (automate BR214) is $10,455, for scenario 3 (automate BR214, SW170, and SW180) is $36,372, while the cost of scenario 4 (automate BR214,SW170, SW180, and RCL226) is $43,243.

We have not attempted to accurately determine the cost of outages for customers at AUB. Such costs would likely be as controversial as other published data and at best applicable only to the Athens Utilities Board. It is generally acknowledged that the cost of outages are highest in the industrial sector, although cost estimates still vary widely.

In order to demonstrate cost/benefit analysis we will use the short duration (1 hour) outage cost data for the industrial sector given by SRI in [7] to analyze SA-9. According to [7], the average outage cost for an industrial customer in the U.S. is $6.56/kWh with extremes of $3.21/kWh and $14.46/kWh (all in 1977 dollars). Using the consumer price index [8] in 1988 (3.507) and 1977 (1.815) to adjust these costs to 1988 dollars and assuming an average load of 6,000 kW on SA-9 (1986 kWh sales were 52,621,320), low, average, and high estimates of the yearly outage cost to customers on SA-9 (in 1988 dollars) are given by

$$6.20 \times \text{SAIDI} \times 6{,}000$$

$$12.68 \times \text{SAIDI} \times 6{,}000$$

$$27.94 \times \text{SAIDI} \times 6{,}000$$

respectively. Using these expressions and the cost data from Table I yields the cost/benefit analysis shown in Fig. 7 for 1.53 failures/year/mile, manual switching time of 20 minutes and automated switching time of 3 minutes.

The figure shows that even if we assume the lowest outage cost ($6.20/kWh) the automated cases appear to be fully justified on this feeder by the avoided customer outage cost. However the equipment costs shown in the figure represent only the incremental cost of added switching capability; they do not account for the basic system cost including SCADA and communications systems. While this example illustrates some key points, a comprehensive analysis should include the total annualized automation costs. Note

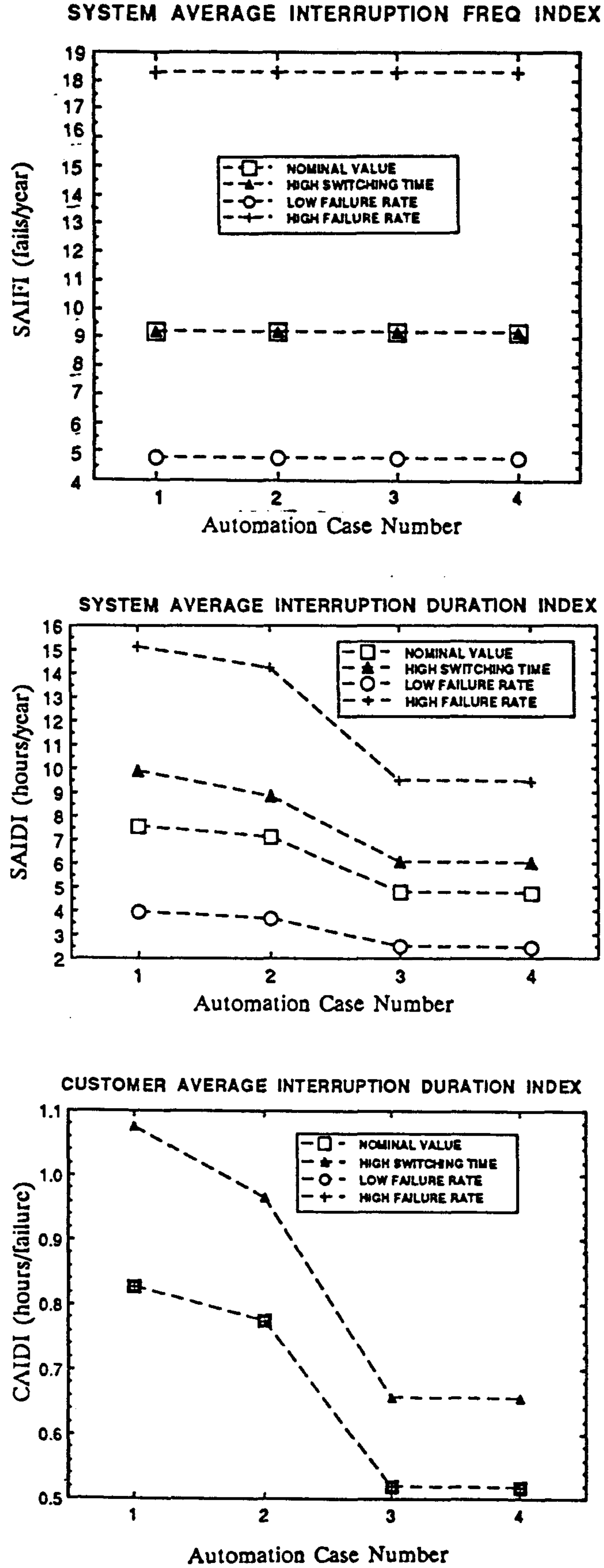


Fig. 6. Reliability assessment of South Athens Circuit No. 9 for increasing levels of automation.

that the customer outage cost given above are linear in SAIDI which is in turn heavily dependent on the historical outage frequency. If the failures/year/mile is halved to 0.765 (with manual switching times of 20 minutes and automated switching at 3 minutes) then the cost/benefits for SA-9 is that shown in Fig. 8 which clearly shows that the benefits of automation on reliability decreases with outage frequency. This result highlights the importance of using accurate historical outage data in making cost/benefit studies.

Table I. Remote switches and recloser costs on SA-9.

	Material Cost ($)	Labor (hrs)	Total ($) (@$35/hr)
BR214 (feeder circuit breaker) automated switching with status indication and three phase monitoring	3,560	197	10,455
SW180 (tie switch) automated load/break switch with status indication	6,935	51	8,720
SW170 (in-line switch) automated load/break switch with status indication and three-phase monitoring	11,842	153	17,197
RCL226 (recloser) automated switching and status indication (w/o recloser cost)	4,001	82	6,871

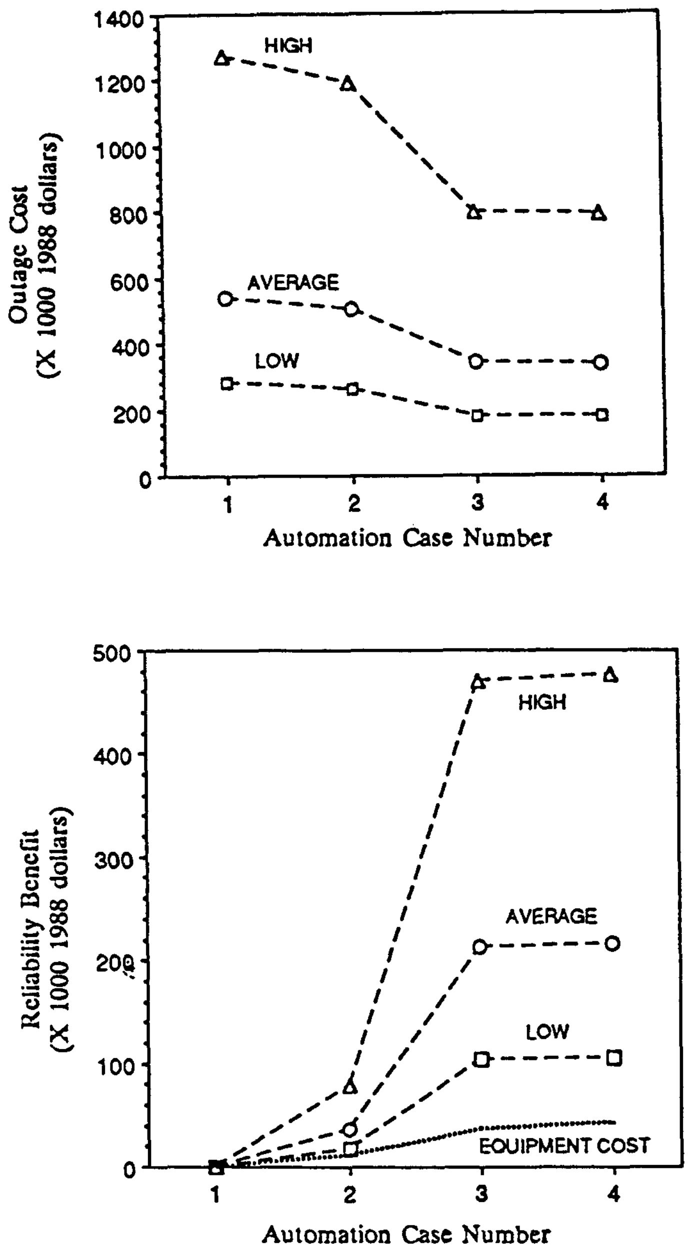


Fig. 7. Cost/Benefits for SA-9 assuming 1.53 failures/year/mile.

In summary, cost/benefit assessments to justify reliability enhancement through automation are conceptually straightforward. Such studies require accurate historical outage frequency data and an appropriate value for the worth of reliability. Since the worth of reliability is controversial, justification for automation based on reliability cost/benefit analysis will also be controversial. All of the indices monotonically improved as additional automation was added but tended to flatten out when enough automation was added to have one automated in-line switch and one automated tie switch on each major branch of a feeder. The flattening suggests that a point of diminishing returns may be reached when a feeder can be sectionalized into 3 to 4 zones and where adding more automated switching capability provides little or no benefit. The value of automation is shown to be highly sensitive to the historical outage data used to establish component failure rates and to the economic worth of reliability assigned by the utility.

<u>Operating experience:</u> Operation of the AUB automation system has shown that there are significant intangible reliability benefits and tangible cost savings associated with automation that are outside the scope of conventional distribution reliability indices. There have been several actual cases, where the automation system resulted in significant cost savings to AUB and reliability benefits that are not captured by conventional reliability indices. The automation system has enabled AUB to prevent outages or greatly reduce the outage area and number of customers affected, provide cost savings to AUB through the use of the automation system during daily and routine events that were normally performed manually, improve system safety, or detect failing equipment before a catastrophic failure of the

equipment and subsequent outage. The cases resulted in a direct benefit of $256,384 over a period of 30 months. These savings could not have been predicted by analytical studies, and as time goes on, other cost savings will add to the total.

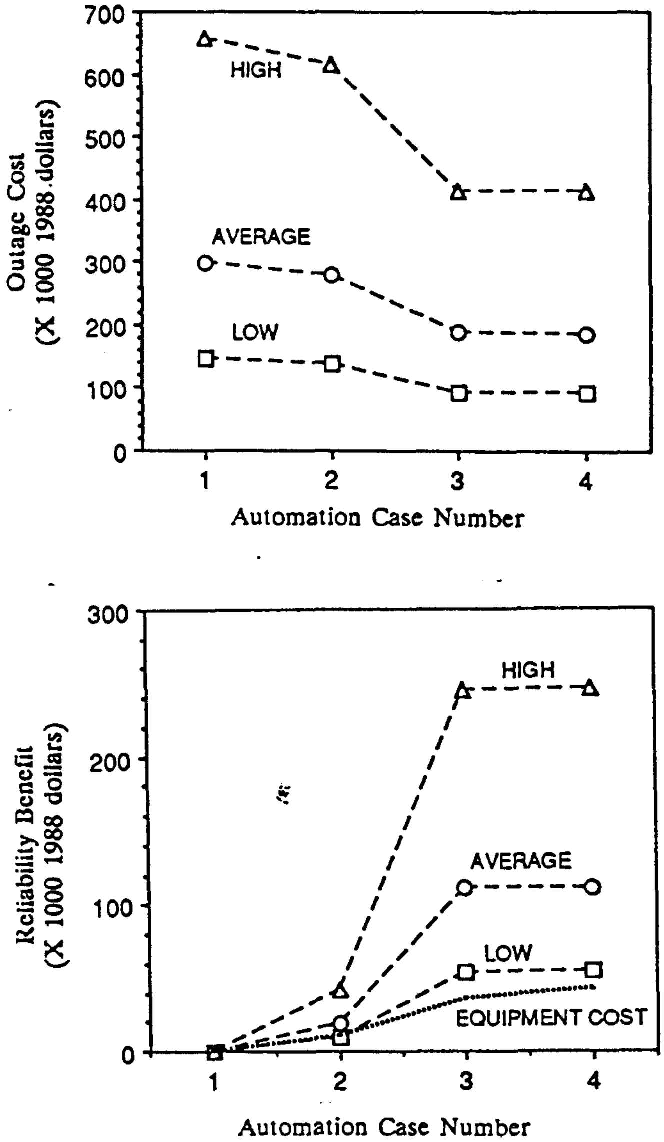


Fig. 8. Cost/Benefit for SA-9 assuming .765 failures/year/mile.

The value of automation in improving system reliability is understated if the value is determined solely from conventional distribution reliability assessment studies. Due to the more flexible operating environment made possible by automation, there are many opportunities for intangible reliability enhancements and tangible cost savings to be realized that are outside the scope of conventional reliability assessment indices. Many of the major benefits of an automation system result from the diagnostic ability to prevent small problems and outages from escalating into large outages. Other utilities should expect similar benefits, which will be difficult to quantify analytically but, which add to the value of and justification for distribution automation.

VOLTAGE CONTROL

At one substation, the automation system controls two load-tap-changing transformers (LTCs) and at another substation, the automation system controls voltage regulators located at various points on the feeders. The automation system continually provides the system operators with information on the system voltage supplied by TVA and the voltage at various points on the twelve feeders. TVA provides the voltage to the North Athens substation, the main substation for the system; however, the voltage along each of the feeders varies with customer load demand. The system operators have the ability to closely regulate the feeder voltage profile as the load changes during the day. Prior to automation, local controllers adjusted the settings of the LTCs and feeder voltage regulators. A better voltage profile has been maintained by using the automation system especially during peak load. Maintaining a level voltage profile ensures quality power to the customer.

SYSTEM PLANNING

The automation system has been found to be helpful in the planning of system changes. Recently, half of the system was reconfigured to relieve two feeders that were heavily loaded and to move the load to three feeders with surplus capacity. The two feeders were becoming overloaded and in fact one feeder was close to tripping out because of overload. The automation system is similar to a real-time load flow program. The system shows the real and reactive power injections for each feeder and substation and the voltage at the substation and along the feeder. The real-time information indicates when a reconfiguration of the system is needed to more equally load the distribution feeders.

The automation system has assisted in determining where capacitors are not necessary and where others are needed. Prior, to installation of the automation system, load flow analyses were conducted to determine where to place the controllable capacitors on the system. With the additional information provided by the automation system, it was later determined that some of the capacitor placements were not needed and that capacitors were needed in other locations. The system also determined that some of the capacitor banks were undersized and that larger banks were needed.

DISTRIBUTION AUTOMATION APPLICATIONS SOFTWARE

Two software programs that have been essential to the Athens Experiment are the capacitor control software and system reconfiguration and analysis (SYSRAP) programs. The capacitor control program automatically controls feeder capacitors on the AUB system to maintain a near-unity power factor. SYSRAP is a distribution automation analysis program that has been used to study system reconfiguration and volt/var control on the AUB system. Further, SYSRAP has been linked to the real-time distribution database of the distribution automation system.

CAPACITOR CONTROL SOFTWARE

A control algorithm was developed and programmed to determine when to switch feeder capacitors to maintain the lowest possible lagging power factor for a particular feeder as measured at the substation RTUs. A slightly lagging power factor was desired because AUB is penalized for leading power factor under the TVA billing system.

The software can be activated at timed intervals or in response to an alarm condition for reactive power. Alarm values for reactive power are set on each feeder according to the size of the feeder's smallest capacitor bank. Switching is determined by examining the end of the radial feeder and working back toward the substation, switching in or out capacitors as the total reactive power measurements dictate. Monitored reactive power at feeder sites away from the substation are used whenever they are available. In addition, a data file is updated each time a capacitor bank is switched, and the elapsed time is checked before the capacitor bank is switched again to prevent excessive switching that can damage the capacitor. The neutral current is also checked at the substation, because it was observed that the switching in of capacitor banks can increase the the neutral current and possibly trip a neutral overcurrent relay, resulting in the interruption of power at the substation.

Capacitor bank sizes and locations are contained in separate data files for each feeder, allowing the same program to be used for any feeder and simplifying capacitor bank size and location changes. The software was implemented on the AUB system in a transitional fashion to gain the utility operator's confidence. First, the software recommended capacitor switching operations via a special screen display on the operator's CRT. A capacitor bank was switched if the operator chose to do so. The software has since been extended to perform the capacitor switching operation by sending control commands to the capacitor banks.

SYSTEM RECONFIGURATION ANALYSIS PROGRAM

An innovative distribution automation applications software package called SYSRAP (System Reconfiguration Analysis Program) for assessing system reconfiguration, and volt/var control on the interconnected AUB radial distribution feeders has been developed [9]. SYSRAP is unique because it combines power flow and short-circuit analyses with data base management and is especially well suited for answering system operator questions with respect to switch orders, capacitor bank dispatch and regulator tap adjustments. The program runs on a personal computer, executes power flow and short-circuit analyses in tens of seconds and is adept at reorganizing the data base to reflect switching operations and changes in the status of volt/var control equipment. Feeder loads are modelled as voltage sensitive (any load composition of constant power, constant current and constant impedance). Experimental observations have shown that voltage insensitive load models (constant power sinks) are inadequate to accurately simulate system response to system reconfiguration and volt/var control which affect feeder voltage profile [9,3]. The loads are scaled based on specified total feeder breaker real and reactive power injections, bus voltage, billed kilowatt-hours and connected transformer kVA.

Functional Capability: *SYSRAP* provides the capability to study load transfers, capacitor switching, voltage control, and faults under various loading and temperature conditions. The program has been used to determine safe load transfers to perform on the system and to simulate load transfers that were felt to be too risky for experimentation. The program can perform six different distribution system studies: load transfer alternatives study, load transfer simulation study, voltage study, short-circuit study, post-fault load transfer study and capacitor dispatch study. *SYSRAP* maintains a database of input and calculated parameters that allows the operator to perform these various studies in an interactive fashion without extensive additional calculations (except when a reconfiguration or capacitor dispatch is performed).

The ***load transfer alternatives study*** was developed to identify candidate switch orders and provide the operator with answers to the capacity issues. A simple feeder-to-feeder load transfer involves two switch operations. A tie switch (normally open) between the two feeders must be closed and an in-line sectionalizing switch (normally closed) on the feeder to be relieved of load is opened to complete the load transfer to the supporting feeder. An operator has four primary concerns in developing a switch order for such transfers: what are the switching alternatives; is the conductor capacity adequate; will the voltage/loss profile be acceptable on both feeders; and will there be drastic changes in short circuit duty that may disrupt protection?

For each line section of each feeder, the data base includes the temperature dependent ampere capacity as calculated by the Schurig and Frick equations [10], and the through load (in amperes) based on the existing load condition. The difference, capacity minus load, is the "margin" which is the increment in through load that can be added to the section without overload. Since conductor capacity is temperature dependent, the user specifies an ambient temperature and the feeder from which load is to be transferred. The data base is then searched to identify all candidate in-line switches and the total ampere load below each such switch. The user selects one sectionalizing switch to be opened and a search is initiated to find all possible tie switches to be closed to an alternate feeder. For each tie switch, the "minimum margin" is located on the supporting feeder and the minimum capacity is located on the area to be transferred. The minimum margin is the smallest margin on any line section in the direct path between the tie switch and the feeder breaker on the supporting feeder. The location of the minimum margin is the potential bottleneck on the supporting feeder. The minimum margin must be greater than the total load to be transferred. The minimum capacity on the section to be transferred is also important because it also represents a potential bottleneck. After the transfer is completed the section that is transferred will be fed from the tie switch rather than from the in-line sectionalizing switch. Consequently the capacity of the conductor in the vicinity of the tie switch must exceed the total ampere load in the area to be transferred. This is an important consideration in systems which are telescoped, that is where conductor size decreases with distance from the substation.

When multiple tie switch options exist they are displayed in the order of largest to smallest minimum margin on the supporting feeder. If the minimum margin and minimum capacity values exceed the load to be transferred by a substantial amount (say 100 amperes or more), an operator may be sufficiently comfortable to execute the transfer without additional study. Other than the adjustment of capacity for temperature the procedure involves only data base searching rather than calculations and the total time required is a few seconds.

The *load transfer simulation study* simulates an actual load transfer from one feeder to a neighboring feeder by changing the normal feeder configuration and feeder database. The load is transferred to the neighboring feeder by rewriting the connectivity pointers for the affected feeders and a power flow analysis is performed for each feeder to determine new voltages, power flows and line losses. Pre and post transfer summaries are displayed to show the change in line power flows, losses, and minimum/maximum feeder voltages resulting from the transfer. After the load flow calculations are completed, a new set of margins is computed for the line sections on the feeders involved. For two feeders involving 300 nodes (50 nodes per phase on each feeder) the entire process requires 45 seconds on an IBM AT compatible with math coprocessor.

The *voltage study* was developed to provide fast approximate answers on the changes in voltage/loss profile that result from volt/var control actions or feeder reconfigurations. The existing voltage/loss profile from the substation to any desired point can be graphically displayed for any phase of any feeder. A control action is then specified, such as a capacitor switching or regulator tap adjustment, and the resulting voltage/loss profile is overlayed on the original. In executing this study the data base is not actually reorganized to simulate the specified control action. Rather the affected feeder is represented by about 5 line sections and loads are represented as pure constant current sinks. These simplifications allow the necessary load flow calculations to be executed in a matter of seconds.

Several unique features support rapid assessment of voltage/loss profiles associated with load transfers. An in-line switch on any feeder can be opened to simulate a load transfer to another feeder. The voltage/loss profile above the opened switch is then graphically displayed back to the feeder breaker. This feature is important since capacitor banks above the opened in-line switch may have to be switched out to avoid objectionable voltage increases following the load transfer. It is also possible to display the voltage/loss profile from an in-line switch on one feeder through a specified intertie to the substation breaker on a supporting feeder. This feature allows quick assessment of how much voltage sag will occur on the supporting feeder and the transferred section following reconfiguration.

The *short-circuit study* was designed to allow quick assessment of the effect of feeder reconfiguration on the settings and ratings of protection equipment. For each interrupting device on the feeder backbone it is important to determine how the normal load and short circuit duty will differ between the normal and the reconfigured state. The user can specify any location on a feeder and display the normal load (in amperes) and the short-circuit duty for that point when supplied in the normal feeder configuration and when supplied through an intertie from a neighboring feeder. Using this information, it can be determined if recloser relay settings need to be adjusted, if the rating of the interrupting device needs to be upgraded, how urgent it is to restore the feeders to their original configuration, or whether the feeders can be permanently left in the reconfigured state without compromising the feeder protection. This study mode executes quickly since loads are neglected in computing short circuit duties and since accumulated load data is stored in the data base.

The *post-fault load transfer study* was designed to assist operators in developing switch orders to restore service above and below a faulted line section. The user specifies a fault location and the program searches the data base for a set of automated in-line switches to be opened to isolate the faulted zone. Once the faulted zone is isolated, the fault clearing element above the faulted zone can be reclosed (if possible) and tie switches can be closed to restore service below the fault. All transfers are checked with regard to acceptable feeder margin on the neighboring feeders and capacity on the line sections to be transferred. A tabulation of total unserviced customers and load is maintained and alternative switching actions above and below the fault are identified.

The *capacitor dispatch study* can be used determine how to dispatch capacitors to move the power factor of a feeder closer to unity from a lagging or leading power factor condition. The package has been designed to display the low/high voltages, total line losses, total real and reactive power injection for a feeder and the status of all the capacitor banks on the feeder. When a change in capacitor status is indicated, the study procedure performs a power flow analysis to calculate the new low/high voltages, total line losses, and total real and reactive power injections. The pre- and post-capacitor switching values are displayed together for comparison allowing an operator or planner to determine if a capacitor switching is necessary to readjust the feeder power factor.

Power Flow Analysis: The power flow analysis method uses a modified approximation of the voltage drop equation to solve for bus voltages, line losses and power flows which results in fast and accurate calculations on a personal computer. The modified voltage drop approximation was compared with a fully complex Newton-Raphson power flow using the North Athens Circuit No. 5 data and a constant power load representation. The feeder was a 25% loaded, 10 MVA, three-phase circuit having 57 busses per phase. The test consisted of switching out all the connected capacitors on the feeder (3600 kVar) and running a load flow. The differences between the SYSRAP and Newton-Raphson results were less than .03% for voltage magnitudes, .006% error for line power flows, and .07% error for line losses. Using a voltage convergence criterion of .001 per unit, the SYSRAP algorithm converged 28 times faster than the Newton-Raphson power flow method.

Development: The present *SYSRAP* evolved in three general phases. The first phase of development involved the testing of algorithms that combine a radial power flow analysis, short-circuit analysis and data base structuring of input and calculated values in a data base management program. The initial data base structure specification and data base management system methodology greatly facilitated the addition of desirable automation features. Although the calculations associated with automation functions were not difficult, the data base size required minimization of unneeded calculations to achieve a satisfactory man-machine interface. In the second phase, the algorithms were written in a Pascal program and feeder data was dynamically allocated to system memory to speed computation and access times. During the last phase of development, the program was linked with the real-time data monitored by the distribution automation system at AUB so that *SYSRAP* could model the real-time behavior of the distribution system as closely as possible. These phases also reflect the evolution of personal computer technology over the past several years. The application vehicle during phase one was an eight-bit CP/M machine. In the second phase, a sixteen bit 4.7 MHz IBM XT was used. The code was implemented in real-time using an 8/12 MHz IBM AT clone with expanded memory.

Feeder Load Model: Experimental observations made on the automated AUB system have shown that the use of a simple load model, such as a constant power sink, is inadequate to accurately simulate system response to control actions which affect feeder voltage profile [3,9]. Such control actions include capacitor switching, regulator tap adjustments and feeder reconfigurations. For example, a constant power representation of loads predicts that the real power injection measured at the feeder breaker will decrease when a capacitor bank deployed on the feeder is switched in to move the feeder power factor from a lagging condition closer to unity power factor. Since the total power absorbed by the feeder loads remains constant with the constant power model, the predicted reduction in real power injected at the breaker is exactly equal to the loss reduction associated with the capacitor switching. Experimentally we have observed that the switching in of a capacitor results in an increase in total real power injection and corresponding increase in voltage at the feeder breaker as shown in Fig. 9. The explanation is that while losses are reduced by moving closer to unity power factor the feeder voltage profile improves which results in an increase in load that exceeds the amount of loss reduction. In order to make the *SYSRAP* simulator as realistic as possible, provision has been made to use highly detailed feeder models including voltage sensitive loads as outlined below.

Real-Time Experience: The use of *SYSRAP* by the system operators involves updating its database based on monitored voltages, total feeder breaker power injections, and the status of switches and circuit breakers collected by the distribution automation system. The use of voltage sensitive load models shows close agreement between the actual and computed voltages and power flows for load transfer, LTC transformer and capacitor switching tests conducted on the system [9].

Originally, *SYSRAP* was written as an off-line data base management tool to find logical groups of feeder line sections to switch for feeder reconfiguration. The PDP-11/44 computers at AUB were fully occupied by the real-time data acquisition and control software, which gathers and displays the data and implements the control functions. Hence, the computer was not available for application functions other than those requiring minimum memory and processing time. As a result, *SYSRAP* development began on a personal computer.

Using the high speed data acquisition system, a natural level of load noise of 5 to 10% was observed on the AUB system as shown in Fig. 10. Thus trying to obtain better than 5 to 10% agreement between the *SYSRAP* calculations and observed real-time data is not justified. The Athens distribution automation system was designed to respond to slow feeder load conditions. Hence, errors introduced by a slow scan rate, unsynchronized data measurements, transformer-load-management-based load distributions, and approximate calculation methods are tolerable as long as a

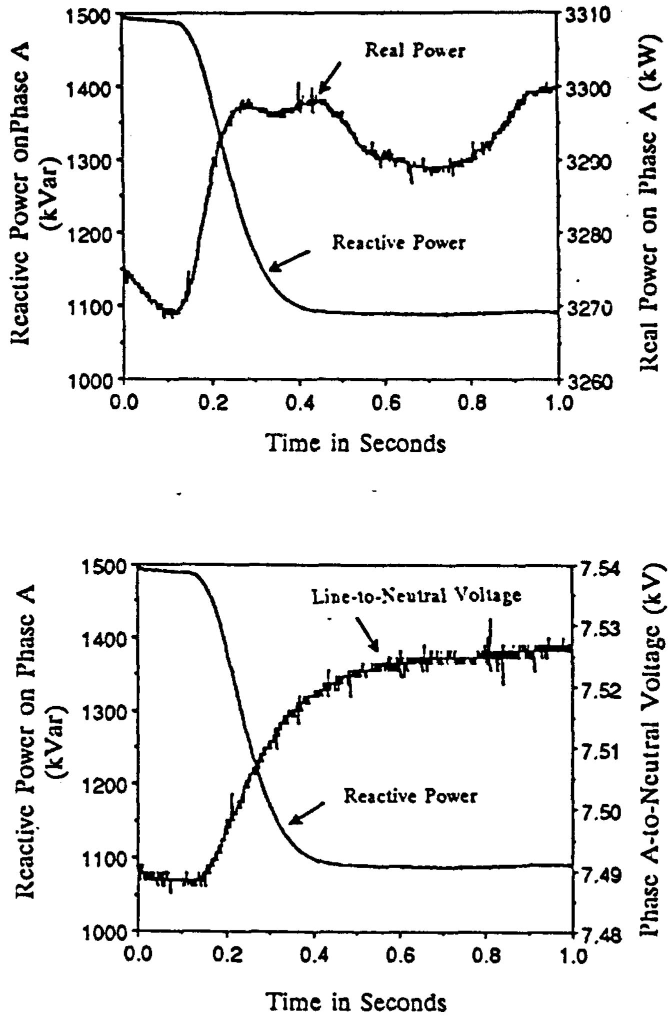


Fig. 9. Monitored real and reactive power and bus voltage for the switching in of a capacitor on SA-9.

means is available to periodically judge the severity of the error. While a portable high speed data acquisition system proved useful as a tool for calibrating distribution automation system measurements, checking the accuracy of the *SYSRAP*'s data base, and gaining confidence in both measured and calculated data, it was concluded that the twenty second scan rate feeder breaker data and the delayed remote monitoring point data was adequate for most distribution automation decisions.

CONCLUSIONS

Automation of electric distribution systems necessitates a higher resolution of monitoring of power flow, voltage, and equipment status than is normally used on distribution systems. When a system is operated near its capacity, load transfers in particular may need to be assessed prior to implementation to avoid overloading of conductors and loss of critical loads. A system can be designed to monitor every remotely and manually controlled capacitor, regulator, in-line and tie switch and circuit breaker to give a real-time power

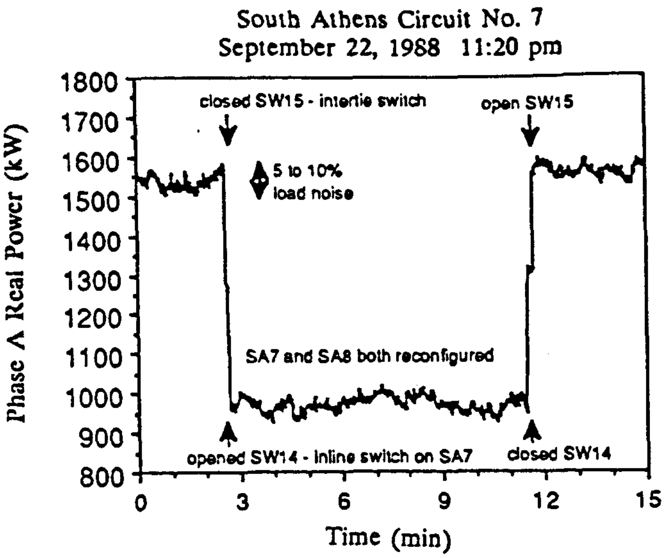


Fig. 10. Automated load transfer from SA-7 to SA-8 and back.

flow to the electric system every 20 seconds; however, a simulation program that models the performance of the system for automated control functions can eliminate the necessity for many feeder monitoring points. In addition, a load prediction model can be designed for a distribution system that can be used to determine the impacts of volt/var control, load control and system reconfiguration control actions before they are implemented.

The original instrumentation installed when the Athens system was automated is sufficient for the day-to-day operation of the electric system. The data resolution of the equipment provides the ability to monitor power and voltage changes due to capacitor switching, voltage changes due to voltage control, and voltage and power flow changes due to load transfers. However, the data resolution is insufficient for determining load changes due to load control and real power changes due to capacitor switching. Further, the resolution is insufficient for measuring switching transients due to load transfers which can momentarily overload conductors. Application of high speed data acquisition system was necessary to measure switching transients associated with load transfers and to determine the load sensitivity to voltage for model development.

The automation system has resulted in improved service reliability, improved system maintenance, improved voltage control over the total system, improved power factor locally and over the total system resulting in reduced power delivery costs, and improved system planning and capacity utilization for the Athens Utilities Board. Many of the major benefits of the system resulted from the diagnostic ability of the system to prevent small problems and outages from escalating into large outages.

The project has determined significant operational results. In general, automated load transfers on the AUB system do not result in loss reduction. Also, because of the sensitivity of customer load to voltage, load transfers are not conservative; more load is shed from the feeder being relieved of load than is picked up by the supporting feeder. There are significant intangible reliability benefits and tangible cost savings associated with distribution automation that are outside the scope of conventional distribution reliability indices.

Customer loads are sensitive to the voltage profile of the system and this load must be modelled accurately to quantify loss reduction. An improvement in voltage profile due to the switching in of capacitors can results in an increase in load that exceeds the loss reduction. Constant power load models traditionally used by utilities do not accurately model changes to the system parameters due to capacitor switching as well as load transfers.

Two software programs essential to the project have been developed. The capacitor control program provides automated control of feeder capacitors on the AUB system. A program called *SYSRAP* has been developed for analyzing distribution automation functions and linked to the real-time automation system. *SYSRAP* allows an operator to study the effects of planned control actions on the distribution system prior to taking action.

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