INTELLIGENT AUTOMATION SYSTEM FOR ELECTRICAL ENERGY DISTRIBUTION

Sanjeev Sharma 1, Sonia 2, Sushil Kumar 3
1 HOD EN, RDEC, Ghaziabad
2-3 EN Deptt., KIET, Ghaziabad

Abstract— In this paper, the functions that can be automated in distribution systems can be classified into two categories, namely, monitoring functions and control functions. Monitoring functions are those needed to record meter readings at different locations in the system, the system status at different locations and events of abnormal conditions. The data monitored at the system level are not only useful for day-to-day operations but also for system planning. Distribution supervisory control and data acquisition (DSCADA) systems perform some of these monitoring functions. Control functions are related to switching operations, such as switching a capacitor. The function that is the most popular among the utilities is fault location and service restoration or outage management. This function directly impacts the customers as well as the system reliability. This research work to be aimed at developing indigenous know-how of full scale Distribution Automation system, which can cover from secondary substations to consumer level intelligent automation, the power distribution automation is expected into broad areas. At present, power utilities have to need full scale distribution automation to achieve real time system information and remote control system. In modern power systems, the monitoring and control of power substations are based on the computerized Supervisory Control and Data Acquisition (SCADA) systems. The SCADA system monitors and control real-time systems. SCADA systems are the backbone of the critical infrastructure and any compromise in their security can have grave consequences.

Keywords: DSCADA systems, Power, Centralized Monitoring and Control, Performance Improvement, and Distribution Automation

1. INTRODUCTION

A power system consists of devices that generate, transmit, and distribute power. Power system automation is the act of automatically controlling the power system via automated processes within computers and intelligent I&C devices. It consists of three major processes, namely, data acquisition, power system supervision and power system control all working in a coordinated automatic fashion. Data acquisition refers to collecting data in the form of measured analog current or voltages values or the open or closed status of contact points. Power system supervision is carried out by operators and maintenance engineers through this acquired data either at a remote site represented by computer displays and graphically wall displays or locally, at the device site, in the form of front-panel displays and laptop computers. Control refers to sending command messages to a device to operate the I&C (A collection of devices that monitor, control and protect the system is referred as instrumentation and control (I&C) system) and power system devices, Fig (1).

The idea of distribution automation began in 1970s [1]. The motivation at that time was to use the evolving computer and communications technology to improve operating performance of distribution systems. Since then, the growth of distribution automation has been dictated by the level of sophistication of existing monitoring, control, and communication technologies, and performance and cost of available equipment. Although distribution systems are a significant part of power systems, advances in distribution control technology have lagged considerably behind advances in generation and transmission control. Small pilot projects were implemented by a few utilities to test the concept of distribution automation in the 1970s. In the 1980s, there were several major pilot projects. By the 1990s, the distribution automation technology had matured and that resulted in several large and many small projects at various utilities. [2] Some people expected that most of the utilities would come forward for large-scale distribution automation. However, many utilities found it difficult to justify distribution automation based on hard cost-benefit numbers. Business uncertainties due to deregulation and restructuring of the power industry slowed wide scale implementation of distribution automation. Thus, it is justified to re-examine the overall philosophy of distribution automation. It is time to
think small. Instead of a top-down approach, it is perhaps better for the utilities to opt for the bottom-up approach. Moreover, selection of distribution automation functions for implementation should always be need-based. Improvements of system reliability and voltage profile on the feeders are two examples of the needs for utilities. Need-based automation would be easier to justify and win approval of the management. [3] Distribution automation also provides many intangible benefits, which should be given consideration while deciding for implementation of distribution automation. After the deregulation and restructuring issues are settled, distribution automation activities should increase. As the electric power industry races towards a Smart Grid with a focus on Automatic Metering Infrastructure (AMI) and Demand Side Management (DSM), we need to remember the importance of reliability.

1.1 Literature Survey

Definition of distribution automation system, three different zones in which distribution automation is implemented and advantages of automation system [1]. Limitation of present automation techniques used in the field, challenges of implementing new technologies [2, 3]. Commercially available devices for distribution automation purpose are listed as [4-6]. As the technology advances, there are possible solutions to develop advanced distribution automation system. The requirements and implementation of Advanced Distribution Automation (ADA) is explained in [7, 8]. New approach of using IEC 61850 at distribution automation level is discussed [9].

2. BENEFITS OF DISTRIBUTION AUTOMATION SYSTEM IMPLEMENTATION

The benefits of distribution automation system implementation can be classified in three major areas are as follows:

Operational & Maintenance benefits

1. Improved reliability by reducing outage duration using auto restoration scheme
2. Improved voltage control by means of automatic VAR control
3. Reduced man hour and man power
4. Accurate and useful planning and operational data information
5. Better fault detection and diagnostic analysis
6. Better management of system and component loading

Financial benefits

1. Increased revenue due to quick restoration
2. Improved utilization of system capacity
3. Customer retention for improved quality of supply

Customer related benefits

1. Better service reliability
2. Reduce interruption cost for Industrial/Commercial customers
3. Better quality of supply

2.1 Distribution Substation and Feeder Automation:

It is generally applied to that element of the distribution system which operates at voltages above 22 kV. Distribution substation and feeder automation also referred to as Primary Distribution automation. Different functions of Primary Automation Technique are listed below:

1) Transformer Load Balancing: Transformer load balance monitoring provides remote access to near real-time information concerning the overall operation of the distribution system. This information can be used on a daily
basis to verify the effects of other down line events such as capacitor switching, residential load control, and recloser operations. It is also useful on a periodic basis to fine tune the efficiency of the Utility's power distribution configuration.

2) Voltage Regulation: This feature of DAS offers utility personnel the ability to reduce line voltage during peak demand times by remotely taking control of the Load Tap Changer. It also facilitates the remotely boosting of line voltages above the local LTC settings in case of emergency situations such as back-feeding.

3) Fault Isolation and Sectionalizing: Remote monitoring of the recloser operation to the melting of a fuse link, utilities can detect the fault very fast and can take quick action to clear that fault. Even during the outage of the power supplies distribution automation devices on that line can report the data remotely. By correlating the last voltage or current measured before an outage from several points along the distribution system, an indication of the nature of the fault as well as its approximate location can be obtained.

4) Remote Interconnect Switching: Distribution automation systems can be deployed to drive remotely interconnected switches that separate different portion of the utility distribution feeders. By the use of remote interconnect switching utilities can manipulate their distribution system to provide the most efficient configuration and also will able to remotely restore power to as many consumers as possible during the time of multiple faults.

5) Capacitor Bank Switching: It is most commonly deployed automation technique in a distribution network. The most cost effective capacitor control configuration is to install a number of one-way receivers at the capacitor locations for positive control and to monitor the aggregate effects of the capacitor switching at the substation low voltage level bus. Utilities with capacitor bank switching facilities can operate with reduced losses and as a result with higher efficiency.
6) Voltage Monitoring: By monitoring the feeder voltage remotely utility personal gets advance notification about the line voltage drop due to high usage. Also recorded data of feeder voltages will give snapshot of the actual usage patterns.

2.2 Consumer Location Automation:

Consumer location is the most challenging application area for the distribution automation system as large numbers of installation points are required and all the points should be economically viable:

1) Load Management: Load management is achieved by local appliance control. It consists of a utility activated relay that interrupts the power consumed by non-critical loads such as water heaters, air conditioners, electrical heaters, pool pumps, etc.

2) Automatic Meter Reading (AMR): For utilities, AMR is one of the cost effective way to read the residential kilowatt-hour meters. The AMR device can be initially programmed to report back to the utility based on a schedule or some pre-set usage level. Modern AMR devices incorporate the capability of remote reconfiguration of operating parameters and schedules.

3) Demand Side Management (DSM): An extension of automatic meter reading technology is the DSM application using Real Time Pricing. This application includes the functionality of monitoring the power usage during specific periods of the day as well as the control functionality of notifying the customer of the change of periods and the new rate for that period. For some utilities, this option is not cost effective.

4) Quality of Service (QoS) Monitoring: Quality of service is different things to different utilities. The most comprehensive definition includes monitoring power outages and its duration, the track record of power disturbances (such as voltage blinks, harmonics and voltage sags), and monitoring voltage wave-form distortions.

3. SCADA SYSTEM

A SCADA system generally consists of a master station and a number of geographically dispersed Remote Terminal Units (RTUs), all interconnected to master station via a variety of communication channels (Figure 2).

![Image](Fig. 2)

3.1 Remote Terminal Unit

Microprocessor based substation and pole-top RTU has been designed and fabricated using standard off-the-shelf cards. The RTU is modular and has 24/48/54 analog and 24/48/96 digital I/O channels, and affords bidirectional data communication as depicted in Fig. 3. The acquired data (voltage and current) are processed for rms and power factor calculations. Some design goals focus at low cost, flexibility and expandability, modularity at signal conditioning level, and communication interface. The developed RTU has a capability to exchange the information with Intelligent Electronic Devices (IEDs) such as IED meter and IED relays.
3.2 Communication System

Communication system enables distributed data acquisition, monitoring and control system functions. Unlike traditional communication solutions, the approach adopted here is to have a core communication controller at the DCC that can support diverse choices of communication media (dialup, Ethernet, WLL, GSM) as shown in Fig. 6. This open approach facilitates cost effective implementation. The communication controller has cross-platform portability, supports functions for communications network management, and permits LAN, Internet, and Intranet connectivity through Ethernet. All the control command functions are invoked through Graphical User Interface (GUI) of DA software. Data transfer between DCC and RTUs supports Distributed Network Protocol (DNP-3.0), which is the industry standard open protocol.

3.3 Substation IEDs and Protocols

A pole top RTU is required at each distribution transformer and a panel mounted RTU is required at each distribution substation for the purpose of their computer aided monitoring and control. These RTUs need to
communicate the data with the Distribution Control Center (DCC) and Intelligent Electronic Devices (IEDs) available at the site. Examples of IEDs are electronic meters and relays with data communication interface. The existing IED meters and relays have been utilized to retrieve the analog and digital information by the RTUs to reduce the instrumentation activities. The other analog quantities and digital information, which are not retrieved directly from the IEDs, are taken through the Input/output interfaces of the RTU. This requires installing additional instrumentation between RTU and power distribution components such as transformer and feeders. Also, the RTU has provision to send the control command to the actuator of a switching element through the IED relay if available at the site.

3.4 Distribution Automation Software

The DA software has the following components: (i) Distribution network software with attributes like graphical representation of network, cross-platform portability (Windows NT, Linux, Solaris), editing features, customizing, network validation, system topological information, component specification, and billboard printing; (ii) Set-up utilities for installation on different platforms; (iii) Automation software having real-time features, cross platform portability, alarm generation (audio/video), system monitoring (of system quantities, equipment health and switch status), switch control commands, control interlocks and event log report; (iv) Database with real-time attributes that conforms to a library format, uses shared memory approach, provides interface for backup in standard databases for all off-line applications, permits sharing of data in multiple processes, and has registry access for security and RTU identification; and (v) Application software which includes packages for network re-configuration, load shedding, volt-var control through capacitor switching, and fault detection and isolation.

3.5 DSCADA

Distribution supervisory control and data acquisition is commonly taken to mean the chain of equipment which
1- Collects the status and measured system and other data at substations, codes, and transmits this to the control centre, processes and display the results to the operator, and logs select item.

2- Enables instructions on status and output of the consumers to be sent to the substations for implementation automatically or by the local operator.

3- Energy management system comprises the hardware and software provided for computational support on-line power flow, voltage profile load prediction, unit commitment, optimization, etc. Figure-4 observe the main elements of distribution supervisory control and data acquisition.
Different components of Distribution Automation System have been indigenously designed, developed and successfully implemented at the pilot level under the mission mode project on Power Distribution Automation. This paper has presented a brief description of SCADA systems and has outlined some of the capabilities of such systems over and above supervisory control. The application of digital computers to such systems has provided very powerful tools for system dispatchers, so that they can be kept aware of system status and can also be provided with automatic logging, automatic generation control, and other applications considerations.

REFERENCES