FEATURES AND BENEFITS OF MODERN DISTRIBUTION MANAGEMENT SYSTEMS

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INTRODUCTION

Distribution networks have traditionally been the poor cousins of the high voltage (HV) transmission networks as far as centralized SCADA control is concerned.

For many years it has been accepted that as a minimum SCADA monitoring and supervisory control is an absolute necessity for operation of a transmission network. Furthermore today most dispatching centers for HV transmission networks have an Energy Management System (EMS) which, in addition to basic SCADA capability, also have advanced application software for modelling the HV network and performing State Estimation, On-line Dispatcher Power Flow, Contingency Analysis and even optimisation applications.

Meanwhile, at the distribution level there still are many distribution utilities around the world which do not have any form of SCADA or computer-based distribution management systems. The reason for this disparity between transmission and distribution system control is easy to understand and explain.

First of all, in a distribution network generally the impact of a network outage or other operating problem is relatively limited in terms of the number of customers affected by an outage. Thus the "benefit" of computerized investment generally is less. Secondly, generally the size of the distribution network in terms of the number of power system devices such as circuit breakers, sectionalising switches, fuses, etc. is very large. Therefore the total number of automation devices, e.g. Remote Terminal Units (RTUs), required on a distribution network is generally much larger than on a transmission network. For example, the PEA distribution network in Thailand will have over 2000 feeder RTUs in Phase 1 which covers only 5 of their 12 areas.

However, for several reasons, the situation is beginning to change, Most importantly, it is becoming increasingly important to customers to get reliable supply of power with fewer interruptions of supply and more rapid restoration of power when outages do occur. With the move toward de-regulation regulatory agencies are forcing utilities to provide higher quality of service, often with financial penalties for poor performance.

At the same time, with the improved price-performance of modern electronics, micro-processors, computers and communication technology, the cost of automation has decreased significantly over the last decade.

The end result is that large scale distribution automation and management technology is becoming both increasingly important and economically viable.

There are three main components in an automated distribution system:

- Field devices, including remotely controlled switches, digital relays, and other intelligent electronic devices.
- Communication systems, including radios, fibre optics, WAN/LAN technology and remote terminal units (RTUs)
- Control and Dispatching Centers, including SCADA systems, Outage Management Systems (OMS) and Distribution Management Systems.

This paper is concerned primarily with the various types of Control Center systems and especially Distribution Management Systems.

COMPUTER-BASED SYSTEMS USED IN DISTRIBUTION OPERATIONS

There are various types of computer-based systems which are commonly used by distribution operations. These systems have some common characteristics which, superficially, make them look very similar to each other. Three of these systems, all of which are used to some extent in real-time operations - are briefly described in the following.

Geographic Information Systems

Because of the large size of most distribution networks, the distribution utility must maintain a large volume of data or records about their network, including many drawings. Indeed the common characteristic of most distribution dispatching centers is the large number of cabinets of drawings, and not infrequently most of the walls of the dispatching rooms are covered with drawings of the network.

Prior to the use of computers, these records were maintained manually in paper form. When computers were first introduced in this area of electric power utilities they were primarily known as Automated Mapping / Facilities Management (AM/FM) systems. Today the term Geographic Information Systems (GIS) is more common. GIS is a generic computer industry term for database management systems primarily concerned with data that has a significant spatial or geographic component.

Over recent years many distribution utilities have made significant investments, with varying degrees of success, in acquiring GIS systems and converting their paper based records and network drawings into GIS form. Once these GIS systems exist it seems natural to want to use them directly in real-time operation of the network.

However, in my opinion, unfortunately most GIS systems are not suitable as the primary platform for real-time distribution operations. GIS systems are designed primarily for their off-line records management role. In particular their user interface tends to be optimised for the data entry and editing task, not for rapid display call-up and navigation. Also, most GIS systems are not intended for 24-hours-per-day, 7-days-per-week operation, which is what is needed in the real-time operations environment.

Another commonly occurring problem with GIS systems, in our experience, is that the GIS data is captured primarily for asset management purposes, with only a graphical representation of the electrical connectivity. To be useful for subsequent analysis of the electric network, it is essential that the electrical connectivity of all the devices in the network be explicitly modelled in the GIS databases.

Outage Management Systems

Outage Management Systems (OMS) appear to have arisen first in the North American context, where with some significant exceptions, most distribution networks traditionally have had relatively little automation. In the typical distribution utility where SCADA telemetry exists at all, it generally exists only at the distribution substation. Quite frequently, the substation SCADA monitoring is done by the transmission operations and distribution operations may have some limited access, for example, via remote consoles.

In the past, and to a considerable extent today, it is not uncommon for there to be no real-time telemetry outside the substation, in which case the primary source of real-time information regarding problems on the distribution network is telephone calls from customers reporting, or asking about, power outages affecting them. Typically such calls from customers are received by the customer service department which, in the past, would write a paper "trouble ticket" and pass them on to the operations department for resolution.

In a large utility, management of trouble tickets, particularly under storm conditions becomes a monumental task. In general a number of customer calls may pertain to a common network problem. For most efficient dispatching of trouble crews, the trouble tickets must be sorted and grouped into suspected common outages to minimize the likelihood of dispatching multiple crews for a common network problem. Furthermore, the dispatcher must try to prioritise the suspected outages so that crews can be dispatched to the most critical or the largest outages first.

It is in this environment and to address this particular task, that Outage Management Systems (OMS) were initially developed. OMS are designed specifically for the real-time operational environment. Furthermore, to perform their work of grouping customer trouble calls, and determining the size and impact of distribution outages they need a connectivity model of the network, including the switches and protective devices as well as a mapping of individual customers to their network attachment point, usually the MV/LV distribution transformer. An OMS system usually will include a full graphical representation of the network.

However, most OMS do not purport to manage real-time telemetry or remotely-controlled switching operations on the distribution network. While they may accept switch status information from SCADA systems to perform outage tracking and management they do not address the full range of real-time distribution network operations.

Distribution Management Systems

A distribution management system (DMS) is defined as a complete computer-based system used by a distribution dispatcher to manage all aspects of real-time network operations. It provides to the dispatcher a continually updated view of the distribution network based on all available information, including real-time SCADA telemetry, as well as information such as customer reported outages, manual switching operations effected by field crews.

The following paragraphs summarize some of the most important characteristics and capabilities of a modern DMS.

Performance. A DMS is based on a SCADA platform with all of the real-time performance expected by dispatchers of electric power networks. Full graphic displays of the network should be accessible to the dispatcher in the order of one second.

Availability. A DMS must provide reliable operation 24 hours per day, 365 days per year. This can only be guaranteed with dual-redundant architectures with the capability for automatic fail over.

SCADA. A DMS should have a full range of traditional and advanced SCADA functionality with the ability to monitor and issue supervisory controls via substation and feeder RTUs. It should support the industry standard RTU protocols such as DNP and IEC870-5. It must be able to interface to a variety of communication media, in particular radio, as well as IP-based wide area networks.

Network Model. A 3-phase model of the electrical distribution network is essential. This model must include electrical connectivity as well as network impedance and customer loads. All conducting equipment such as switches, breakers, fuses, overhead lines and underground cables, transformers, capacitors must be modelled.

Full Graphics. The user interface is perhaps the most important feature of a DMS since it is essentially the sole mechanism for the dispatcher to perceive the state of the network as determined by the DMS. Full graphics capability, including pan, zoom and de-clutter, is essential for representation of geographical displays of the distribution network overlaid, for example, over maps showing streets and roads. At the same time, schematic views of the network should also be supported in parallel with the geographic views

The GUI must be expressive by having a variety of ways, such as coloring, to convey the current state of the network. It must provide intuitive and efficient ways to navigate through the large number of displays available. Above all it must have high performance response to user requests.

Connectivity Analysis. The model must have Connectivity Analysis capability which can rapidly and efficiently in real-time determine the live-dead-grounded status of each network element whenever any switching action is performed. In addition to recognizing connections via switching actions, it should also recognize temporary network connectivity changes via cuts and jumpers and grounding achieved via portable grounds. A variety of network tracing functions must be supported, including upward tracing from multiple customer reported outages to determine common suspected outages.

Load Flow. This application automatically computes the estimated 3-phase unbalanced voltages and currents throughout the network based on customer load profiles and the results of the connectivity analysis application. Where real-time SCADA telemetry is available, load estimates must automatically be scaled such that the current flows calculated by the load flow match the telemetry.

Switching Advice. The DMS should have tools which can be used by the dispatcher to quickly and efficiently determine the optimum switching actions to restore power to outaged areas when the normal supply path is unavailable or to transfer load to neighbouring feeders to relieve overloads.

Fault Management. Whenever there are uncommanded breaker trips due to faults on feeders, the DMS must have the ability to automatically and quickly analyse fault current passage data from RTUs on the feeder to determine the location of the fault. It must then be able to determine optimum switching actions to isolate the faulted section and to restore power to unfaulted sections of the feeder both upstream and downstream of the faulted section.

Switching Orders. A great deal of the distribution dispatcher's workload consists in the creation and supervision of switching orders, usually in support of maintenance and construction activities by field crews. Therefore a modern DMS should include a computer-based switching order management facility which will support creation, validation and execution of switching orders. This facility should be linked to the switching advice and fault management subsystems. The user interface must be at least as efficient as the paper-based systems used in the past.

Trouble Call and Outage Management. The DMS must have capabilities to perform the trouble call and outage management functions of an Outage Management system, as described above.

Dispatcher Training Simulator. A modern DMS should include a dispatcher training system (DTS) which can be used to train new dispatchers and provide refresher training for experienced dispatchers on how to best operate and manage the distribution network via the advanced facilities of the DMS. The DTS trainee environment should be as near as possible to an exact replica of the hardware and software of the real-time DMS. In addition it should have special tools to allow an instructor to define realistic training scenarios including equipment malfunctions.

DMS BENEFITS

A modern DMS provides benefits in many respects to the distribution utility. The following are some of the principal benefits which should result from a good DMS installation.

- A DMS should improve the quality of service and customer relations by responding to customer service interruptions more rapidly.
- A DMS should improve the dispatcher's ability to monitor and control the power system during normal, abnormal, and emergency conditions by providing reliable and appropriate real-time data from the network.
- It should improve power system efficiency by helping to maintain acceptable power factors and reducing technical losses
- A DMS should assist power system maintenance and safety practices by providing more reliable, meaningful, and timely records of the operating history of the power system and its field devices.
- A DMS should improve the ability of the engineering staff to perform power systems analysis and planning by providing increased access to past and current operations data and associated software tools.

CHALLENGING ISSUES

In spite of the variety of modern computer-based tools and technologies there are a number of challenges to the implementation and effective operation of DMS systems. The following sections briefly discuss some of these main issues.

Data Capture

The initial capture of the necessary data to fully populate a computer-based DMS is a daunting task. Usually the data exists in a variety of formats, often in different departments, and often data must be combined and merged from different sources, including paper records. This complexity along with the sheer volume of data required for a large distribution utility is a major undertaking.

In many utilities, the data capture process has already been undertaken in the context of the acquisition and implementation of a GIS system. Where a GIS exists, it is obviously desirable to import the data from the GIS. As obvious as this is, nonetheless in the real-world it is not uncommon that the GIS data does not fully satisfy the operational needs. As has already been mentioned, many GIS systems do not have adequate modelling of the electrical connectivity of the network.

DMS Data Change Management

Unfortunately the challenge does not end with a successful one-time capture and population of DMS data. A distribution network is constantly changing, virtually every day as new customers are added, feeders are re-configured, new substations are constructed, older feeders are upgraded to higher voltages, etc. Furthermore, each change has a life-cycle of its own as it goes through planning, design, construction, placing into service and decommissioning of old plant.

It is important to note that generally one network change can affect multiple databases in the DMS. For example, the installation of one new remotely controllable switch on a feeder requires as a minimum, changes to the SCADA points lists. RTU and communications database, the distribution network model and the full graphics displays of the feeder.

It is essential that a modern DMS has full support for management of such network changes. It must have facilities to allow a set of related changes to be defined as a "batch" in an off-line environment and then installed into the on-line environment as a single operation initiated by the dispatcher. The changes must be able to be installed and made effective without interrupting real-time operations, with the possibility of an automatic roll-back if the update is not completely successful in all the databases.

Human Resources. In planning the implementation of a modern DMS a utility must make sure it takes into account the need for dedicated personnel to manage the data and generally maintain the DMS system.

Interfaces between different systems

While some vendors offer a full range of integrated subsystems to make up a complete DMS system, in reality most distribution utilities end up with a variety of different subsystems from different vendors.

Not too long ago many systems were sold as stand-alone packages with not too much thought being given to interfaces with other systems. Integrating such systems was generally very painful and expensive if not totally impossible. However, over the last 10 or so years the need for so called "open" systems has become increasingly evident and important.

Great progress has been made in computer and communication technology to allow computers to communicate with each other. This includes the definition and acceptance of standard SCADA protocols such as DNP and ICCP. Furthermore, the internet has introduced a variety of very common protocols such as HTML, FTP and many others. Thus all modern computers have a basic ability to communicate electronic data with other computers.

However, within specialized areas such as distribution network management there still remains a challenge to determine and define precisely which data in one sub-system is of interest to another sub-system and exactly when, how and under what circumstances data should be exchanged with another system.

Fortunately, this problem is being addressed by the International Electrotechnical Commission, Technical Committee 57, Working Group 13 which has defined an architecture and a data model for distribution networks and operations. It is currently working on defining standard sets of messages and data to be exchanged between subsystems of a distribution management system. Further information on this activity is available on the internet at **http://standards.ces.com/wg14/**. These standards are still in progress, but if and when they get widely accepted they will greatly facilitate such data exchange.

CONCLUSION

There is an increasing need for better and more efficient management of distribution networks. Fortunately, the modern computer industry has come a long way toward providing cost effective technology which can be used to address this need.

While GIS and OMS systems have a role to play, they do not have the full functionality needed on an automated distribution network.

Modern SCADA-based DMS systems have the capability to significantly improve the quality of service to customers as well as making the overall operations more effective and efficient. However, there is still a lot of work which needs to be done to collect, implement and keep up to date all of the data needed for effective distribution management.