DISTRIBUTION MANAGEMENT SYSTEM AT EMPRESAS PUBLICAS DE MEDELLIN [COLOMBIA]

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Abstract

This paper presents the experience of Empresas Públicas de Medellin (EPM) in the implementation of its distribution automation project an integrated SCADA/Distribution Management System (DMS).

It includes some distribution applications, interfaces with existing Geographical Information (GIS) and Customer Information (CIS) Systems to get the information of the distribution networks and the SCADA itself. For the DMS, the main applications are described together with the experience in the implantation of the GIS interface. For SCADA the emphasis of this document is in the experience related with the extensive use of intelligent electronic devices (IEDs) to get the real time information of the distribution feeders, the use of a trunking system for the exchange of information with automated distribution network points and the integration experience of several manufacturers with different communication protocols needed to comply with the project requirements.

The main benefits obtained as well as the risks taken and the main solutions adopted are illustrated for this ambitious project.
The paper will discuss the following points:

- Description of the EPM Distribution system
- Description of the realized project
- DMS Functionality like trouble call system, Crew Management, Outage Management, Switching Procedure Management, Fault Isolation, Fault Isolation and Service Restoration, Distribution system Power Flow, Volt/Var Control, AM/FM/GIS Interface
- Impact to the Quality Indices

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INTRODUCTION

This paper presents the experience of Empresas Públicas de Medellin (EPM) in the implementation of its distribution automation project an integrated SCADA/Distribution Management System (DMS).

It includes some distribution applications, interfaces with existing Geographical Information (GIS) and Customer Information (CIS) Systems to get the information of the distribution networks and the SCADA itself. For the DMS, the main applications are described together with the experience in the implantation of the GIS interface. For SCADA the emphasis of this document is in the experience related with the extensive use of intelligent electronic devices (IEDs) to get the real time information of the distribution feeders, the use of a trunking system for the exchange of information with automated distribution network points and the integration experience of several manufacturers with different communication protocols needed to comply with the project requirements.

The main benefits obtained as well as the risks taken and the main solutions adopted are illustrated for this ambitious project. All project phases are operational and have provided EPM and its users important benefits, and thus have provided for a better corporate image.

EPM, in face of the important changes of the new electric regulation that opened to competition, and given the new technological developments in the supply of electric energy to end customers, decided to start the study, analysis and implementation of a project for automating its distribution energy operation.

The changes for the electric energy distribution utilities, from a technological point of view are numerous. Important to mention are the following:

- The handling of large volumes of information coming from different sources (GIS, CIS, SCADA)
- The technical advance and the increased capacity of computers
- The significant advances in communications
- The adoption of standards related for example with open systems
- The client-server configurations asociated with the new tools for integrating information and
- The use of AM/FM/GIS systems for supporting the operation.

These changes, among others, made it possible to satisfy, with enhanced capabilities, the operational needs of an electric distribution system.

Automation Project Objectives

Improve reliability and electric energy service quality, manage efficiently the substation operation and establish closer and effective relationship with EPM customers to detect and repair the outages with better reaction times are the fundamental objectives of the Distribution Automation Program.
In this form, with the most adequate technology, EPM is looking for competitive advantage in providing improved service and enhance its corporate image that will allow it to face the new demanding conditions of the electricity sector.

EPM DISTRIBUTION SYSTEM DESCRIPTION

EPM distributes electric energy to the city of Medellin, its metropolitan area and other towns in the neighborhood of EPM’s generation plants in an area of approximately 450 square kilometers. EPM has currently approximately 850,000 customers.

EPM’s Distribution Network.

In order to supply electrical energy to the customers, EPM has 220, 110 kV transmission and interconnection lines and 44 and 13.2 kV primary feeders. In addition, it distributes electrical energy through 240/120, 208/120 and 120 volts secondary feeders. Table 1.1 shows the quantity and length of the distribution network and the total number of transformers existent in 1999.

TABLE 1.1. Distribution System Information for 1999

DESCRIPTION	QUANTITY	UNIT
Demand (1999) Energy Sells	1348 6242	MW GWh
44 kV Feeders	54	--
13.2 kV Feeders	393	--
Distribution Transformers	43181	Units
Installed Capacity (Distribution)	2853	MVA

The typical configuration of an EPM substation includes

- 60MVA 110/44/13.2 KV transformers
- 14 feeders at 13.2KV each one, and
- Usually a 44kV feeder output.

Before starting the project the high voltage side of the substations was monitored and controlled from EPM

Transmission and Generation dispatch center (EMS). The distribution part was monitored and controlled manually.

PROJECT DESCRIPTION

In order to develop the project, EPM created in 1994 a group dedicated exclusively to this purpose. The group presented a proposal and a conceptual definition and scope of the project in February 1995.

The Automation Group was integrated with a interdisciplinary group of persons with extensive experience in some of the areas related to the electric energy distribution, as well as with the control and communication areas.

It is to be noted that a different project was already started at EPM dedicated to the various tasks of modeling and gathering data for the geographically referenced data. So the project took as an input all the information available from this separate project.

Selection of the Network to be Automated

For the 13.2 kV level the placement of remote controlled switches was foreseen for initially 26 feeders provided with remote control for sectionalizing the feeder in case of outages. A methodology to determine the order in which the feeders were to be automated was selected. References [5], [6] and [7] provide further details. In addition, radio trunking is employed to communicate with Distribution Terminal Units (DTUs). The radio system operates in the 800 Mhz band.

The communication media used to connect the RTU to the CLD is assured by the use of fiber optic links backed up with telephone circuits. The more remote sites are communicated via fiber optics and Power Line Carrier.

The definition of the switches to be remotely controlled in the project lead to a methodology that has two aspects:

- The classification of the 13.2 kV feeders to be automated by the most predominant type of supplied load.
- The selection of the feeders to be included in the initial automation phase.

For the first aspect, data from billing and from a special program for load survey was used.

For those feeders that were candidate to be automated the analysis started considering those with high loss of revenue due to non-supplied energy. The basic goal is to have a fast return of investment and to increase the quality of service to the customers. With this in mind, industrial, commercial and high income residential areas feeders were picked first.

The following aspects were considered:

- Energy billing cost per feeder (EFAC)
- Non-supplied energy cost per feeder (ENOFAC)
- Feeder Loadability (CACIR)
- Type of load of the feeder (TCAR)
- Service reliability as required by special loads (CONT)
- Type of maintenance (MTO)
- **FES** = equivalent frequency of service curtailment = Number of outages with duration above 3 minute. PU-FES (PU-FES: FES in Per unit)
- **DES** = Equivalent duration of the service curtailment = Sum of the interruption times above 3 minute. (PU-DES: DES in per unit)

Each of the previous factors were weight to determine the Automation Factor (FA), according to the following formulae:

$$FA = 20*(ENOFAC)+20*(EFAC)+10*(CACIR)$$
$$+10*(TCAR)+10*(CONT)+5*(MTO)+$$
$$20*(PU-DES)+5*(PU-DES)$$

The results were then computed calculating those feeders with the highest FAs. As a result 26 Feeders were selected which were equipped with 3 switches each for a total of 78 switches. In the implementation phase the actual sites of the switches were reevaluated and thus finally optimal sites were selected for 42 feeders.

Acquisition Strategies

The goal was to purchase a Distribution Management System (DMS) constructed around a kernel with the Distribution System Operation Model (DSOM) that would allow to have a common user interface and that conceptually could interface with other systems [2],[3],[4] (see figure 1).

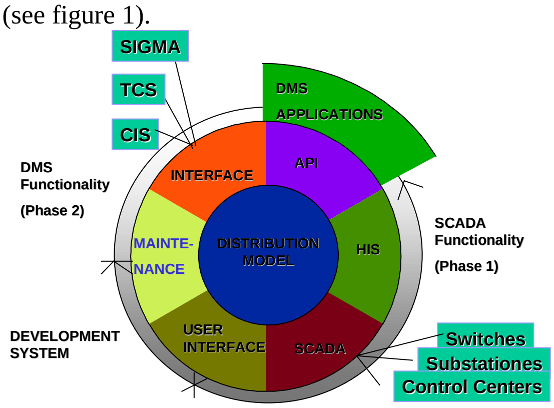

Figure 1

The distribution system operation model allows the visualization of the actual state or topology of the distribution system, supported by a relational data base.

- One of the important strategies for fulfilling the project goals on a short term was the definition of phases for the project development, each one providing its own functionality, tested and commissioned to satisfaction. This allowed getting project benefits without having to wait until the full implementation.

ACQUISITION STRATEGY

The control center functionality was split into two phases: one corresponding to SCADA to be implemented in 18 months (starting from contract signature) and the second phase dedicated to implement the DMS applications in 36 months from contract start). The only requirement in this approach is to have enough people available to be trained during the second phase of the project because the operation requires the commitment of personnel to the first phase put in service.

To make the process more competitive, one should avoid the dependence on only one supplier and allow firms that only had equipment and software for specific portions of the entire supply. Therefore an international bid process with three groups was started:

- Group 1 with a central functionality, software and computer equipment
- Group 2 including all field equipment, switches and RTUs
- Group 3, which was issued as an optional one for EPM, with the proteccion, measurement and integrated control units (IEDs) for collection of data from the 13.2 and 44 kV feeders

Once found that the solution based on IEDs represented only a small cost as compared to a conventional solution using transducers and with the additional benefit of modernizing all the feeder protection schemes, also the equipment related with group 3 was purchased by EPM.

DMS FUNCTIONALITY

The distribution applications are built around a distribution system operation model that integrates all the functionality and allows to have a common user interface and cover a wide range of modules that support the main operational activities like:

- The User Interface function that consists of facilities for dispatcher/operators to communicate with the distribution system through the operating consoles.
- Trouble Call System that assists the operator in answering and recording customer telephone calls that indicate loss of supply and other problems in the field. The TCS analyzes the problem and attempts to identify the reason of the outage based in the actual network topology and number of calls.
- Crew Management that provides convenient access to the information necessary to track, contact, and assign work schedules to the utility field crews. The operator is informed about the actual position of the crews through a GPS interface that is updated in a regular base into the DMS system.

- Outage Management System is a collection of functions, tools and procedures that a dispatcher uses to manage the detection, location, isolation, correction, and restoration of faults that occur unexpectedly on the electric network. OMS is also used to facilitate the preparation and resolution of planned outages.

- Switching Procedure Management that allow the operator to create, select, edit, execute, print, and store network control procedures consisting of supervisory control requests on-line (real-time) or in simulation (study) mode.

- Fault Location that determine the smallest possible faulted section based on available real-time data from the SCADA and other information such as that from Trouble call System.

- Fault Isolation and Service Restoration that determines switching actions that allow the operator to isolate areas of the network and to restore service to customers in a manner that will minimize the effect of the outage. The needed switching procedures are generated automatically by this application.

- The Distribution System Power Flow that is used to study electric power distribution networks under different loading conditions and configurations. The DSPF could be run as in real-time as in study mode. In real-time executes periodically and upon any change in the distribution network as well as on operator’s demand, such that it reflects the actual state of the distribution network. In study mode, it could be used to model “what if” scenarios.

- The Volt/Var Control function that provides the possibility to control transformer tap position changers (LTC, voltage regulators) and switchable shunt reactive devices (typically capacitors) directly or through existing local automatic controllers. Co-gens, NUGs and IPPS are modeled, but are not used as control resources in the optimization. The VVC function objectives are to minimize power demand, or to maximize generated reactive power, or to maximize revenue satisfying voltage and loading constraints.
- The AM/FM/GIS Interface to convert “maps” and data that have been created in an AM/FM/GIS environment into the operational database structures that support the other distribution functions. The appearance of the information in the DMS system is the same as in the AM/FM/GIS environment.

Among the functionality described the AM/GIS Interface is the most critical application in the system because it is the only way to supply all the distribution information to the model. In fact, there is no simple way to manipulate information piece by piece like in an EMS system given its characteristic and also its volume. So the importation process must be highly automated to avoid manual intervention as much as possible, implementing at the same time the means to identify errors and checking mechanisms to allow a practical interface. An additional problem that is normally encountered in this type of interface is related to performance issues that in the case of EPM project was taken care of by proper hardware and software architecture

DMS combines real data coming from the substations and some feeders with this powerful applications in an integrate system to help EPM to operate its distribution network.

PROJECT IMPLEMENTATION

The implementation process of such a huge system has not been an easy task. The main difficulties in putting in service the system have been in the importing process. The GIS and DMS projects were running in parallel in EPM and because of some difficulties in the data conversion process in the GIS do not let to EPM to have enough information to test all the DMS functionality including the GIS Interface itself in the site acceptance test.
From the point of view of the SCADA all the 34 substation were putting into the system in two years without major problems.

To avoid risk in the development of these kind of projects utilities must avoid delays in the data delivery to the supplier of the functionality. The interface, the applications and the right sizing of the database of the system must be carefully tested in factory and at site.

The GIS interface must have a friendly appearance, the operator, using buttons in a window, must control all the actions since the extracting process from the GIS until the information could be put in the DMS side. The interface must provide pop up windows with additional information about errors, importation process status and so on.

Additionally the system must have the capability to define several layers and distribute all the electric and geographical information in those layers. A special emphasis should be put in the error detection modules to avoid data inconsistencies into the system.

The distribution system is changing every day so it is necessary that the GIS interface could have the ability to incorporate those changes in an incremental way.

GENERAL SYSTEM CONFIGURATION

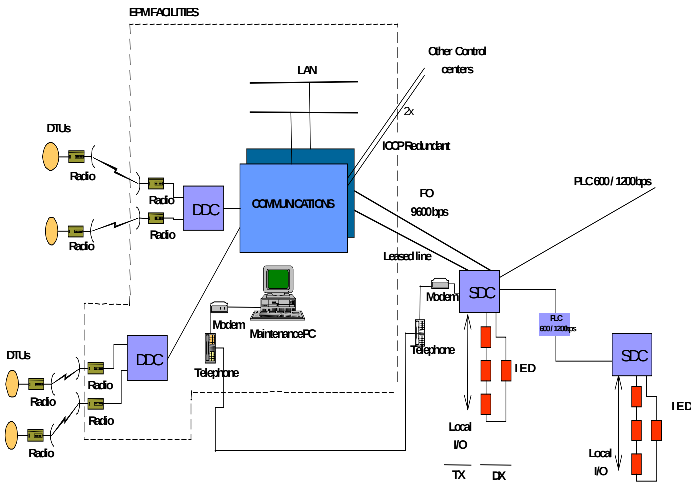

Figure 2

Figure 2 presents a general control system equipment overview starting with the “front-end” computers and showing mainly the substation and field equipment.

IMPACT OF THE PROYECT ON QUALITY INDEXES

Starting from the moment of the IED installation, which provided for recording the fault currents, a statistical analysis was initiated with the information collected during a 6 months period, for 10 substations where this equipment was available. The goal was to evaluate the protection scheme that was implemented and to study potential improvements. Based on 1300 records of fault currents, it was determined that 65% of the faults had short circuit levels that were above the established threshold of 2400 A.

In consequence the following adjustments were made:

- The instant trip function of the relay was adjusted to 6000A with blocked reclosing.
- For circuits with reclosers, the reclosing action was set for currents between 520 and 6000A with a delay of 110 msec at the relay for sending the signal to the breaker. This delay normally is enough to allow the fault to be cleared by the recloser action in its first operation. In feeders without recloser the relay delay time is set to 40 msec.
- Activate the zone of relay coordination in order to avoid reclosing actions when the fault is being cleared by a “down-stream” device.
- Adjust the reclosers to its fastest characteristic curve for the initial trips.
- Adjust the reclosers for the delayed operations to the extreme inverse curve (as much as possible). In addition, adjust the dead-times of the reclosers to times above 1 sec. For their operation on the fastest curves.

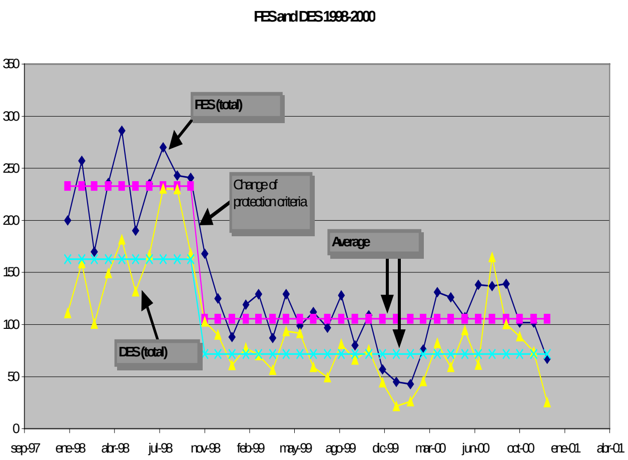

Figure 3

These actions have had extremely good results as shown in figure 3; starting from the date of their implementation a significant improvement on the quality of service indexes (FES and DES) have been recorded.

It is to be noted that in the four years prior to the project implementation, EPM was executing several tasks dedicated to reduce the faults and their duration for the distribution network. The following changes were made: change of the bar cables to isolated ones, maintenance with focus on the fault areas, frequent and enhanced tree trimming, etc. without consistent results. The slight fault reduction for certain periods were not stable normally due to the change of summer to winter and storm conditions. In essence the improvements to the indexes were never as good as those reached with the results shown above.

CONCLUSIONS

This project, originally defined in 1995 is operational and has provided EPM considerable benefits derived directly from the technical solutions implemented. Part of these benefits, are given by the remote operation of all substations equipped with the new IEDs, remote terminal units and data concentrators. The benefits are a direct consequence of the better information collected for decision making, planning and operation, which has to improved reaction times to emergencies and improved coordination among the various divisions of EPM involved.

The development of the project phases showed that it is feasible to implement a complex project on time and within budget, which includes the supply of various manufacturers and multiple protocol solutions. The system and technology now available to EPM is able to accommodate new equipment and future functions. The phased implementation allowed to decompose in time the various tasks and the optimal use of the human resources of the utility.

The functionality implemented has responded well to expectations. As explained the most critical one is the AM/GIS interface. Due to its characteristics, it is vital for this type of system to have ready data as early as possible in the project. Other functionality such as trouble call start to provide benefits immediately and also approaches the utility to the end-customer thus improving the utilities' image, one of the goals of EPM for this project.

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