Distribution Substation Monitoring System

Geraldo Rocha, David Dolezilek, Fernando Ayello, and Carlos Oliveira
Schweitzer Engineering Laboratories, Inc.

Published in the
proceedings of the 2nd Annual Protection, Automation and Control World Conference
Dublin, Ireland
June 27–30, 2011

Distribution Substation Monitoring System

Geraldo Rocha, David Dolezilek, Fernando Ayello, and Carlos Oliveira, *Schweitzer Engineering Laboratories, Inc.*

***Abstract*—With the competitiveness of the electrical energy market, the prevention of faults and defects in substation primary equipment is considered a major differentiating factor in the quality of power delivered by utilities. The reduction of faults and defects that cause interruptions in the supply of electrical energy significantly improves service performance rates. To achieve this objective, more efficient and intelligent maintenance practices are required and material, human, and financial resources must be invested correctly. The rules and requirements of the modern market no longer permit numerous corrective maintenance procedures or periodic maintenance practices. Recent cost-effective improvements in performance and power supply quality indexes have been demonstrated by utilities that have migrated from periodic and intensive corrective maintenance practices to predictive maintenance identified by substation equipment monitoring systems.**

The substation equipment monitoring system described in this paper meets the requirements of maintenance engineering teams by monitoring substation equipment, such as power transformers, circuit breakers, dc battery systems, and disconnect switches. Collection of this information is a convenient byproduct of the digitalization of communications messages among protection, control, and monitoring intelligent electronic devices (IEDs) in distribution substations for real-time automation and protection applications. Reuse of data within these IEDs for the purpose of equipment monitoring minimizes the need for new devices, such as special-purpose meters and sensors. Using protection, control, and monitoring IEDs as the source of information to understand the health and performance of substation apparatus makes the implementation of a monitoring system economical and technically attractive.

I. Introduction

The prevention of problems in the electrical power supply system, as well as the adoption of modern maintenance practices, is vital for electrical sector companies in their search for continuous improvement of performance and power supply quality indexes.

Large companies are free to choose their electrical energy supplier and frequently use the demand profile and voltage level at the delivery point to negotiate prices. Also, new regulations permit customers to request reimbursement for energy interruptions, so the electric energy utilities have new financial drivers to provide a high-quality power supply.

With these new measures, specific service indexes for each installation are monitored separately, which means that even small distribution substations need to be monitored because they may contribute to the accrual of fines against the distribution company.

All of these requirements have forced power distribution companies to review maintenance concepts and strategies for their equipment and increasingly seek out actions that will allow them to reduce corrective and preventive maintenance by intensifying the practice of predictive maintenance.

However, to enable an assertive migration to predictive maintenance, direct and constant monitoring of equipment is necessary to predict failures and optimize equipment maintenance.

Only with the analysis of information collected in real time from the equipment is it possible to establish maintenance based on real conditions and not on time intervals. This analysis makes it possible to extend the maintenance cycle and minimize related costs.

Standalone equipment monitoring systems are often specified and acquired by electric energy distribution companies to provide information for predictive maintenance planning. When designed carefully and installed with sufficient monitoring sensors, these systems provide consistent data for the correct analysis and scheduling of equipment maintenance.

However, due to the high cost of the equipment installation, communications network, and purchase and maintenance fees for the software infrastructure for data storage, this type of system is not viable for small- and medium-sized distribution substations.

The system presented in this paper uses data supplied by intelligent electronic devices (IEDs) and takes advantage of the communications network structure already in place as part of the substation automation system (SAS) that is performing protection, control, and monitoring (PCM). These PCM IEDs constantly calculate equipment health and performance as a byproduct of performing protection and control of the apparatus. This information is constantly and correctly calculated into analytics within the IEDs, based on algorithms created by power apparatus experts. The function of the substation monitoring system (SMS) is to monitor the power transformers, medium- and high-voltage circuit breakers, reclosers, dc battery systems, and disconnect switches of a substation, minimizing the need for new devices, such as special-purpose meters and sensors, and composing an economical and technically attractive solution.

II. Conventional Monitoring Systems

A standalone equipment monitoring system centrally calculates information from numerous pieces of data received from sensors installed in the field to verify the actual conditions of the equipment and predict the need for maintenance using preprogrammed analysis.

The basic structure of this system is illustrated in Fig. 1.

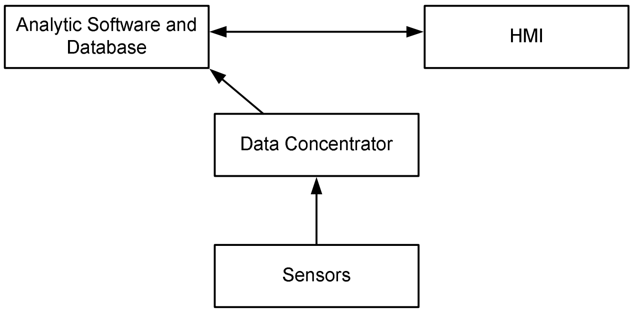

Fig. 1. Conventional monitoring system

Sensors collect the quantities in the field, process the signals, and send them to a data concentrator unit.

Normally, the sensors installed are potential transformers (PTs), current transformers (CTs), resistance temperature devices (RTDs), moisture sensors, position sensors, signal transducers, and so on.

In order to concentrate the data into a single location within the substation, data collectors such as remote terminal units (RTUs), programmable logic controllers, industrial computers, data acquisition modules, and other devices are used.

After collection and concentration, the data are sent to a relational database. Analytic software uses algorithms that process the received data, define the actual situation of the monitored equipment, and estimate a time interval until the next maintenance action.

The human-machine interface (HMI) allows the user to visualize the treated and stored data using the analytic software.

However, conventional monitoring systems require installation of new, specialized equipment and sensors and a specific communications network for this data traffic. Also, they fail to take advantage of the existing SAS communications network and the equipment monitoring information already being calculated within the PCM IEDs.

III. Power Distribution Substations

The supervision, protection, and control functions within an electric power SAS are developed to meet the operational requirements of the electrical system. An SAS is composed of protective relays, controllers, communications networks, and one or more gateways to facilitate integration with remote supervisory control and data acquisition (SCADA), remote synchrophasor and disturbance recording, local and remote engineering workstations, and a local HMI. The purpose of the engineering workstation is to facilitate the activities performed by operators and/or automation applications locally or remotely, such as switching, monitoring real-time readings, archiving and viewing historical records, and viewing and recording lists of events and alarms. The engineering workstation also makes it easier for the engineering team to access data for changing protection settings and collect oscillographic data [1].

To provide engineers with access to these data, complementary software is used. The software may be operated on a local or remote computer. The system operators collect real-time information as they require it remotely and locally via HMI, locally via IEDs, and locally from the equipment. The information is accessed offline by the engineering teams via remote computer connections. In the event of a communications failure, there is local access through each IED. The supervision, protection, and control systems traditionally use SCADA messages to meet the requirements of operation and engineering and not to collect equipment monitoring information within the PCM IEDs.

The IEC 61850 standard establishes the functionalities of the vertical and horizontal communications protocols, enabling interoperability between the systems and quick exchange of multiple types of messages between the equipment of the protection, control, supervision, and measurement systems of the substations (in other words, the IEDs).

Power distribution substations designed to use the functionalities of IEC 61850 protocols can be optimized by using messages designed for SCADA, real-time data exchange, and collection of equipment monitoring information, significantly reducing equipment used for protection, control, measurement, and automation.

The communications network architecture of a distribution substation based on IEC 61850 is shown in Fig. 2.

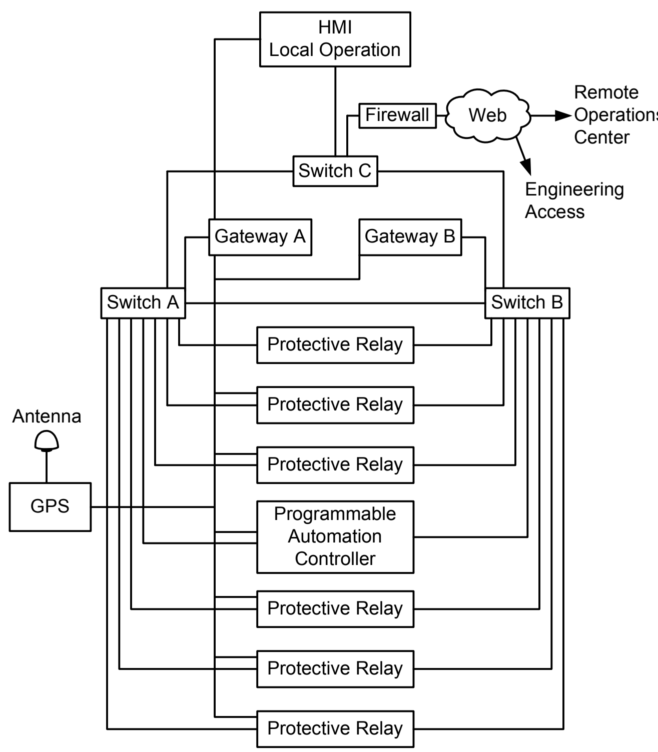

Fig. 2. Data communications network

An internal communications network for an efficient substation is designed to allow redundant communications channels, which means that if a communications cable or an Ethernet switch fails, communications can be transferred to another Ethernet interface without degrading the system. Communications with the control center and with the HMI are normally conducted using a gateway to concentrate and collect the data from the IEDs via IEC 61850 and then convert them into protocols such as DNP3 LAN/WAN.

IV. IED Monitoring Functions

The IEDs used in the digitalization of distribution substations include protection, automation, control, and communications functionalities. They also collect and create important analytical data by monitoring the devices and the surroundings that the IEDs protect.

As such, each main device of a substation has at least one associated IED receiving voltage, current, status, and other signals that are used to make precise diagnoses in real time. Because IEDs are connected to the dc system of a substation, they also provide important information for the monitoring and diagnosis of the substation dc battery system [2] [3].

In this way, the information available in an IED is used to monitor circuit breakers, disconnect switches, power transformers, and dc battery systems.

In the following sections, we analyze the monitoring data available for each piece of equipment from the IEDs used in the digitalization of the substations.

A. Circuit Breakers

The maintenance of circuit breakers is usually based on regular time intervals or the number of operations performed. The methods based on this philosophy present drawbacks because within the predetermined maintenance interval, there could be an abnormal number of operations or a small number of operations with high-level currents.

The IEDs monitor the following:

- Contact wear. The circuit breaker manufacturer provides a maintenance curve listing the number of close-to-open operations and the interruption current levels. The function of this curve is to predict the breaker contact wear, as the example shows in Fig. 3. It is possible to configure some of the points of this curve, where normally the highest and lowest number of operations and an average point are chosen. For each operation, the IED integrates the interrupted current with the operation number to update the contact wear value. This parameter is crucial to estimate the need for maintenance.
- Total number of operations. Incremental counters for close-to-open operations are implemented to make that information available to the system history.
- Mechanical operating time. The mechanical operating time of the circuit breaker can be calculated by measuring the time interval between the trip command or the close command and the asserting of the digital inputs of the IED connected to the circuit breaker status contacts. Deviations in this value may indicate problems in the drive mechanism.
- Electrical operating time. Similar to the mechanical operating time, this measures the time interval between the trip or the close command and the clearing or normalization of current measurements in the circuit breaker. If this parameter tends to increase over time, it could indicate failures in the contacts.
- Inactivity time. By monitoring the activity of the number of operations, it is possible to calculate the number of days in which the breaker has been inactive. Long periods of inactivity degrade its reliability for the protection system.
- Spring-loading time. Just after the circuit breaker closes, the time to assert the digital inputs of the IED connected to the breaker loaded spring contact is measured. If this time increases as the number of operations increases, it may predict a problem in the spring-loading mechanism.

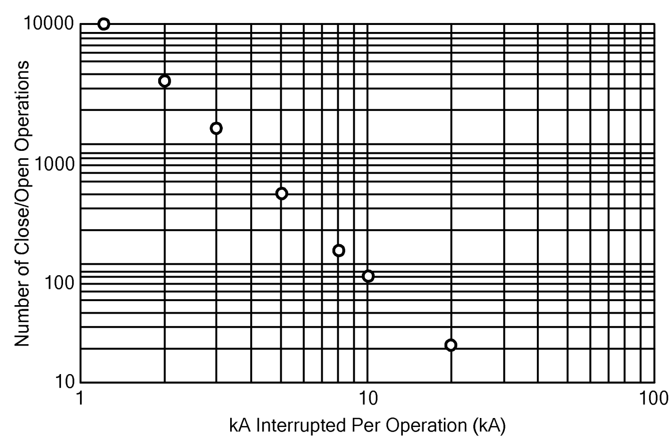

Fig. 3. Circuit breaker maintenance curve

The monitoring functions presented here are performed in a PCM IED with traditional protection PTs and CTs. No additional standalone sensor is necessary for the equipment monitoring system, as shown in the basic connection diagram in Fig. 4.

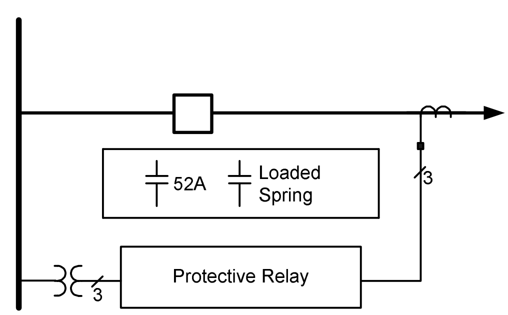

Fig. 4. Basic connection diagram for monitoring of circuit breakers

An example of the knowledge of the health and performance of a breaker, calculated by a PCM IED and documented as a breaker monitoring report retrieved from that IED, is shown in Fig. 5.

```
=>>BRE S <Enter>
Relay 1                                              Date: 04/07/2008 Time: 23:31:48.184
Station A                                            Serial Number: 2008030645

Breaker S

Breaker S Report
                              Trip A   Trip B   Trip C   Cls A   Cls B   Cls  C
Avg Elect Op Time (ms)          50.0    48.0     48.0     60.0    58.3    58.7
Last Elect Op Time (ms)         56.2    58.4     58.4     66.9    68.2    68.7

                               Trip     Cls
Avg Mech Op Time (ms)           52.2    66.4
Last Mech Op Time (ms)          61.2    68.2

Last Op Minimum DC1 (V)         115.8
Inactivity Time (days)          5       2

                              Pole A  Pole B  Pole C
Accum Pri Current (kA)         5.997 13.9898 7.99588
Accum Contact Wear (%)           0.5     0.5     0.5
Max Interrupted Current (%)      3.0     13.0    5.0
Last Interrupted Current(%)      3.0     13.0    5.0

Number of Operations               5

                              Alarm   Total Count
Mechanical Operating Time     MSOAL       0
Electrical Operating Time     ESOAL       4
Breaker Inactivity Time       BITAL       0
Current (kA) Interrupted      KAIAL       0

LAST BREAKER MONITOR RESET    04/07/2008 20:10:07.121
=>>
```

Fig. 5. Breaker monitoring report

B. DC Battery Systems

The dc auxiliary service of a substation is responsible for supplying dc current for all devices. It is composed basically of a rectifier, a battery charger, and a bank of batteries for each level of dc voltage required.

The proper operation of the dc battery system and the source of ac is essential for the operation of the control and protection systems of a substation. However, not all the rectifiers and battery chargers have autodiagnostic mechanisms, and those that have them only signal to indicate alarm situations. Traditionally, the efficient diagnosis of the health of the dc system of a substation can only be made by adding specific equipment for this function. However, these data also exist in PCM IEDs. These IEDs have the capacity to monitor the dc system with precision and monitor the following:

- DC voltage and/or positive and negative poles. A difference between the measurements of the poles may indicate a leakage current to ground and possible damage to the charger and/or rectifier.
- DC voltage level. A high or low level of dc voltage can damage the dc battery system or not maintain a proper charging.
- Detection of leakage current to ground. If the installation of the dc battery system has a central grounding, it is possible to measure the leakage current to ground and predict problems in the bank battery cabling.
- AC ripple in the rectifier. High levels of the ac component of voltage delivered by the rectifier can irreversibly damage the batteries.

Additional sensors are not required for this type of monitoring, as shown in the basic connection diagram in Fig. 6.

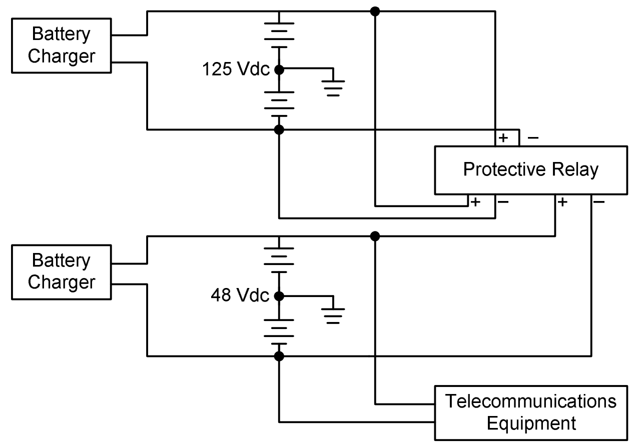

Fig. 6. Basic connection diagram for monitoring of two dc battery systems

An example of the knowledge of the health and performance of the dc power supply, calculated by a PCM IED and documented as a dc power system monitoring report retrieved from that IED, is shown in Fig. 7.

```
=>MET BAT <Enter>
Relay 1                                           Date: 03/22/2001 Time: 09:37:10.035
Station A                                         Serial Number: 2001001234

Station Battery       VDC      VDCPO      VDCNE      VAC
   VDC1 (V)           24.17     11.98     -12.19      0.01
   VDC2 (V)           47.68     23.80     -23.88      0.02

             VDC1(V)     Date        Time          VDC2(V)    Date       Time
Minimum        20.12  03/15/2001  14:28:59.172      41.64 03/22/2001 08:46:25.726
Enter L-Zone          03/15/2001  14:28:51.490            03/18/2001 18:46:23.868
Exit L-Zone           03/15/2001  14:29:05.035            03/18/2001 18:47:55.441

Maximum        27.19  03/19/2001  08:34:49.761      50.84 03/22/2001 08:34:55.490
Enter H-Zone          03/19/2001  08:34:27.172            03/22/2001 08:34:27.172
Exit H-Zone           03/19/2001  08:37:01.041            03/22/2001 08:35:00.912

LAST DC RESET:    03/15/2001 12:30:30.492
=>
```

Fig. 7. DC battery system monitoring report

C. Power Transformers

The power transformer is the most important equipment in a distribution substation. The high cost of procurement, transportation, and installation, along with long lead times, can make transformer replacement a difficult and time-consuming task. Therefore, monitoring is essential for providing efficient maintenance as well as for the optimal use of operational capacities.

There is a range of monitoring sensors and systems designed especially for substation power transformers and IEDs that have thermal modeling in accordance with IEEE C57.91-1995, IEEE Guide for Loading Mineral-Oil-Immersed Transformers.

Again, instead of standalone monitoring equipment, PCM IEDs use the data obtained from PTs and CTs in combination with temperature sensors to calculate the top-oil temperature and the winding hot-spot temperature.

The IEDs also monitor the following:

- Measured ambient temperature.
- Measured and calculated top-oil temperatures.

- Measured and calculated winding hot-spot temperatures.
- Daily loss-of-life rate.
- Accumulated loss-of-life rate.
- Efficiency of the forced ventilation system.
- Insulation aging acceleration factor.
- Estimated insulation life service.
- Detection of electrical and mechanical stresses caused by through faults.

For monitoring the power transformer, the connection of temperature signals to the PCM IED allows correct calculation of thermal modeling, as shown in Fig. 8.

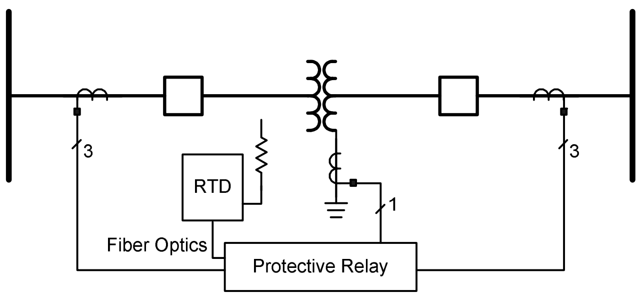

Fig. 8. Basic connection diagram for monitoring of transformers

An example of the knowledge of the health and performance of the transformer, calculated by a PCM IED and documented as a transformer monitoring report retrieved from that IED, is shown in Fig. 9.

```
=>>THE <Enter>

Relay 1                                        Date: 03/28/2008 Time: 02:12:44.594
Station A                                      Serial Number: 2008030645

                                 Transformer 1 Transformer 2 Transformer 3
     Thermal Element Condition :  NORMAL       NORMAL       NORMAL
                Load(Per Unit) : 0.81         0.83         0.81
      In Service Cooling Stage : 1            1            1
              Ambient (deg. C) : 20.0         20.0         20.0
   Calculated Top Oil (deg. C) : 25.4         26.1         25.7
     Measured Top Oil (deg. C) : 46.6         46.9         46.1
     Winding Hot Spot (deg. C) : 55.4         56.8         55.1
Aging Acceleration Factor, FAA : 0.00         0.00         0.00
           Rate of LOL (%/day) : 0.00         0.00         0.00
     Total Accumulated LOL (%) : 0.00         0.00         0.00
          Time-Assert TLL (hrs) : 0.00         0.00         0.00
=>>
```

Fig. 9. Transformer monitoring report

Along with thermal monitoring capabilities, the PCM IEDs also have the capability to monitor accumulated through-fault energy experienced by the transformer over its lifetime. IEEE C57.109-1993, IEEE Guide for Liquid-Immersed Transformers Through-Fault-Current Duration, describes thermal and mechanical damage limits based on through-fault current experienced by the transformer. Through-fault current is the current that passes through the windings of the transformer during external fault conditions. The magnitude and duration of this through-fault current have an impact on the transformer. Through-fault energy with low magnitude and duration will typically cause some thermal stress to the insulation system of the transformer. Larger magnitude and duration can lead to the physical displacement of the windings during the through-fault event, which can lead to insulation system degradation.

The differential current protection provided by the IEDs can also be used to measure and log the amount of through-fault energy experienced by the transformer. Limits can be set to indicate when specific levels of accumulated through-fault energy have been exceeded. Excessive accumulated through-fault energy indications can then be used to efficiently drive additional maintenance procedures, such as dissolved gas analysis, on the transformer.

An example of a PCM IED through-fault monitoring report is shown in Fig. 10.

```
=>>TFE <Enter>
                                                  Date: 01/29/2008   Time: 16:53:59
Winding 1

Total Number of Transformer Through Faults: 2
Total Number of A Phase Through Faults:     2
Total Number of B Phase Through Faults:     1
Total Number of C Phase Through Faults:     0

Total Accumulated Percentage of Through Fault Capability:
                     A-Phase    B-Phase    C-Phase
                     41.69      4.55       0.00

Through Fault Alarm: 0          0          0

Last Reset: 01/29/2008 16:48:39
#  DATE       TIME          Duration  IA     IB     IC     A      B      C    Alarm
                            (seconds) (max primary kA)     (Increment %)
0  01/29/2008 16:53:26.029  1.000     3.19  3 .25  0.00   4.60   4.55   0.00
1  01/29/2008 16:49:39.548  18.096    2.13  0.00   0.00   37.09  0.00   0.00
```

Fig. 10. Through-fault monitoring report

In addition to thermal and mechanical stress aspects, measurements for humidity and gases dissolved in the oil and the power factor of high-voltage bushings can be incorporated into the system through the application of specialized IEDs. These data are added to the system via digitized messages between the gateway and the specialized IED.

Using a correlation of thermal and moisture measurements, it is possible to predict the formation of bubbles that can cause a serious accident, as well as guide the operation of the transformer with regard to the use of an optimized and safe maximum load in real time.

D. Disconnect Switches

Disconnect switches are located in the substation, used for network reconfiguration, and normally follow the same maintenance philosophy as circuit breakers (i.e., based on the number of operations and fixed time intervals). As explained previously, this philosophy is not always the most efficient one.

The monitoring of this equipment is based principally on the electromechanical aspects, which require specialized sensors for measuring angular positioning.

Appropriate programmable automation controllers (PACs) are used to measure the active and reactive power of the motors during operation and receive signals from the angular positioning sensors and the status of the auxiliary contacts of the disconnect switches. These PACs become PCM IEDs and must satisfy the same requirements for reliability as protective relays. They must also meet the same requirements for high availability, environmental ruggedness, and multiple protocols documented in the IEC 61850 communications standard. In this scenario, the PACs are used to monitor the following:

- Number of operations. Incremental counters for close-to-open operations are implemented in the controllers to make that information available to the system history.
- Inactivity time. By monitoring the variation in the number of operations, it is possible for the PAC to calculate the number of days in which the disconnect switch has been inactive. Long periods of inactivity reduce the reliability of the operation.
- Switching time for opening and closing. By measuring the time interval between the open or close command and the asserting of the digital inputs of the PAC connected to the disconnect switch status contacts, it is possible to calculate the time of the operation of the switch. Deviations in this value may indicate problems in the drive mechanism.
- Average and maximum motor power during operation. The motor power is measured by the PAC through transducers. These samples can be used to calculate the average and maximum values. When these two parameters trend upward, it may indicate mechanical problems in the structure or a failure in the motor.
- Angular position. The PAC provides this information for evaluation using angular positioning sensors. If the angle recorded exceeds the nominal position, it is indicative of an overload of the mechanical structure and motor. On the other hand, if the angle is smaller, this may indicate a failure in the operation.

Fig. 11 is a basic connection diagram for the monitoring functions presented above.

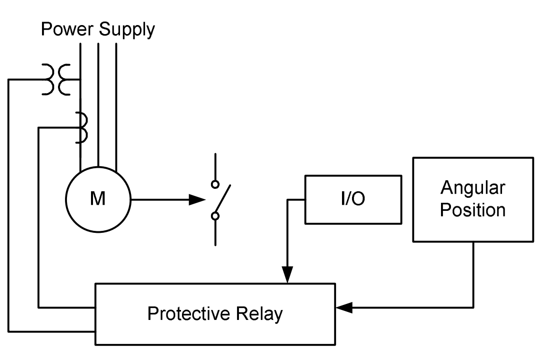

Fig. 11. Basic connection diagram for monitoring of disconnect switches

V. Premises for the Development of the Distribution Substation Monitoring System

As shown previously, investments in substation monitoring systems are essential for creating reliable predictive maintenance; however, standalone systems are complicated and expensive and are only viable for large substations, even though they are becoming essential for smaller distribution substations [4].

Now that we understand the structure of the existing SAS network in a substation and the functionalities of monitoring present in PCM IEDs, it is clear that an economically viable monitoring system can be developed by using the network structure and data provided while maintaining the same reliability, regardless of the size of the facility.

Therefore, the requirements for implementation of an SMS that leverages the monitoring capabilities of the SAS are defined as follows:

- Development of a monitoring system dedicated to managing the maintenance functionally separate from the real-time operation system.
- Use of PCM IEDs with monitoring functions as a source of data.
- Use of the communications network infrastructure already in place or provided for the substation as a result of SAS digitalization.
- Low investment cost, making installation viable in any substation.
- High reliability and availability of data.

The software requirements for SMS implementation are as follows:

- Integration with an Ethernet network.
- Remote access to the web via intranet or Internet without the need for additional software and independent of an operational system.
- Use of a unified database.
- Graphical analysis with trend lines.
- Availability of historical data, analysis, and alarms.
- Values recorded for emission of anomaly alerts or alarms for each variable.
- Alarms sent through email, voicemail, or text messaging to cell phones.
- User registration with passwords and hierarchal level access.

VI. Development of the SMS

A. Functional Software Modules

With the scenario and requirements well defined, the SMS was developed using the following basic structure presented in Fig. 12, created in the local maintenance server:

- Data concentrator. This is the functional module responsible for collecting information from the IEDs using Transmission Control Protocol/Internet Protocol (TCP/IP) or serial communications. It uses the major market protocols such as DNP3, Modbus®, IEC 60870, IEC 61850, and OPC.

- SMS manager. This is responsible for managing all of the functional modules of the system. Using distributed computing concepts, this ensures total modularity with a view to expanding the system.
- Database. This centralizes information from the entire system. In order to reduce costs, use database solutions that show excellent performance and are exempt from licensing. Large facilities can use more robust SQL servers.
- SMS publisher: This module is responsible for publishing the system information contained in the database through the web interface. It uses multilayered architecture with Advanced Message Queuing Protocol (AMQP) interfaces and protocol buffers widely used in online web applications.
- SMS engine: This module is the brain of the entire monitoring system and it is responsible for the entire intelligence of the monitoring routines. Basically, it collects information from the database, processes it, and places the results again into the database using the SMS manager, which publishes them indirectly on the screens of the SMS publisher. This module is also responsible for carrying out the automatic analyses and generating alarms.

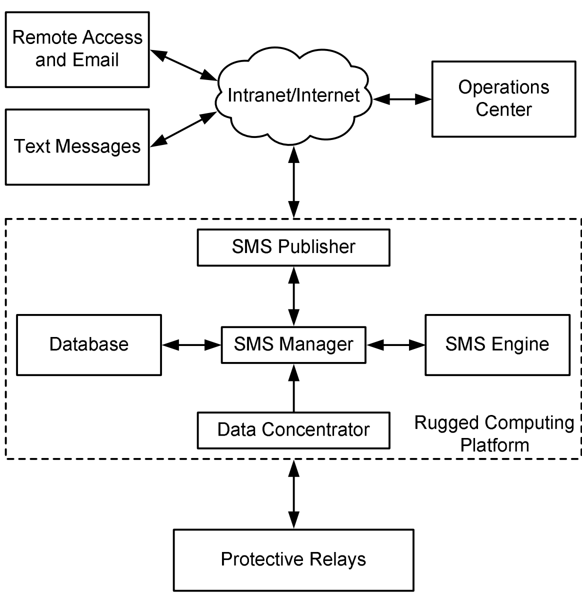

Fig. 12. Basic data structure of SMS

B. Automatic Analysis of SMS Engine

In addition to providing the user with tools for the analysis of the equipment monitoring data, the SMS also carries out preprogrammed automatic analysis.

For each new value of monitored variables, the SMS engine uses stochastic methods to predict the value after a number of future programmed days. If this value exceeds programmed levels, a notification is generated. The notification can be an alarm or an anomaly alert, where the first alert is for an abnormal operation scenario and the second is indicative of a failure that impedes the functioning of the equipment.

In order to control the generation of an excessive number of notifications, the SMS has the option to generate only one of each type of notification per 24-hour interval. That is, once an alarm is generated for a given variable, only after 24 hours can another be generated. However, if the alarm progresses to an anomaly alert, this will be generated even if the interval between the alerts is shorter.

C. Local Maintenance Server

The local maintenance server used is based on a robust computing platform, which meets the IEEE 1613 standard, does not have moving parts, and has a high mean time between failures (MTBF) when compared with conventional computing platforms.

In keeping with the premise of using the same communications network existing in the substation, the computing platform has EIA-232 serial ports and Ethernet ports.

A variety of communications ports and protocols allows a broad application of hardware and easy integration with any communications system existing in the substation. Fig. 13 shows the local maintenance server containing the integrated SMS without any change in the communications network presented previously in Fig. 2.

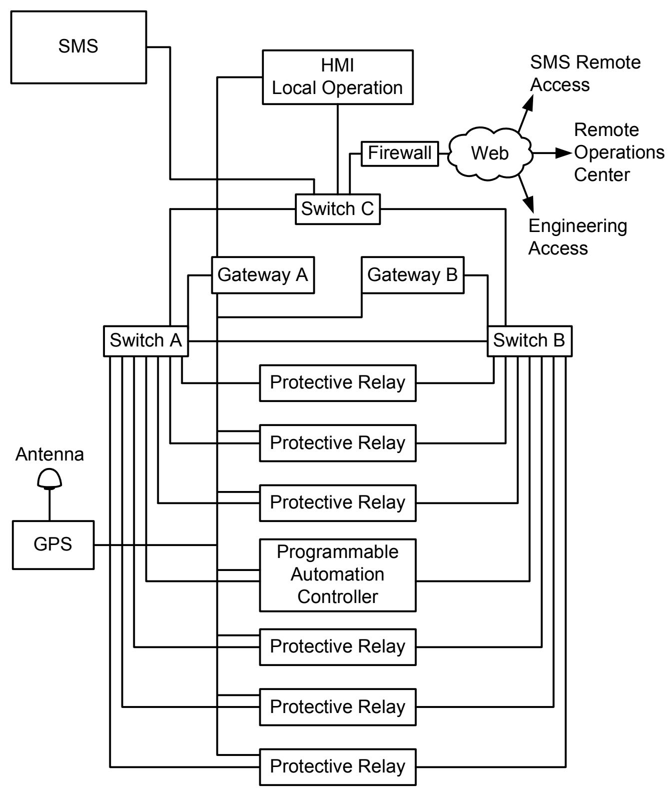

Fig. 13. Example of SMS integrated in the substation

The engineers and those responsible for the maintenance of this equipment access the information locally on the SMS manager or remotely through the web via intranet or Internet. Considering the access through the maintenance center, the installation of additional software is not necessary because the SMS was created independently of the operational system. The SMS uses Ethernet network communications and is in compliance with the IEC 61850 standard. Even so, it adapts to substations that are not in compliance with the standard because of the flexibility and multiprotocol structure existing in the system.

VII. Simulation and Test Rack

In order to test the SMS, a simple replica of a supervision, control, and protection system for a typical substation was created in an automation and protection laboratory. Some circuit breakers, disconnect switches, sensors, and other equipment were simulated to reproduce the normal operating conditions of a substation. The one-line diagram of the hypothetical substation used is shown in Fig. 14.

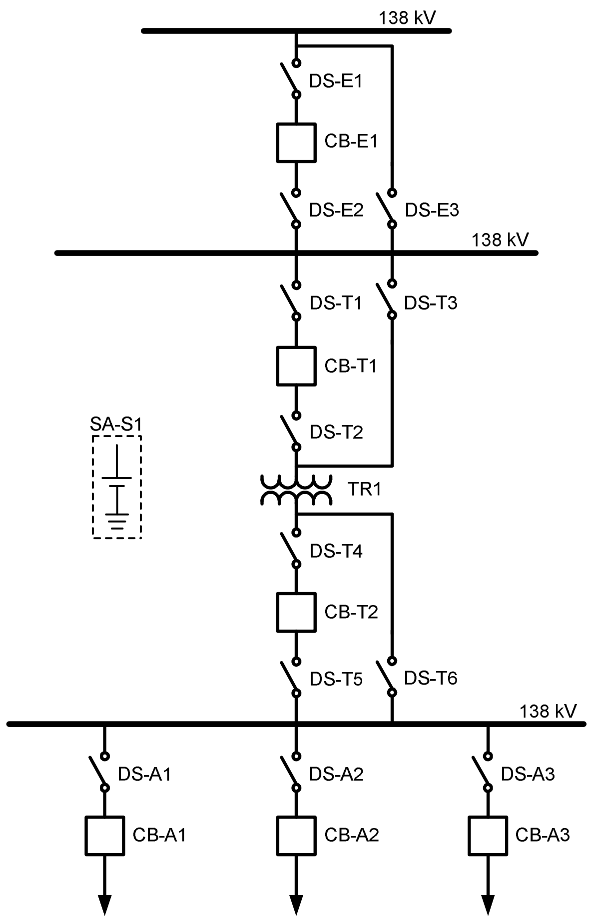

Fig. 14. One-line diagram of the simulation and test substation

The equipment monitored in this substation is shown in Table I.

TABLE I
EQUIPMENT MONITORED IN THE SIMULATION AND TEST RACK

Tag	Equipment	Monitoring
CB-E1	Incoming circuit breaker	Number of operations
		Mechanical operating time
		Spring-loading time
		Circuit breaker contact wear
DS-T1	Disconnect switch	Number of operations
		Position discrepancy
		Motor power
CB-T1	Transformer high-voltage circuit breaker	Number of operations
		Mechanical operating time
		Spring-loading time
		Circuit breaker contact wear
TR1	Power transformer	Transformer temperature
		Efficiency of forced ventilation
		Insulation aging acceleration factor
		Estimated insulation service life
CB-A1	Feeder circuit breaker	Number of operations
		Mechanical operating time
		Spring-loading time
		Circuit breaker contact wear
SA-S1	Substation auxiliary service	Voltage Vdc (+)
		Voltage Vdc (–)
		Vdc voltage level
		Detection of leakage current to ground
		AC ripple in the rectifier

To complement the simulation and test platform, a software program was developed for generating historical data to be inserted in the SMS. This software simulates the output from the data concentrator, applying data generated from all of the system variables based on time interval rules and trends selected by the user directly in the SMS manager.

Fig. 15 shows the initial screen of the SMS with the browsing options available to the user and the classification of the user access levels.

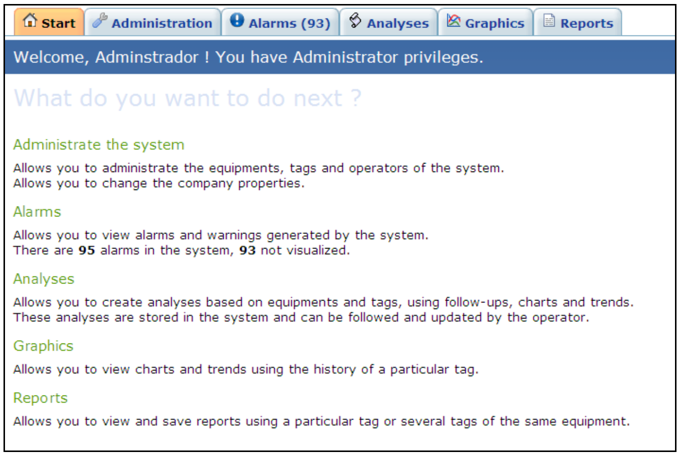

Fig. 15. SMS initial screen

Fig. 16 presents a user-performed analysis of the monitoring of the hot-spot temperature and the maximum temperature allowed in a transformer. Comments related to the analysis written by the user responsible for opening the process are stored on the system database and can be viewed by other users.

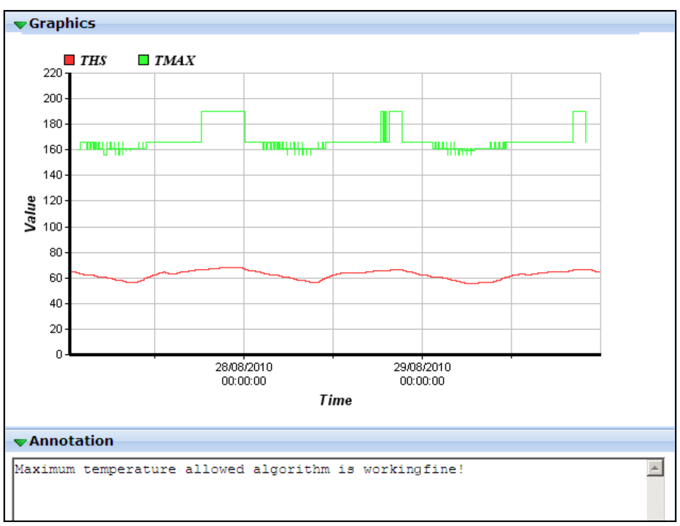

Fig. 16. Graph and analysis

Fig. 17 shows the creation of a trend line for future analysis by projecting points of the total loss-of-life of winding isolation in a transformer. This tool allows an estimation of the equipment maintenance date without performing unnecessary maintenance or shutdowns.

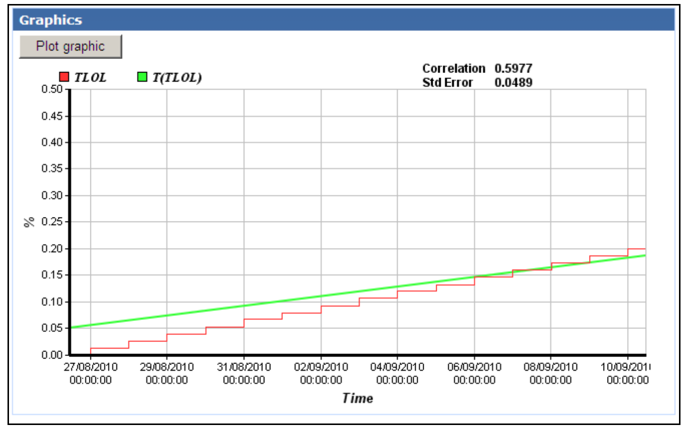

Fig. 17. Trend analysis

VIII. Conclusions and Results

Monitoring systems are essential tools to allow distribution companies to increasingly modernize maintenance techniques and migrate to intelligent and optimized predictive maintenance. Investments that are made in the acquisition of substation equipment monitoring systems add additional costs to maintenance and operation, so the minimization of these costs is a huge challenge.

The SMS is a low-cost solution for the implementation of communications infrastructure in substations using IEC 61850 protocols, where Ethernet cabling already exists, enabling its application in substations of any size and voltage level.

The SMS uses the information supplied by IEDs and takes advantage of communications network structures already in place or provided for the substation SAS. The same IEDs used for command, measurement, protection, and control form the basis of the system. They are more rugged and dependable than other monitoring devices, such as sensors or programmable logic controllers. They can capture information sent to the maintenance server, which in turn performs calculations and feeds the database. These functions are executed because the IEDs are coupled with the main equipment via CTs, PTs, RTDs, and so on.

After the practical experimentation carried out in a laboratory with a station simulator and test rack, the results were completely satisfactory and showed that the system proposed is economically viable and easy to implement.

The SMS contributes to the planning of maintenance and consequent reduction of undesirable operational costs, such as personnel overtime, in addition to influencing other costs related to the performance of equipment through the precise and reliable prognosis of events.

A cost analysis shows that the investment to add an SMS to an SAS network to modernize maintenance practices amounts to a small incremental cost of 10 to 15 percent of the initial cost of digitalization of a small distribution substation. For a larger and more complex substation, the investment to implement the SMS is an even smaller incremental cost.

IX. References

[1] S. Kimura, A. Rotta, R. Abboud, R. Moraes, E. Zanirato, and J. Bahia, "Applying IEC 61850 to Real Life: Modernization Project for 30 Electrical Substations," proceedings of the 10th Annual Western Power Delivery Automation Conference, Spokane, WA, April 2008.

[2] L. Ayers and D. Dolezilek, "Using Dynamic Real-Time Substation Information to Reinvent Asset Management," proceedings of the 3rd Annual Western Power Delivery Automation Conference, Spokane, WA, April 2001.

[3] D. Dolezilek, "Understanding, Predicting, and Enhancing the Power System Through Equipment Monitoring and Analysis," proceedings of the 2nd Annual Western Power Delivery Automation Conference, Spokane, WA, April 2000.

[4] R. Bernardes and F. Ayello, "PQMS – Power Quality Monitoring System: Improve Power Systems Through IEDs," proceedings of the 20th Annual International Conference on Electricity Distribution, Prague, Czech Republic, June 2009.

X. Biographies

Geraldo Rocha received his BSEE from Universidade Estadual Paulista Campus de Bauru, Brazil, in 2001 and specialized in electrical power systems protection at Universidade Federal do Rio de Janeiro. He worked as a protection and automation engineer for CPFL Geração de Energia S.A., where his responsibilities included maintenance, commissioning, specification, and studies of protection and automation of hydroelectric plants. In 2007, he joined Schweitzer Engineering Laboratories, Inc. as an application engineer covering the entire country of Brazil. His responsibilities include training and assisting customers in substation protection and automation efforts related to generation, transmission, and distribution areas.

David Dolezilek received his BSEE from Montana State University and is the technology director of Schweitzer Engineering Laboratories, Inc. He has experience in electric power protection, integration, automation, communications, control, SCADA, and EMS. He has authored numerous technical papers and continues to research innovative technology affecting the industry. David is a patented inventor and participates in numerous working groups and technical committees. He is a member of the IEEE, the IEEE Reliability Society, CIGRE working groups, and two International Electrotechnical Commission (IEC) technical committees tasked with global standardization and security of communications networks and systems in substations.

Fernando Ayello received his BSEE degree from Universidade Municipal de Taubaté in 1981, his MSEE degree from Escola Federal de Engenharia de Itajubá in 1985, and a Post-Graduate Certificate in marketing from the Fundação Getulio Vargas in 2000. He worked as a protection engineer at CPFL Energia from 1985 to 1991, where he was responsible for protection system studies and analyses. From 1991 to 1995, he worked as a sales engineer in the relay division at ABB and from 1995 to 2000 as a marketing engineer in the protective relay and power quality meter area at Schneider Electric Brasil. Since 2000, he has served as the regional sales and marketing manager of Schweitzer Engineering Laboratories, Inc. in Brazil. He is the author of numerous technical papers published for national seminars and conferences in Brazil.

Carlos Oliveira received his BSEE degree from Universidade Federal de Juiz de Fora in 2001 and his MSEE degree from the same institution in 2003. He worked as an automation engineer at ATI/ATITEL, Ltd. from 2003 to 2007, where he was responsible for developing hardware and software for distribution automation. He developed a DNP3 protocol communications driver, a fault detection system for a pole-mounted remote terminal unit, and IEC 61131 language programming for embedded systems. Since 2008, he has served as an application engineer for Schweitzer Engineering Laboratories, Inc. He works with communications protocols, IEC 61850 integration, and asset management systems.

20110314 • TP6493-01