INTEGRATED SUBSTATION CONTROL SYSTEM WITH EQUIPMENT MONITORING AND DIAGNOSTICS

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INTRODUCTION

Time-Based Maintenance

The maintenance of electric utility substation equipment has traditionally been time-based. From the earlier days when substations were manned and equipment could be regularly monitored, to more recent times when substation maintenance crews periodically visit substations to inspect equipment, perform measurements, record data, and extract oil samples for analysis, time has been the prime determinant for substation maintenance activity. This also includes equipment overhauls. Typically, equipment has been overhauled on a scheduled basis, i.e., equipment failure history, number of operations, age, etc., regardless of whether a malfunction or failure was determined to be imminent.

Time-based maintenance costs are significant. The expense of periodic equipment inspections, data logging and equipment overhauls have been routinely absorbed, even though the activity may not have been in response to an immediate need for preventive maintenance. This is not to suggest that for a time-based system the frequency of inspections and equipment overhauls should be extended. However, today's realities for substation maintenance recognize the inefficiencies inherent in time-based maintenance, especially when there are new dynamics influencing the utility industry.

Utility Environment

The utility environment is changing dramatically from its historical perspective. It is now an increasingly competitive arena with significant pressures for greater system reliability and improved customer satisfaction, while similar emphasis is placed on cost reduction. These required cost reductions focus on reducing operating and maintenance (O&M) expenses, and minimizing investments in new plant and equipment. If plant investments are to be made only for that which is absolutely necessary, including replacing irreparably failed equipment, the existing system equipment must be pushed to greater limits in order to defer capital investments. At the same time, the utility plant is aging. When load growth diminishes, there is a lessened need for system expansion. With fewer new equipments being installed, the average age of the system increases. In fact, [1] estimates that the age (in 1997) of 65% of all power transformers in North America is in excess of 25 years. It is expected that similar equipment aging patterns are being experienced in other countries as well.

All of these concerns surface some interesting contrasts. System reliability is expected to increase and customer satisfaction needs improvement. At the same time, decreased O&M expenditures are mandated for an aging plant that must be driven harder to minimize capital investments in new equipment.

The human resource issue is also becoming critical. All industries, including the utility industry demand that more be accomplished with less. Not only is the number of substation maintenance personnel decreasing, so, too, is the diagnostic and equipment experience base that is a critical aspect of time-based maintenance. A false economic perspective is imminent, if not already being experienced. Attrition may be lowering the historical costs of maintenance, but an increasing cost of equipment failure is an offsetting dynamic that must be considered. New substation maintenance strategies must be implemented if the requirements of today's utilities are to be met.

There is a solution to these concerns. Asset management software integrated with a substation control and equipment monitoring system can reduce operating and maintenance costs and improve service quality and reliability at the same time.

Predictive (Condition-Based) Maintenance

As opposed to time-based maintenance, which is established by the calendar, or other periodic events such as the number of operations, predictive maintenance provides for monitoring critical parameters within substation equipment so that changes in those parameters may indicate a developing problem. Predictive maintenance permits the condition of the equipment to be assessed in its operating state without the need to remove it from service for evaluations. It brings a number of advantages:

- Minimizes the need for on-site periodic tests and measurements by maintenance personnel – an obvious opportunity for cost reduction.
- Eliminates the need for regular equipment overhauls. This also has the advantage of lowering the

probability of subsequent malfunction because of improper unnecessary preventive maintenance.

- Permits scheduling and prioritizing required maintenance.
- Identifies problems in the incipient stage when corrective action is less costly. Monitoring in real time can also establish temporary operating constraints that may restrict a developing problem from increasing in severity.
- Minimizes unplanned outages – if the problem can be detected, the resultant outage can be planned to correct it.
- Extends equipment life – with a sufficient equipment database and the ability to monitor ongoing parameters, equipment life can be more accurately predicted.

Obviously, these advantages of predictive maintenance require proper monitoring and the ability to correctly interpret the data. But predictive maintenance can reduce O&M costs through the performance of maintenance only when it is required, it can improve system reliability and customer satisfaction with reductions in unplanned outages, and it can defer equipment investments by allowing for a more optimum use of existing assets. In summary, a properly implemented predictive maintenance system will contribute significantly to the operational and financial objectives of today's utility.

SUBSTATION MONITORING PRIORITIES

There are a number of areas in the substation that are the focus of real time monitoring. This paper attempts to identify those functions that receive the greatest attention, and should be the prime focus for predictive maintenance.

Load Tap Changing

Relative to power transformers, load tap changing (LTC) compartments receive a great deal of attention as an area where significant maintenance effort is focused, and where reductions in maintenance expense, particularly within time-based maintenance programs, can be realized. The latter point is important. Load tap changers are a most critical aspect of transformer maintenance because of the mechanism involved, the aspect of contact wear, which is a function of load and number of operations, and that failure of the LTC is considered a transformer failure as it typically involves a transformer winding. Reference [1] states that transformer LTC compartments incur more maintenance cost than any other substation equipment, and cause more than 40% of catastrophic transformer failures. Reference [2] suggests that 50% of the failure risk of power transformers is related to the load tap changer. It is obvious, then, that a time-based maintenance system must concentrate periodic effort on LTC overhauls, and the period would undoubtedly be conservative due to the criticality of the LTC. There are two downside aspects to this, [3]. Either the maintenance may not really be required at the time it was performed and the cost could have been deferred, or loading and other conditions on the LTC compartment may have warranted that maintenance should have been carried out much earlier than what was suggested by the calendar. Reference [3] suggests monitoring the differential temperature between the main tank and LTC compartment liquid temperatures. Normally, the LTC temperature will be less than that of the main tank. If that pattern changes such that the LTC compartment temperature becomes higher, it is an indication of excess contact wear and "coking," motor overheating, etc. The LTC motor current can also be monitored. And if the LTC tap positions can be monitored as a function of load current, an indication of relative contact wear may be discerned.

Dissolved Gas in Oil

Dissolved gas in oil analysis (DGOA or DGA) receives considerable attention as a prime candidate for transformer predictive maintenance. Time-based maintenance practices typically require the extraction of an oil sample from each transformer on a regular basis, with the sample being sent to a laboratory for analysis. If the resultant concentrations of the various gases were found to be within acceptable limits, another sample would be taken after the next elapsed time interval. If, however, a concentration of a gas or gases was determined to be outside of limits, then that transformer would be monitored more closely, with more oil samples being taken for analysis.

This demonstrates another deficiency of time-based maintenance. If the results of periodic DGOA are recorded in a data base, a reasonable history of the transformer is developed, but it is a history of "snapshots," that are periodically taken. When a sample is taken that indicates an anomaly, there is no information regarding the timing of the change in concentration. In [4], the authors state that 98% of transformers sampled have gas analysis results that are within an acceptable gas concentration for those individual transformers, although the sample concentrations may be different. The authors also state that changes in gassing levels, and even more importantly, the rates of change in gassing levels are the more significant requirements of DGOA. If on-line DGOA monitoring is installed, changes and rates of changes in gas evolution can be alarmed. This points out the advantage of predictive maintenance. By contrast, in a time-based system, a serious problem could otherwise develop between visits to transformers.

Assuming that gas in oil analysis monitors can detect and report gas concentrations reliably, they should not be solely relied upon to determine the status of the transformer's health. Because gases develop due to various conditions at the transformer such as loading, the top oil and winding temperatures, and ambient temperature conditions, etc., a more realistic diagnosis can be made if these other factors are monitored as well, and their data combined with the results of the dissolved gas analysis. The presence of an increased concentration of a certain gas may not necessarily indicate an internal problem if the transformer was operating at an elevated temperature because cooling fans had failed. Predictive maintenance for transformers requires a number of parameters to be monitored such that the most likely cause of a problem can be determined.

Transformer monitoring beyond DGOA is also very important from the perspective of asset management. If the utility is striving to defer capital investment, knowledge of the history of the power transformer, as well as current and potential load levels, and hot spot and top oil temperature levels is essential. This will permit a more clear view of the thermal stresses the transformer has experienced, and its current thermal conditions such that the transformer's life can be better estimated as a function of anticipated future loading.

High Voltage Bushing Integrity

High voltage bushings, particularly those installed on power transformers, also receive a great deal of maintenance attention in that the failure of a bushing can be catastrophic for the entire transformer. Although they have effectively been tested within time-based programs with the transformer removed from service, a predictive maintenance system allows for the bushing to be monitored in real time under actual operating conditions, e.g., temperature, such that power factor and capacitive charging current can be definitively measured. Breakdown of the bushing's insulation can result in alarms that may provide maintenance personnel the time to avert a catastrophic problem. This was indicated in [5], which discusses a utility with a large installed number of problematic transformer bushings. Early indication of potential bushing failure through on-line, predictive maintenance proves an obvious advantage for that utility's maintenance organization.

Partial Discharge

Partial discharge in a power transformer is a key indicator of a breakdown occurring within the transformer's insulation, although it may not indicate a complete breakdown. If detected, it provides information that justifies either removing the transformer from service or more concentrated partial discharge monitoring [5].

Partial discharge detection is most likely an adjunct to dissolved gas in oil analysis. The nature of the difficulty within the transformer can be determined from the analysis of the gases in oil. For example, acetylene is a resultant gas caused by arcing.

DGOA, however, while providing useful information regarding the potential problem(s) within a transformer, cannot pinpoint the physical location of the problem. Partial discharge, using acoustic sensors and triangulation was reported in [6], with fault location to within 50 mm.

The use of acoustic sensors to detect partial discharge must be able to overcome background noise, and its cost may not justify wide-scale deployment. However, if DGOA establishes the potential for a problem, or if an unusual system condition such as a lightning strike to a substation occurs, temporary partial discharge monitoring for those transformers that experience the strike may be justified.

Circuit Breaker Monitoring

Reference [7] states that more than half of substation maintenance expense is spent on circuit breakers, with an estimated 60% of the total allocated for overhaul. Predictive maintenance systems for circuit breakers have the potential for providing significant reductions in substation maintenance costs.

The challenge for predictive maintenance systems for circuit breakers is the recognition that the maintenance expense is directed to existing circuit breakers, which utilize different interrupting technologies. Contrasted with power transformers, whose operating principles, and, therefore, their monitoring requirements are essentially the same regardless of manufacturer; circuit breakers in use today use air, oil, vacuum, and SF_6 gas as interrupting media. While circuit breaker manufacturers may develop a monitoring system for what they offer today, the greater need is to install monitoring systems that can be retrofitted to existing circuit breakers of various technologies in a non-intrusive manner, and to provide for compatible data acquisition and processing.

Circuit breakers are also a different breed of substation equipment. As opposed to a power transformer, which is continually performing its function; to a large extent, an energized circuit breaker is generally in a quiescent state, which is indicative of a well-designed, highly reliable system. But when a circuit breaker must operate, a misoperation, or failure to interrupt can create a severe system disturbance. Off-line testing, particularly for those breakers that operate infrequently, may be a cost-effective process coupled with a predictive maintenance system.

Reference [7] suggests the following circuit breaker parameters to monitor:

- SF_6 gas pressure
- Breaker position
- Contact travel
- Auxiliary switch position
- Trip and close coil currents
- SF_6 hydraulic, and air pressures
- Run time of pumps
- Number of operations
- Contact and nozzle wear

Most of these requirements apply to all interrupting media. For oil breakers, they would include the oil's dielectric strength as an additional need, and vacuum breakers would require loss of vacuum detection.

In addition, in the United States, [8] establishes SF_6 as being defined by the United States' Environmental Protection Agency (EPA) as a strong greenhouse gas. The utility industry is reported to use 80% of the total SF_6 production.

Although EPA has not established any regulations relative to the use of SF_6 or leaks from equipment using SF_6, a growing attitude of "if SF_6 is not leaking, why are you buying it?" coupled with a price of SF_6 approaching $35/pound, suggests that SF_6 density monitoring, (pressure, temperature) may be justified. Such monitoring conceivably can provide alarm data regarding the point in time when the volume of SF_6 within the breaker will approach a level of criticality.

Substation Monitoring – Current Status

There are a number of sensing devices that have been developed to provide data regarding the parameters to be monitored that were described previously, and sensor development, e.g., DGOA, is continuing. In many cases, however, they are individual monitors that use proprietary protocols for communications, with software that is unique to each device. Thus, the user must become familiar with a variety of individual proprietary systems in order to monitor a number of different equipments. Not only is this contrary to the current trend in utility human resources, it also does not provide for a common database or a single, composite view of the substation.

The Totally Integrated System

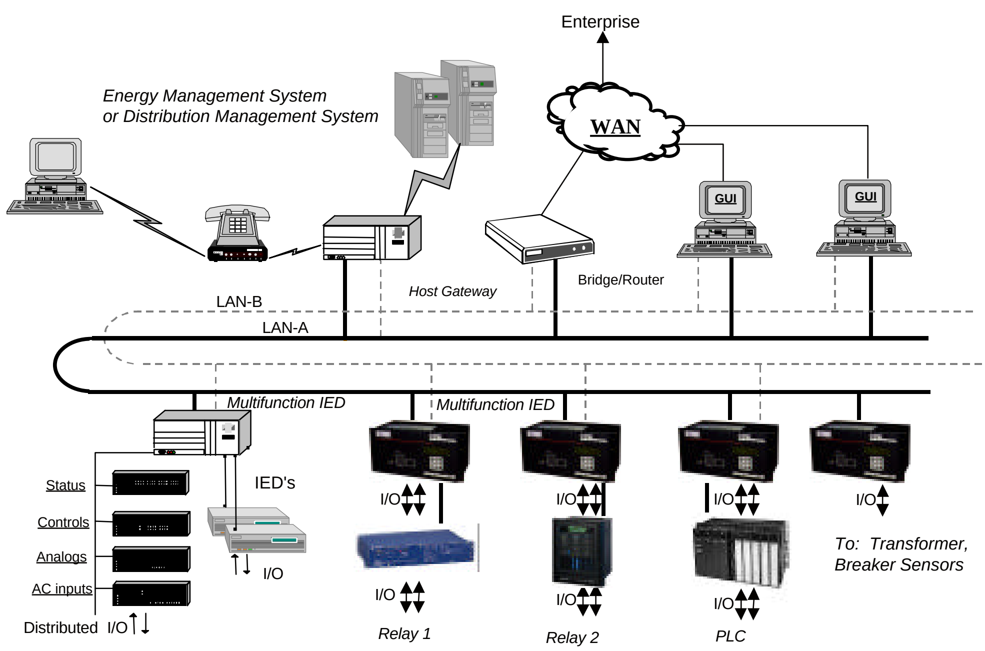
What is needed is a totally integrated system which can provide data from all sources within the substation for predictive maintenance and diagnostics, without the need for redundant equipment, or systems. The system should be able to integrate equipment of different functionality and from different suppliers into an "open" architecture, and tie into a common communications platform that permits a number of sensors and other intelligent electronic devices (IED's) to communicate as needed.

Substation Control Systems (SCS) (Figure 1) are supplied by substation automation systems vendors in order to provide a platform for integration of multi-purpose IED's into a single, integrated control and data acquisition system. Utility systems operations people have been using SCS's, and earlier remote terminal units (RTU) to monitor and control their electric networks. Since SCS's integrate data from multiple IED sources such as RTU's, relays, metering, power quality monitors, programmable logic controllers, and digital fault recorders onto a single computer platform for data processing and operator display; the SCS becomes the logical platform for the integration of equipment monitoring and diagnostic functions as well. Clearly, what is *not* needed are two separate systems in the substation, one system to provide for predictive maintenance, and the other to provide for the traditional data acquisition and control requirements. Inasmuch as the two objectives are somewhat interdependent, they should be part of the same, integrated system.

The predictive maintenance system should also be directed towards reducing workload, improving the understanding of the operating capabilities of existing assets, providing guidance to operations and maintenance personnel, and most importantly, providing reliable *information*, and not simply data.

Figure 2 provides a concise summary of how a predictive maintenance system can contribute appropriate data for a number of functions that can be applied within the utility enterprise. It demonstrates how the data acquired from equipment monitoring, e.g., dynamic loading, can be used by both engineering and planning organizations to project the implications of the end of equipment life.

Figures 3 and 4 describe a means through which transformer and circuit breaker diagnostic monitoring can be integrated onto the substation's communications infrastructure in the same fashion as data from other IED's such as relays and programmable logic controllers.



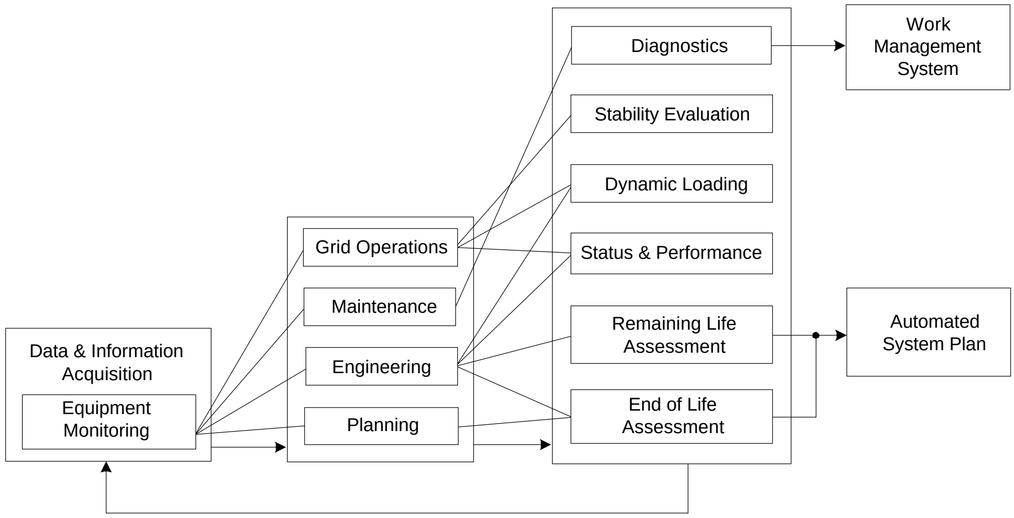


Figure 2. Data and Information Acquisition.

Most importantly, the multifunction IED's that provide the interface between the equipment sensors and the system's man-machine interface (MMI) can have diagnostic capability imbedded within such that the IED can provide an alarm and be the first line of defense against an eventful equipment failure.

Monitored Data Analysis

In general, however, the composite raw data collected by the substation control system (SCS) from the various equipment monitors will typically not provide *information* to the system operator regarding the current health of the monitored equipment. Problems can either develop over a short period of time, and may not be readily detectable without analytical rules, or they can evolve over time, as with a collective number of tap changes or circuit breaker operations.

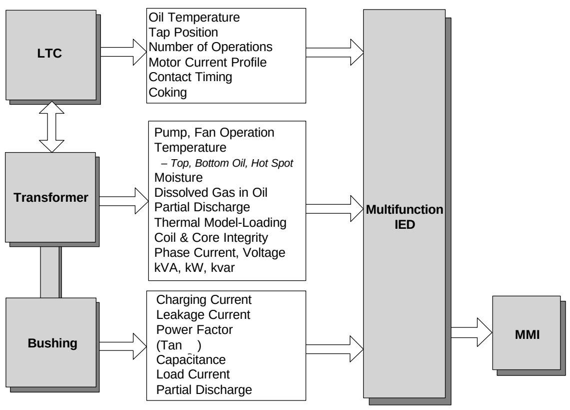


Figure 3. Transformer Condition Monitoring.

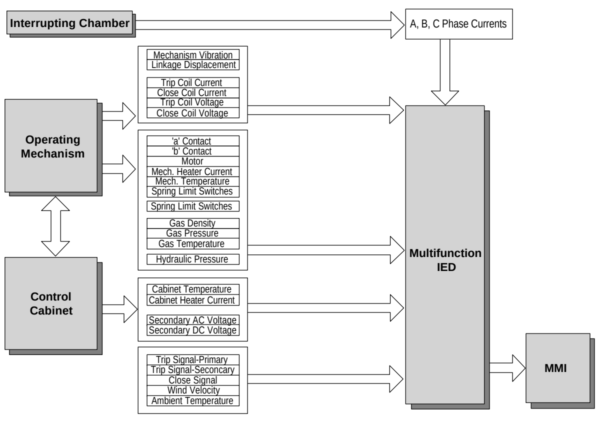


Figure 4. Circuit Breaker Condition Monitoring.

Statistical process control (SPC) techniques, which have been used by manufacturers for years, can be applied to the data collected by the SCS to determine whether the equipment is operating within acceptable limits.

Predictive maintenance of circuit breakers, for example, lends itself to a statistical evaluation of monitoring various breaker functions. The complexity of a circuit breaker suggests that certain parameters such as the time between initiation of a trip signal and contact separation may display some statistical variance, which is a key concept underlying the application of SPC. Reference [9] establishes that deviations from a calculated mean value would permit evaluations of the changes occurring in circuit breaker operation. The magnitude of the deviation and its value above or below a mean can be interpreted as either normal operation, or the development of a problem because the deviations are too great and/or they begin to drift systematically in one direction from operation to operation.

This is illustrated by Figure 5. At the initiation of data collection, the measured values exhibit small deviations about the mean in a random pattern. As time progresses, the measured values begin to deviate from the mean in greater amounts, and also on the same side of the mean. This data analysis establishes that warning and action limits can be determined by the SPC process.

The development of control limits also recognizes that some monitoring activity such as determining gas pressure and temperature is continuous, as opposed to monitoring operating parameters such as breaker trip coil current, which is intermittent over time. The control limits developed much recognize this difference.

As the statistical evaluation develops, rules will be applied to the data received from the monitors that can detect with

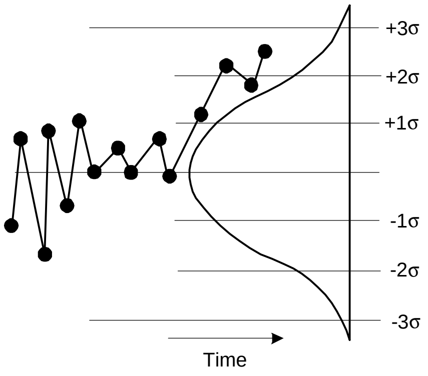


Figure 5. SPC Process.

greater probability a process which has become unstable and may be failure prone. For example, any of the following conditions could define instability (refer to Figure 5):

- 2 of 3 consecutive samples > 2σ from mean on the same side
- 4 of 5 consecutive samples > 1σ from mean of the same side
- 9 consecutive samples on one side of the mean, or
- any single sample outside a control limit (3σ).

ECONOMIC JUSTIFICATION

The obvious question that is raised relative to a predictive maintenance system is the justification of its cost. In some cases, this becomes a non-issue in that a time-based maintenance system no longer is justified for the reasons stated previously in this paper. Nevertheless, there is quite often the need to at least explore the economics. In the development of this paper, it is recognized that time will ultimately determine the savings provided by a preventive maintenance system. However, interesting insights can be drawn if a breakeven analysis is performed. That is, given an assumed cost of a preventive maintenance system, and a known value of annual maintenance expenditures, the required reduction in maintenance cost that will breakeven economically against the monitoring system is determined. The following example illustrates the process. The evaluation follows the practices of investor-owned utilities in North America.

Annual Maintenance Expense	Fixed Change Rate	Cost of Capital	Cost of Monitoring System
$25,000,000	17%	10%	$15,000,000

With those assumptions, the annual maintenance expense must be decreased an average of 6.6% for breakeven. If the monitoring system's cost was $25,000,000, the annual breakeven reduction increases to 11%. Clearly, such reductions in annual maintenance costs will easily be exceeded. If the probability of avoiding a catastrophic failure, and additional deferred capital investment are also included, the evaluation becomes even more positive. It is reasonable to assume then, that preventive maintenance systems will be economically and operationally attractive.

CONCLUSIONS

As utilities today continue to downsize and reduce operating and maintenance expenditures, it must be understood that utility systems do not correspondingly decrease in complexity nor in criticality for service reliability. Despite the historical perspective that utility system availability has been high, there are increasing pressures to improve, at a time when resources are diminishing. Real-time, predictive maintenance data being processed through an intelligent system is an emerging requirement to understand the condition of substation equipment. This will allow:

- Safe and reliable equipment operation.
- Asset operation at optimum performance for current conditions.
- Extension of maintenance intervals without decreasing system reliability, while performing maintenance in time to avoid failure.

As utilities move towards the application of integrated substation control systems, a natural adjunct includes the integration of an equipment monitoring and diagnostic system that will allow the predictive maintenance required in today's utility environment.

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