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editorial

The electric utility industry has been on a journey to add intelligence
to the grid for almost 50 years.

our continuing GRID MODERNIZATION JOURNEY...

Mark Adamiak
Chief Application Architect
GE Digital Energy

The phrase "Smart Grid" is a fairly recent introduction into the public vernacular. The electric utility industry, however, has been on a journey to add intelligence to the grid for almost 50 years. The rational for this journey was clearly articulated on the day of the 1965 east coast blackout, by then US President Lyndon Johnson, in the note he sent to the chairman of the then Federal Power Commission. He noted that: "Today's failure is a dramatic reminder of the importance of the uninterrupted flow of power to the health, safety, and wellbeing of our citizens and the defense of our country". In the resulting blackout report, recommendation #10 identified the need for a: " ... study of the adequacy of automatic equipment, communication facilities, recording facilities, and operating procedures in the dispatching and control centers and in power plants during emergency conditions" - thus launching the US industry down the road of grid modernization. Similarly, these types of statements and calls to action have been heard in other parts of the world as they work to address the challenges of grid reliability.

Although a future vision for the grid existed, the technology to implement that vision has lagged behind. The new focus on grid modernization efforts has been enabled by the introduction of cost effective new technologies to sense, communicate, analyze, and predict, providing operational awareness of the power system and its connected assets.

Just as advanced detection of human health problems enables a wider range of medical solutions, advanced detection and monitoring techniques applied to power system equipment enables planned responses to ensure better maintenance and operation of primary and secondary equipment. It is becoming increasingly clear that future monitoring will be able to provide us with a dynamic pulse on the health of the power grid – allowing engineers to not only detect failures but to identify components that are starting to fail.

From primary substation assets, like transformers and circuit breakers to distribution automation controllers, sensors and switches, having the ability to remotely monitor and control power system assets is fundamental to moving towards a truly modern, reliable, and efficient grid.

Previously known as the Protection & Control Journal, this inaugural issue of The Grid Modernization Journal takes a broader look at the primary equipment, intelligent devices and sensors, automated controllers, and grid management tools that are now become ubiquitous with our modern grid. From monitoring and trending transformer oil temperature and estimating remaining life using advanced multi-gas monitoring to substation automation and digitization across utility and industrial applications, we explore and discuss some of the very technologies being piloted and deployed throughout power systems around the world.

can social media improve grid reliability?

Reliability will be the top priority for grid operators
no matter whom or where they serve.

John McDonald, GE Digital Energy, IEEE

Integrated systems
and social media to improve grid reliability and
CUSTOMER SATISFACTION

These developments and their application can provide utilities with a clear path through the smart grid woods and maintain their focus on the most important factor that guides their work: power grid reliability.

Introduction

Reliability will be the top priority for grid operators no matter whom or where they serve. From a tree branch that takes out a single home to a complex, multifactor event that cuts power to 700 million people—as a two-day event did in India this past summer—rapid outage detection and speedy restoration play critical roles.

Regulators assess utilities' performances partly on reliability indices sometimes referred to as SAIDI (System Average Interruption Duration Index) and her sisters: SAIFI (System Average Interruption Frequency Index), MAIFI (Momentary Average Interruption Frequency Index) and CAIDI (Customer Average Interruption Duration Index), and it is challenging to keep these numbers within acceptable limits. These indices are based on IEEE Std 1366.

As intelligence is extended down into the distribution system, much data can be generated if used properly by an integrated system of outage detection and power restoration and can help utilities improve on critical indices. This can be done using available technologies. In addition, GE Digital Energy recently developed a patent-pending software application that can monitor social media to provide speedy, granular data to assist these efforts. The attractive secondary benefit is customer engagement and satisfaction.

These developments and their application can provide utilities with a clear path through the smart grid woods and maintain their focus on the most important factor that guides their work: power grid reliability.

In describing how to improve outage detection and power restoration, there is an integrated approach to distribution automation that takes advantage of the strong business case, such as fault detection, isolation and restoration (FDIR) and integrated volt/VAR control (IVVR). For utilities that have installed advanced metering infrastructure (AMI) and interval smart meters, this is a logical step; however, AMI isn't necessary to reap the benefits of the approach outlined here.

Remember, automated substations that can trigger switches to isolate faults without operator intervention still leave utilities to rely on customers to call about outages. That's why advocating a more integrated approach to full distribution system automation will improve multiple benefits for the business case and utility performance on outage-related indices. Distribution automation's business case improves markedly if the driving focus is speedy outage detection and power restoration.

Replacing the Phone Call

Smart meters record electricity usage for billing, measure end-of-line voltage and, in the case of an outage, emit a last gasp as they lose power. Capacitors are designed to hold enough charge to get that crucial message out. That's almost instant, more precise and quicker than waiting for customers to call—sometimes the difference between an outage's falling under MAIFI: a momentary outage; and SAIFI: a sustained outage.

For utilities without interval meters and AMI, voltage-sensing meters can be placed strategically at the ends of feeders to ensure compliance with American National Standards Institute (ANSI) standards for delivering 114 V to 126 V of power. Those meters can play a role in outage detection, though a less granular one than full AMI metering. That's where GE Digital Energy's new software application for social media will be useful.

A traditional customer phone call could be linked to a physical address by tapping into the customer information system. With the widespread use of social media, we can link customers' tweets to an address to obtain similar information. This can be done in various ways. The utility could incentivize customers to link their Twitter tags to their account information or to turn on their mobile devices' geo-tagging functions, which provide latitude and longitude that indicate their locations when they tweet instead of
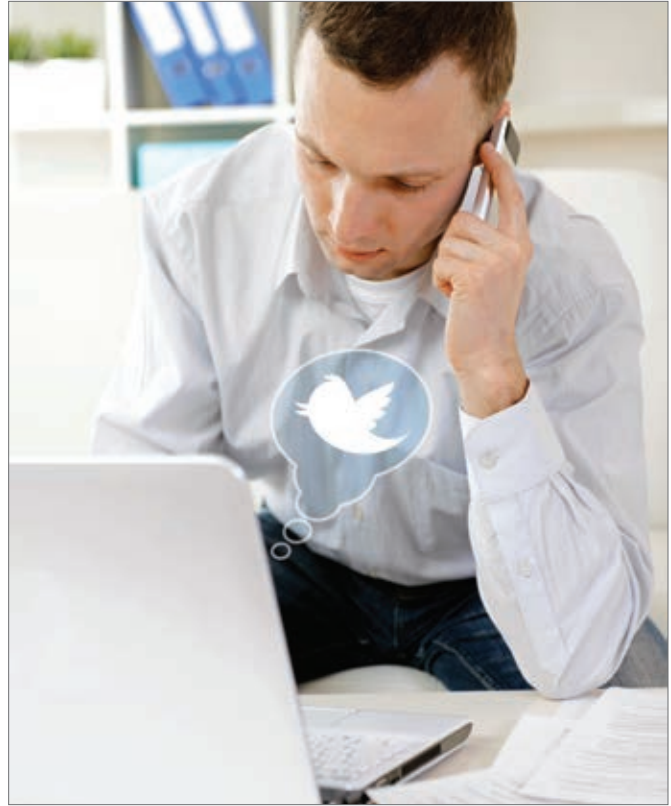
RELIABILITY WILL BE THE TOP PRIORITY FOR GRID OPERATORS NO MATTER WHOM OR WHERE THEY SERVE. FROM A TREE BRANCH THAT TAKES OUT A SINGLE HOME TO A COMPLEX, MULTIFACTOR EVENT THAT CUTS POWER TO 700 MILLION PEOPLE.

call. A cluster of tweets tied to addresses—the greater the sample, the greater the accuracy—can be subjected to automated analysis to provide the precise location and extent of an outage. Grid IQ Insight is a new software platform with geospatial coordinates for automated systems that can connect tweets with an outage management system.

Getting customers to work directly with their utilities takes time and effort. Customers are more likely to tweet one other to complain of outages. The new software application uses text mining to understand whether a flurry of tweets that mention "outage" and "power" really refer to a "power outage," and if so, can mash up that data with end-of-line sensor data to identify the location and extent of an outage rapidly. Because each household has multiple members and an electricity account holder might not be the one tweeting, this method provides an attractive alternative for utilities without AMI. The analytics software that determines the location of outages in both instances resides in the utility's outage management system (OMS) platform but remains a separate function.

Replacing Truck Rolls

Crowdsourcing the cause of an outage by leveraging customers' use of still and video camera capabilities on ubiquitous mobile devices is another social media benefit to utilities. Incentivizing customers to post their pictures and videos of downed lines to a utility's Facebook page while emphasizing traditional cautions about approaching high-voltage situations could provide images to be analyzed by automated image-assessment software to better inform field crews prior to truck rolls.

Even where AMI is installed, there's only one meter per household. Data show that each household has multiple social media accounts, potentially multiplying the number of resulting data points. The current 200 million Facebook accounts in the U.S. represent about one account per household, and that number is growing. Using social media, as parents know, often is preferred to making phone calls. An app could reduce outage notification to one click. As generations shift, these trends will become more pronounced.

We see in these trends immediate operational benefits tied to outage detection and power restoration plus the seeds of significant customer interaction and the larger field of general consumer engagement. Educating consumers about the economic and societal benefits of a smarter grid will be the first step in creating a smart grid social network. That network will function much like the smart grid—with open, collaborative, two-way information flow between consumers, the ultimate deciders of smart grid, and utilities, the ultimate providers of smart grid. That interaction will lead to customers' education in and acceptance of a new utility-customer paradigm in which customers understand and willingly participate in critical utility programs such as demand response. That participation will signal a human smart grid, and it should reflect customers' understanding of electricity's role in the macro economy, as well as their own lives and prosperity.

Once consumers in general grasp that energy efficiency, demand response and active energy management have positive implications for their pocketbooks, economic security, energy independence and the environment, they will become the utility's partners in achieving those goals. As utilities seek to defer new capital investment where possible, wring efficiencies from the grid and move from fossil fuels to more renewable and sustainable sources, they'll find that an educated, cooperative customer is one of their most valuable resources. Utilities will learn to be customer-savvy, responsive and conscious of opportunities to add value to their commodity and its delivery.

Tying it All Together

Now we've got outage data, either through AMI or end-of-feeder sensors, plus social media. How that data is routed and analyzed is critical to speedier power restoration. A well-designed communication network will enable smart meters' last gasps to trigger near-instant automated switching. Without AMI, but by combining end-of-line sensor data and social media data, operators play an active role. Outage detection and power restoration will be speedier than relying on customer phone calls, especially if the applications run closed loop and remove the operator from the decision-making process.

Automation in this case has three components: a control center master, field equipment and a communication network. All three factors impact performance and cost. The advent of public networks, mostly wireless, has provided the tipping point for the distribution automation business case. It's finally cost-effective to provide a reliable data network across a large geographic area, whether that network is public or private. Communication network performance is measured by three variables: response time, bandwidth and latency. Utilities' performance requirements allow different response times for different applications, such as a switch's needing two seconds, analog information's needing 15-30 seconds, and a capacitor bank can be triggered in 30 seconds. Bandwidth is measured in bits per second: How much data and how quickly can the sequence of events be reported? Latency refers to how much delay is acceptable in transmitting or receiving signals.

The network design must balance overhead on the system with the speed needed for various signals. For instance, cybersecurity and cryptographic requirements will introduce latency into the signal path; a 200-300 millisecond latency can become a 600-800 millisecond latency when cryptography is applied. Industry standard communication protocols (e.g., DNP3) introduce overhead, as well, and the communications system bandwidth might need upgrading to maintain the same update rate at the control center master.

Most utilities will employ a hybrid communication network. At larger substations, utilities might use fiber-optic cable or licensed wireless frequencies. Smaller, peripheral substations require only unlicensed spectrum for wireless radio. Downstream of the substation, the solution likely is a wireless private network, considering response time, bandwidth and latency requirements, as well as cost.

Routing Signals

Another challenge is to integrate outage and verification messages from the meters or end-of-line sensors through the substation to the control center and its OMS. AMI systems typically are designed to support only meters' interval data, which travels from meter to the head-end system to a meter data management system (MDMS) for storage and analysis. The AMI is not designed for voltage data or the meters' last gasps, which need to be routed around the AMI's path and directed into a distribution management system (DMS) or an OMS. The DMS will use voltage data to populate a network model, and an OMS is the proper destination for last-gasp signals.

These separate paths reflect the distinction between operational data and nonoperational data, and proper data routing around the AMI system is a nascent functionality that utilities must demand from vendors. Utilities should focus on operational data in this context, but vendors must enable utilities to extract more value from the nonoperational data coming out of IEDs, which will provide value to asset management, maintenance and power-quality efforts.

UTILITIES CAN IMPROVE THEIR RELIABILITY INDICES AND BEGIN TO ENGAGE CUSTOMERS IN A VIRTUOUS CYCLE THAT FURTHER CONTRIBUTES TO SPEEDIER OUTAGE DETECTION, POWER RESTORATION AND CUSTOMER SATISFACTION.

DMS in Outage Management

Consider the DMS's role in an integrated system. DMS relies on a network model generated from geographic information system (GIS) data and is populated by substation and feeder intelligent electronic devices and voltage data from end-of-line sensors. A network model manager interfaces with a GIS so it knows what data to pull from the GIS to build a three-phase, unbalanced DMS network model.

A utility needs four applications on a DMS: the aforementioned FDIR and IVVR, optimal feeder reconfiguration (OFR) and distribution power flow (DPF). Protective relays detect a fault, its location and type. Then the FDIR isolates the faulted segment of the feeder and restores power to customers on healthy segments of the feeder using the OFR. An OFR can look ahead to account for switching schedules for routine maintenance to optimize its role.

All this should happen in less than five minutes, keeping an event within the MAIFI index for most customers and not impacting SAIDI, SAIFI and CAIDI.

Although IVVC is only incidental to outage management, it plays a big role in DMS, optimizing voltage and reactive power for energy efficiency.

The DPF is an online tool that allows the operator to simulate the results of switching strategies and thus contributes to energy efficiency by controlling losses and loading on feeder lines. These two related functionalities make an outsized contribution to the business case for integrated distribution system automation. The suite of functionalities available through FDIR and IVVR comprise the best business cases for adding intelligence to the distribution system in the United States.

Advancements in data visualization tools such as dashboards make all the interactions described here graphically clear to the grid operator in the control center and, in circumstances requiring operator action, give data in the form of actionable intelligence.

With all the aforementioned elements in place plus that crucial two-way communication with the customer, utilities can improve their reliability indices and begin to engage customers in a virtuous cycle that further contributes to speedier outage detection, power restoration and customer satisfaction.

Utilities must weigh the larger value of increased reliability and its impact on customers, regulators and other stakeholders.

investing in continuous transformer testing

Reliable electricity supply has never been more critical or politically sensitive
for the world's economic and social development.

Elizabeth MacKenzie, Dr. Elm Costa i Bricha

Field results
from an integrated on-line transformer tank and bushing
MONITORING SYSTEM

On-line monitoring and diagnostics is a useful tool to help operators manage their assets and make decisions on continuing operation, maintenance or replacement.

Preventing Catastrophic Transformer Failures

Introduction

Transformers are a critical part of an electrical utility's asset base. Loss of a transformer in a transmission utility, generation plant or industrial plant can cost many millions of dollars, depending on how long it is out-of-service.

On-line monitoring and diagnostics is a useful tool to help operators manage their assets and make decisions on continuing operation, maintenance or replacement. Transformer bushings have been identified as the cause of a large number of transformer failures and GE has developed an on-line bushing monitoring system that will monitor the bushing insulation and also detect partial discharge (PD) within the bushing and tank.

The bushing/PD monitoring system can be integrated with GE's existing DGA monitors. It uses sensors on the bushing tap of the transformer to measure the low frequency and high frequency components of the leakage current, to identify changes in the bushing insulation properties and to detect partial discharges within the bushing and transformer tank. This paper describes the results of field trials of the integrated system on a transformer.

The world faces major challenges with respect to growing the electrical power infrastructure while continuously improving its reliability. Failures of critical transformer assets in both public and private power networks have social consequences (provision of electrical power to consumers), but also impact industrial production and productivity. Reliable electricity supply has never been more critical – or politically sensitive – for the world's economic and social development.

The fundamental design of the power transformer has not been altered significantly over the past 100 years. However, the impact and value of losing critical load due to transformer failure has increased by many orders of magnitude. Today, global services and industries alike are critically dependent upon reliable electric power supply.

Key parameters of the transformer and its 5 major components- the active part (core and windings), oil, bushings, on-load tap changer and the cooling system - can provide useful transformer "information" to allow network and asset owners/operators to make better technical, operational, and hence business decisions.

Grouping of transformer failures into the 5 major component categories shows that bushings and tap changers are as critical as the active part in terms of the root cause of failure.

In the quest to improve reliability, reduce unplanned outages and avoid catastrophic failures, customers have been turning to transformer failure data to see what caused the failures and what monitoring equipment was required to protect the asset.

Often that meant going to various vendors, sourcing individual equipment and trying to get them to communicate to a central system. GE offers a complete integrated solution to cover the major source of failure for transformers.

Main Tank — 30% of failures — DGA monitoring and PD detection — Hydran M2, Kelman Transfix, Intellix BMT 300

Tap Changer — 35% of failures — DGA monitoring — Kelman Taptrans

Bushing — 15% of failures — Bushing monitoring — Intellix BMT 300

Cooling System — 5% of failures — Transformer models including cooling efficiency — Intellix MO 150
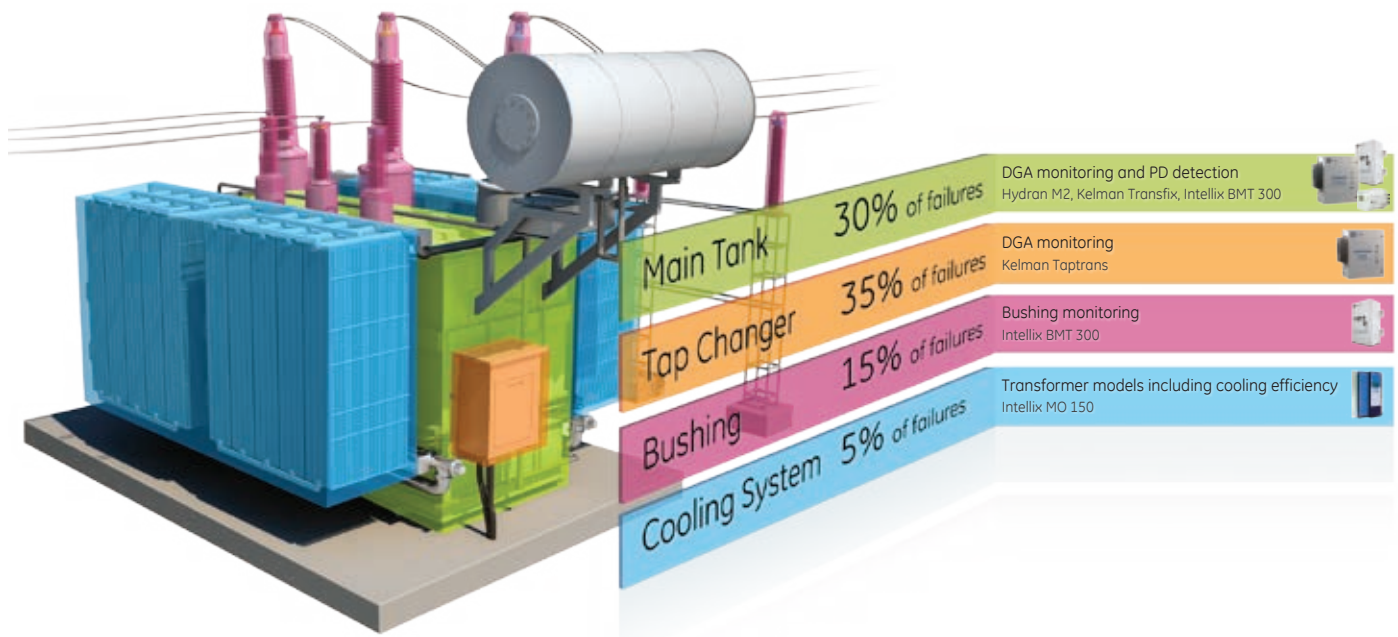
Bushing Failures

Figure 1. *Transformer Failure Causes*

Faulty insulation is the principal cause of bushing failure. Humidity and oil ageing are major factors in insulation breakdown.

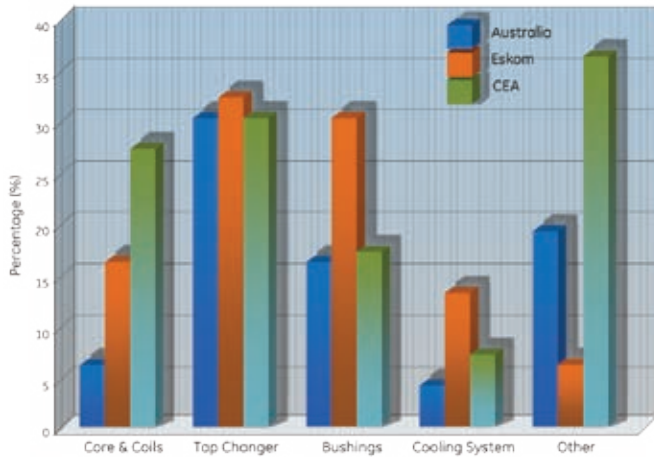Table 1 below shows the main causes of insulation failure in condenser (bushing) insulation. Progressive insulation breakdown leads to a flashover inside the bushing and often to catastrophic failure where the porcelain shatters, endangering personnel and other equipment in the vicinity. It can also lead to fire that destroys the transformer and surrounding equipment.

Typical Defects and Faults	Failure Mode
• Residual moisture • Poor impregnation • Overstressing • Ingress of moisture • Ingress of air • Oversaturation with gas • Aging of oil and oil paper body • Thermal instability of oil • Gas unstable oil • Copper migration • Dielectric overheating • Incipient ionisation • X-wax deposit	• Critical ionisation • Puncture • Explosion • Thermal instability of the oil/paper dielectric • Exponential increase of dielectric losses and temperature

Table 1. *Bushing Condenser-type Insulation Failure Modes*[5]

Bushing and Partial Discharge Monitoring

The traditional system of bushing checking is based on measuring the dielectric loss of insulation, also known as dissipation factor, at a voltage of 10 kV4 at the power system frequency. A Schering Bridge is used to measure the bushing capacitance and dissipation factor. This involves taking the transformer out of service to apply the voltage and make the measurement under no-load conditions.

On-load bushing monitors have been developed that measure the current in the bushing capacitance tap, replacing the earth connection in the tapping point with a current sensor. These current sensors also have built-in protection to ensure that the bushing foil is effectively earthed in the event of open-circuit on the measuring cable or some other fault in the measuring equipment.

The advantage of on-load monitoring is that it can be carried out with the transformer in service condition and does not require an outage of what is often a critical equipment. The disadvantage is that, without any reference voltage, the actual capacitance and dielectric loss cannot be determined. The measured value is relative, but any changes over time can be monitored.

One other advantage of on-line measurement is that partial discharge (PD) in the transformer can also be detected by measuring the high frequency component of the bushing capacitance current. Partial discharge from within the transformer,

HAVING AN INTEGRATED MONITORING SOLUTION WILL SIGNIFICANTLY INCREASE THE ABILITY TO DETECT POTENTIAL TRANSFORMER PROBLEMS WHICH CAN LEAD TO CATASTROPHIC FAILURES.

as well as the surrounding environment, is transmitted through the capacitance layers of the bushing and can be detected as a high frequency signal on the bushing tap current. Different means can be used to discriminate between internal and external PD.

For this project, different types of measurements were assessed. The first included a sum-of-currents method that measures the sum of bushing capacitance currents on the three phase bushings, and monitors any change in magnitude and phase angle of the current.

It is considered that the parameters of the insulation of all the bushings on the three phases of the transformer cannot change simultaneously and to an equal degree. The unbalance current (stress), isolated on the summing resistor of the instrument (UNN, see Figure 2a), always alters with the appearance of insulation defects in one or two bushings.

The first method uses the magnitude of the unbalance current to characterize the degree of the development of a defect in the bushing insulation. Caution and Alarm limits can be set on this value. The three-dimensional direction of the vector of the unbalance stress indicates the phase of the bushing in which the insulation parameters have changed (Figure 2b).

The second method measures the individual currents on the three phases. The magnitude of the current is a measure of the capacitance of the bushing and a change of current magnitude indicates a change of capacitance, and hence insulation failure. This is expressed as a relative value, as there is no reference.

Bushing Measurements

In addition, one bushing is used as a reference and the phase angles of the other two bushings are measured relative to this angle, giving phase angle A-B and A-C, or relative tgd. Changes in the phase angles provide information about changes in the tgd of the individual bushings. All of these parameters can be trended to show changes in the bushing insulation over time.

Both methods require the basic parameters of the bushings to be entered into the system during commissioning, usually from a recent off-line power factor and capacitance test, or from the bushing rating plate and initial commissioning test report.
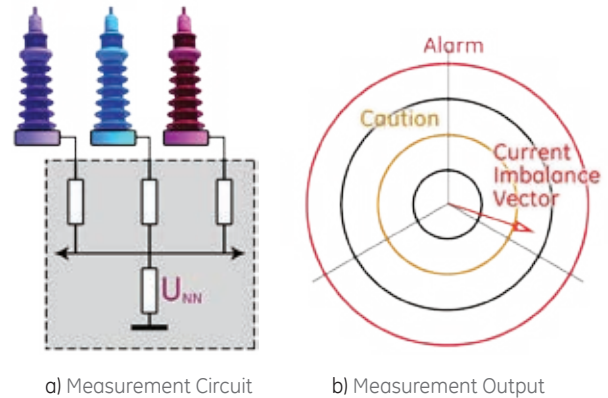

a) Measurement Circuit   b) Measurement Output

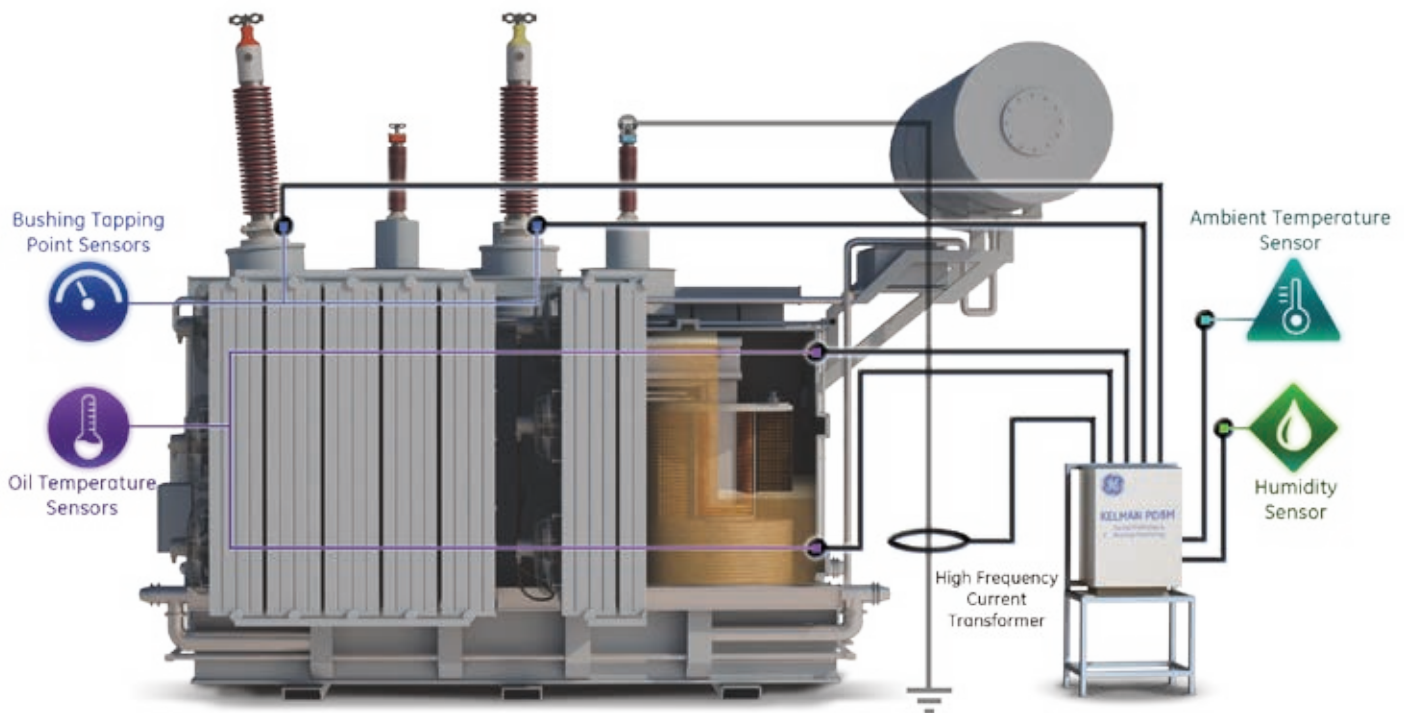Figure 2. Sum of Currents Measurement

Figure 3. Partial Discharge and Bushing Monitoring Sensor Overview

Partial Discharge Monitoring

Partial discharge appears as a high frequency signal superimposed on the power frequency signal from the bushing tap. There are several different ways of analysing this signal to eliminate external noise and to provide information about the amount, type, and location of partial discharge within the transformer.

The final solution chosen for this system was to include a GPS receiver in the system that can accurately timestamp all measurements and synchronise the measurements from three phase bushings and a high-frequency current transformer located on the neutral connection.

Sensors for transformer top oil temperature, ambient temperature and ambient humidity are also included to compensate the results to a reference. The arrangement of all sensors is shown in Figure 3.

The high frequency signal is digitized at 100MHz and all phases and neutral are sampled simultaneously to eliminate phase shift. This provides a resolution of 10ns. The time-of-flight for signals passing from phase terminations to neutral is calibrated during installation of the system, so discrimination between internally generated signals and external noise is possible.

USING A GPS RECEIVER, THE SYSTEM USES THE VERY PRECISE TIME SIGNALS TRANSMITTED BY THE GPS SATELLITES TO ACCURATELY TIMESTAMP AND SYNCHRONIZE ALL MEASUREMENTS.

PD Diagnostics and Interpretation

There are three levels of diagnostics and interpretation. The first level is the amplitude of PD pulses, and this can trigger an alarm within the software.

The second level is a Partial Discharge Activity (PDI) level, which combines the number of discharges and the amplitude to give an indication of the severity of any discharge within the transformer. The PDI value is provided as one of the outputs, which can be used to trigger and alarm, and can also be trended in the software along with the DGA values.

The third diagnostic level, which is not yet implemented, is to characterise the partial discharge according to Phase Resolved PD (PRPD) analysis. This is a common approach to characterising PD, determining the type of PD by the amplitude, position and decay of the high frequency pulses relative to the power frequency waveform.[7]

On-Site Experience

A partial discharge and bushing monitoring system was installed at Ballylumford Substation in Northern Ireland, on the coast, and connected to an existing TRANSFIX DGA monitor (Figure 4).

a) Transformer HV Bushings　　　　b) Monitoring System

Figure 4. Partial Discharge and Bushing Monitor Installed with TRANSFIX

Bushing Replacement

The customer had concerns about one of the bushings on this transformer and intended to change it with a spare bushing, in accordance with their maintenance policy. When the monitoring system was installed, there was no indication of any problem or deterioration in the bushing. There was no significant change in the sum-of-currents measurement, which was the system installed at that time (Figure 5).
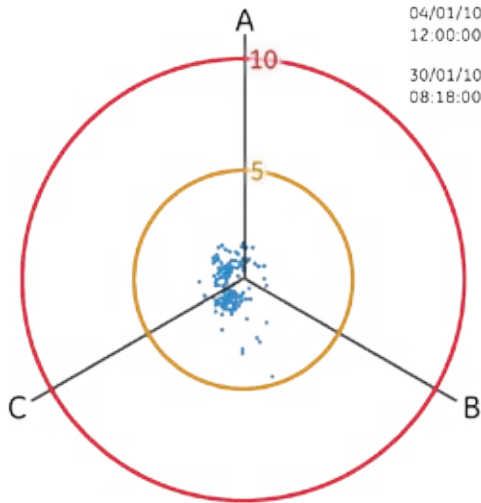

Figure 5. Sum of Currents Measurement

ALTHOUGH ONE BUSHING WAS THOUGHT TO BE DEFECTIVE BY THE CUSTOMER, THIS DID NOT TURN OUT TO BE THE CASE, AND THE NEED FOR REPLACEMENT WAS AVOIDED.

The customer changed the bushing, and during the transformer outage the monitoring system was changed to the system measuring relative parameters for individual bushings. Due to firmware problems, there was no data available from this system for several months. After the firmware bugs were fixed, data was received and again showed no problem with the replacement bushing (Figure 6).

It can be seen from Figure 6 (a) that the PDI figure varies between 0 and about 10,000 units. In this example, the activity on phases B and C is higher than the activity on phase A. Over time, the trend for each phase of a particular transformer can be plotted and alarm limits set at an appropriate value. As we gain more experience of the PDI values on different transformers, we will be able to recommend default alarm settings.

Phase Angle Comparisons

In Figure 6 (b), the phase angle measured between A-B and A-C does not change significantly – the variance is <0.3°. The leakage currents from the bushings are also constant, and there is a variance of about ±5% seen between the three phase bushings. Figure 6 (c).
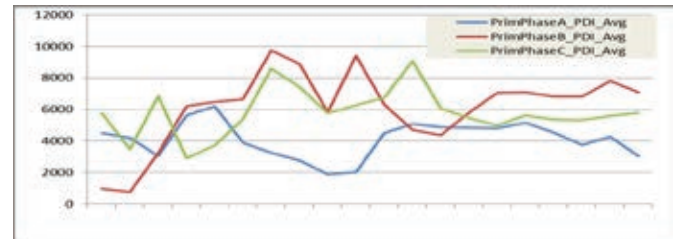
a) PDI Average Values (arbitrary units)
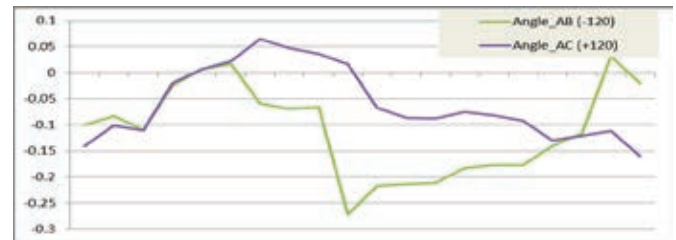
b) Phase Angle (normalised)
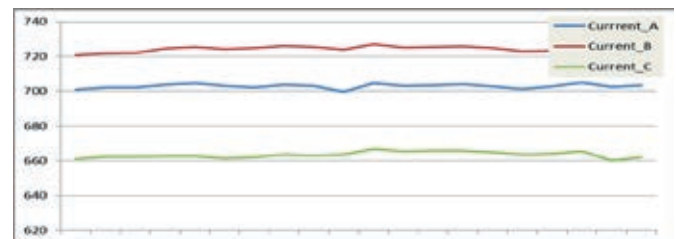
b) Leakage Current (mA)

Figure 6. Individual Bushing Parameter Measurement over 70 hour period

Bushing and Partial Discharge Monitoring

Over a period of several weeks, some strange phenomena were observed in the partial discharge measurements that could not be correlated to DGA activity or any known transformer issue. On further investigation, the only explanation was that this was some type of external noise that was being picked up by the monitoring system.

A local weather station was found that had meteorological data available for the relevant period, and the partial discharge signals were correlated with rainfall and wind (Figure 7). It was found that during periods of high wind and heavy rain the PD activity increased. The PD activity correlates well to high rainfall and high wind speed, although different phases are affected at different times, possibly due to the wind direction. It was assumed that this PD activity was due to external corona on the bushing porcelain surface because of the combination of wind, rain and salt-laden atmosphere.
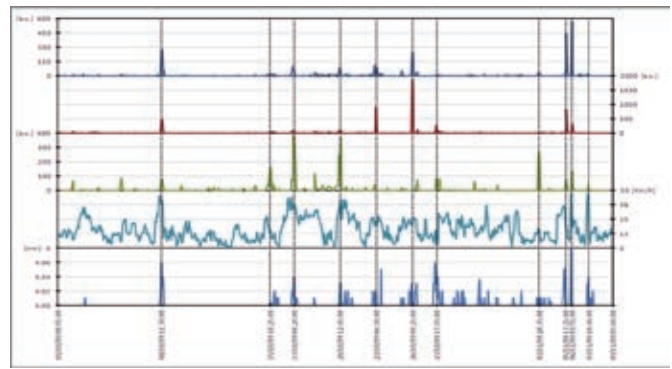
Figure 7. Partial Discharge Activity Correlated To Rainfall And Wind Speed

Most of the corona is filtered out of the system, but some remains, and under these circumstances it became the major contributor to the PD activity measurement. This has also been found to be the case in other studies, for both partial discharge and tgd activity[8]. The DGA measurements in the tank at this time indicated no partial discharge or other possible faults (Figure 8). All the hydrocarbon gases measured <5ppm and the hydrogen measured in the region of about 15ppm with a falling trend. This indicates that no gas was being generated in the transformer over this period, and that the hydrogen was being lost to atmosphere through the conservator.
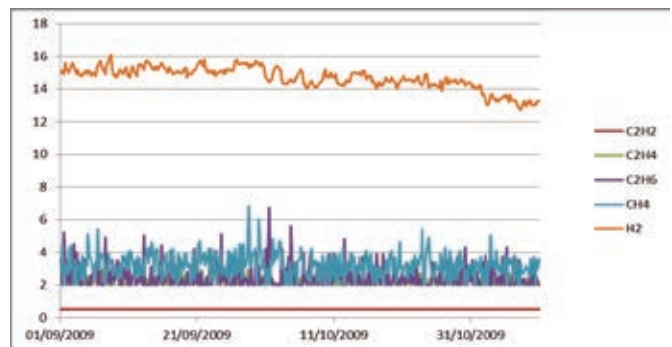
Figure 8. DGA values over the Same Period as Figure 7

One outcome of this investigation was the possibility of adding rain and wind sensors to the equipment in the future, perhaps as an optional extra, to help eliminate spurious signals due to the weather.

Further field trials of the system are planned for transformers that have known partial discharge and/or bushing problems, to gather more data and assess the effectiveness of the system for monitoring transformers.

PARTIAL DISCHARGE ACTIVITY ANALYSIS REQUIRES INTERPRETATION AND IS SUSCEPTIBLE TO ENVIRONMENTAL PHENOMENA. CORRELATION TO DGA RESULT HELPS ELIMINATE SPURIOUS CAUSES.

Conclusion

Measurements of partial discharge, bushing leakage current and bushing phase angle have been measured on a transformer along with the corresponding DGA measurements.

Although one bushing on the transformer was thought to be defective, this did not turn out to be the case, and no other issues were found to indicate any faults.

Heavy rainfall in conjunction with wind can give an indication of partial discharge, probably due to surface discharge on the bushings. This may be something that could be compensated for using wind and rain sensors, but it will require further development work. The DGA results corroborated the conclusion that there was no partial discharge within the tank.

The results of the trial have shown that the system can operate successfully and carry out the required measurements. Further investigation and trials are required to define meaningful limits for each of the measured parameters.

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dissolved gas analysis for power transformers

The use of extensive historical data, collected by laboratory analysis, allows for accurate fault detection and even fault prediction based on online Dissolved Gas Analysis (DGA).
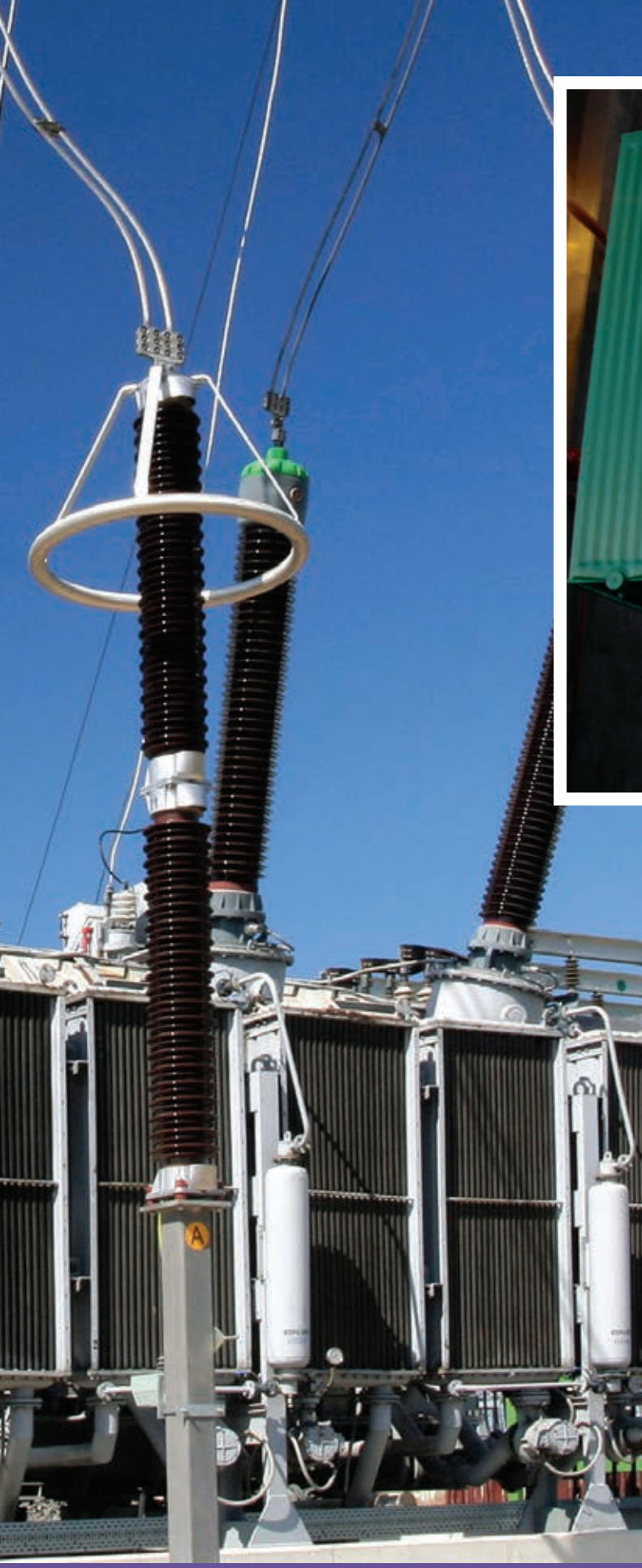
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Online management
of aging transformers using
PHOTO-ACOUSTIC SPECTROSCOPY

Dissolved Gas Analysis (DGA) is recognised as a powerful monitoring technique for the detection of developing faults within transformer main tanks and associated oil filled equipment.

Dissolved Gas Analysis for Power Transformers

Abstract

Dissolved Gas Analysis (DGA) is recognised as a powerful monitoring technique for the detection of developing faults within transformer main tanks and associated oil filled equipment. The use of extensive historical data, collected by laboratory analysis, allows for accurate fault detection and even fault prediction based on online DGA and this technique has become increasingly relevant with the ageing of the worldwide transformer fleet. Aspects of laboratory DGA are presented to illustrate the evolution from laboratory analysis to on-line DGA. The principles of Gas Chromatography (GC) are outlined together with an analysis of the difficulties associated with the use of this technology in field based on-line instrumentations. An introduction to Photo Acoustic Spectroscopy (PAS) technology employed for online monitoring is presented, together with a description of the significant benefits associated with using this robust technology for the challenging substation environment.

Abbreviations

PAS: Photo-Acoustic Spectroscopy   **GC:** Gas Chromatography

DGA: Dissolved Gas Analysis

Power transformers allow for the transmission of electrical power at efficiently high voltages and the subsequent use of this power at conveniently low voltages. Transformers have been used since the earliest days of electrical generation and transmission and have now become ubiquitous across the world – by some estimation there are greater than 2,000,000 large transformers worldwide (>100kVA). Although thousands of new transformers are being manufactured each year, the vast majority of transformers globally are already in operation and a significant proportion of those have already exceeded or are approaching the end of their design lifetime.

Virtually all large transformers, old or new, have cores and windings immersed in oil, together with input and output electrical connections. The transformer windings will normally be electrically insulated by thick layers of paper insulation wrapped around each part of each winding. The oil acts as both a heat dissipation and an insulating medium. When the oil or paper insulation is stressed, such as under elevated temperature conditions associated with high load and/or fault conditions or even under normal operating conditions, it will break down to form a range of by-products and simple gases. These gases dissolve into the oil immediately following their creation and will remain there indefinitely (if they cannot escape from the electrical equipment via a breather or a leak).
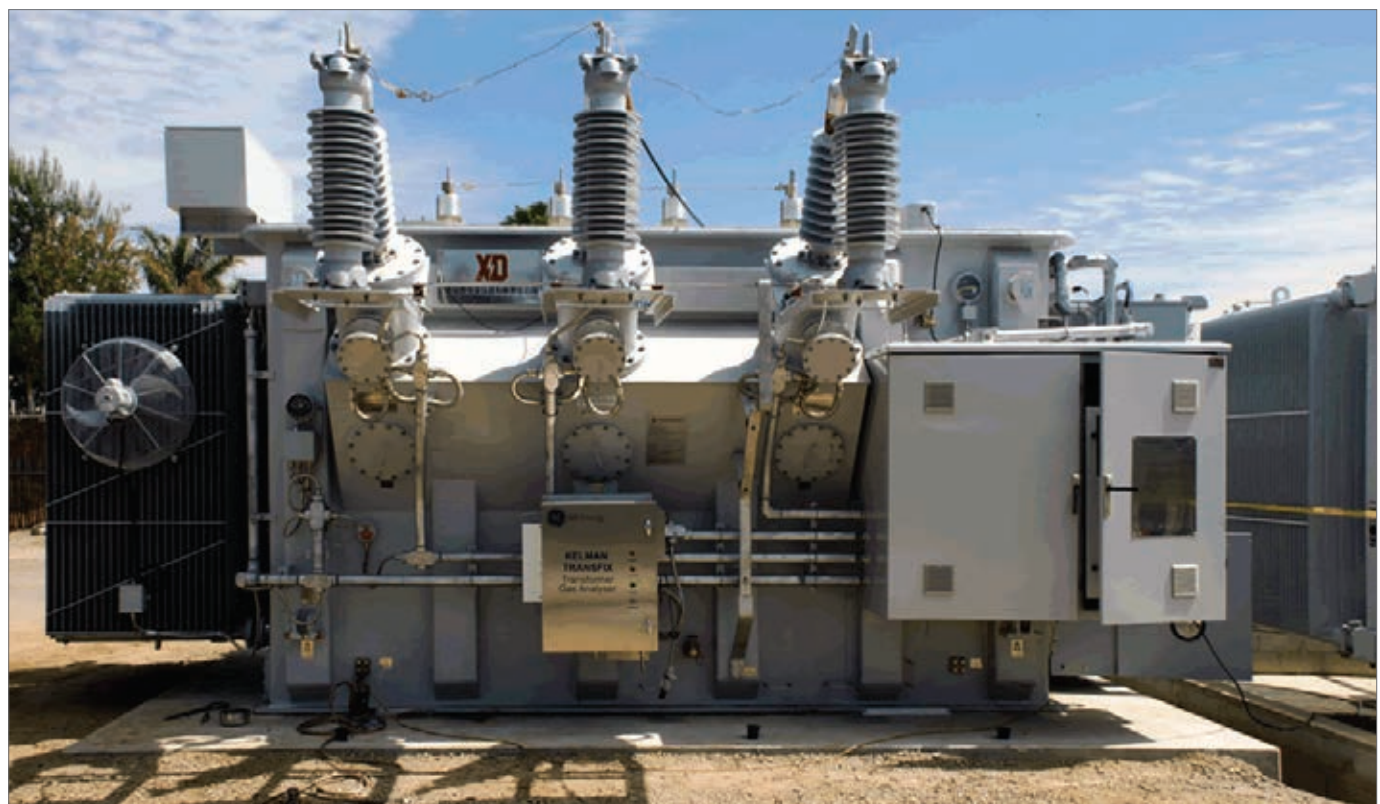
The gases that are associated with specific fault types are Hydrogen (H_2), Carbon Dioxide (CO_2), Carbon Monoxide (CO), Ethane (C_2H_6), Methane (CH_4), Ethylene (C_2H_4) and Acetylene (C_2H_2). They are known collectively as the diagnostic gases.

Analysis of the concentration of these diagnostic gases, called Dissolved Gas Analysis (DGA) has long been recognized as the single most powerful technique for transformer main tank fault detection / prediction. It has been at the forefront of most progressive utilities' monitoring strategy for the last four decades. This is evidenced by very many published papers and by numerous national and international standards relating to how DGA may be performed and how the results can be interpreted. With an aging and expanding transformer fleet and pressures to reduce both capital and operational expenditure, DGA has become even more important to utilities and industries. This trend is set to continue as the global fleet ages and the pressure on utilities to compete intensifies.

Manual Samples and Laboratory DGA

Traditionally DGA was limited to a laboratory test because of the complexity of the equipment required to extract and measure gases at quantities as low as one part-per-million (ppm).

Historically gas extraction was normally performed using a strong vacuum pump for degassing a sample of the oil prior to analysis – called a Toepler pump apparatus. More recently, IEC, ASTM and others have published methods describing a gas extraction technique that is suitable for automation. "Headspace Gas Extraction" is now becoming the most common technique employed in laboratories due to its convenience and excellent repeatability at the gas extraction stage of the process.
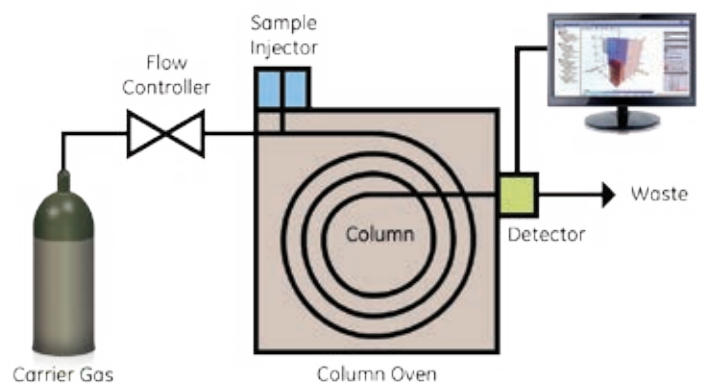
Figure 1. Basic diagram of a Gas Chromatogram showing the major components that go into making such a system. A DGA specified GC will in addition to these basic components require two columns and two detectors to get the required level of sensitivity.

The gas detection technology utilized in the laboratory is based around the separation of each gas in a gas mixture. This is achieved by introducing the gas mix to be analyzed into a constant stream of a "carrier gas" and from there, subsequent detection of the gas on one of several detectors. Called Gas Chromatography (GC) this technique can be designed to be sensitive to each target gas and in fact, can be used to analyze a huge variety of diverse types of samples from oil and gas to water and air pollution.

Each GC is set up for a specific application. A specific carrier gas is chosen to drive the gas sample from its injection point down the length of the column where it will separate as the more mobile molecules in the mixture travel faster. This technique requires very tight control of gas flow rates, temperatures and carrier gas quality. It is a sensitive but unstable technique which has historically been confined to a laboratory environment. This is primarily because GC is sensitive to changing local conditions, e.g. temperature, pressure, movement, continuity of gas flow rates etc. As a result of this high degree of sensitivity to environmental factors, GC requires daily recalibration for continued quality operation. It is for this reason that this technique has remained the exclusive preserve of the laboratory environment for most of the last 50 years. Initial attempts to utilize GC in the field environment have met with limited success - with the single biggest problem being equipment drift, leading to poor repeatability of results from one sample to the next.

KELMAN TRANSFIX AND THE APPLICATION OF PAS TO ONLINE DGA IS A SIGNIFICANT LEAP FORWARD IN THE FIELD OF AUTONOMOUS, STABLE AND ROBUST ONLINE MONITORING.

With laboratory DGA, oil testing has usually been limited to an annual process. Typically a substation operator would collect a sample of oil into a syringe or bottle, note nameplate information, oil temperatures and other details relating to the transformer, package the sample and ship it to the laboratory. Due to the costs involved (site visit, logistics and laboratory analysis), sampling and analysis would usually be restricted to once per year, with repeated or more frequent samples collected and tested only if significant fault gases were detected in the routine annual sample. As many types of faults can progress significantly in less than one year, this approach often resulted in missed diagnostic opportunities. Faults could occur and progress for up to 12 months before being detected and significant damage caused to the transformer in the mean-time as a result. For this reason, in recent years there has been a dramatic increase in technology companies supplying instrumentation for online, automated DGA on a frequency up to one sample per hour.

On-line, Remote DGA

Recent advances in gas detection technology have seen DGA move out of the laboratory and into the field for the first time. Starting with composite gas detectors capable of passively sampling fault gases through a membrane, (the GE HYDRAN™ - now a byword for transformer monitoring is one such equipment), online DGA has advanced to a point where full, 9 gas analysis can now be performed many times a day according to a pre-programmed schedule, without any user intervention required. Providing unprecedented levels of information, these devices add a whole new dimension to the field of fault detection. By adding communication to the monitoring units, users can remotely track daily, weekly and seasonal gassing trends. These essentially real-time results can be used, not only to detect active faults but even to predict the development of a fault before it becomes a real service issue.

Originally, on-line monitoring devices were based on simple versions of laboratory Gas Chromatography (GC) equipment, packaged in a way so as to allow them to work in a field environment. Accuracy had to be sacrificed for cost and automatic operation purposes (a laboratory GC costs as much as US$100,000!). As these systems have evolved (and stability of GC in the field has been drawn into question), a new technology has emerged to challenge the previously prevalent GC. Developed specifically to address the shortcomings of online GC: Photo Acoustic Spectroscopy (PAS) based DGA instruments entered the market in 2002. Utilizing detection technology normally associated with urban pollution monitoring, PAS based systems have, by 2012, become one of the most trusted technologies for online and portable DGA applications. As such PAS based instruments now have the largest install base of any competing product range worldwide.

GE offers such PAS based monitoring units (in the form of its Kelman TRANSFIX™ range of on-line monitors) and believes that these PAS instruments offer significant advantages over GC technology based units. TRANSFIX is capable of collecting and extracting all diagnostic gases according to the standard principles of headspace extraction and analyzing them at concentrations as low as 0.5ppm. Quantification of the full range of diagnostic gases with a precision and accuracy similar to a laboratory is now possible online on an hourly basis without need for recalibration, consumables or frequent servicing.

PAS Technology

PAS is an old science and was first observed by Alexander Graham Bell in 1880 using the sun as an IR source and the human ear as the detector of the acoustic signal. In the 1970s, with the emergence of modern electronics, interest was renewed in this science since the technique offered a very sensitive method for the identification and quantification of trace amounts of atmospheric gas pollutants without the need for regular recalibration of the detector.

Photo Acoustic Spectroscopy (PAS) works along the following principle: A substance absorbs light energy and converts it to sound energy. The absorbed energy from the light is transformed into local heating and kinetic energy of the sample by the energy exchange processes. This kinetic energy and associated heating results in a pressure wave (sound) that can be picked up by a microphone. By pulsating the light source, repeated measurements can be made on a single sample. A photo acoustic spectrum of a sample can be recorded by measuring the sound intensity at different wavelengths, produced with a combination of a broadband IR source and a diffraction grating . This spectrum can be used to identify the absorbing components of the sample. Photo acoustic spectroscopy has become a powerful technique to study concentrations of gases at the part per billion levels. Modern photo-acoustic detectors still rely on the same principles as Bell's apparatus, however to increase the sensitivity the following modifications have been made:

1. Use of intense IR sources or lasers to excite the sample, since the intensity of the generated sound is proportional to the IR energy intensity (and the gas concentration).

2. The ear has been replaced by sensitive microphones. The microphone signals are further amplified and detected using lock-in amplifiers.

3. By enclosing the gaseous sample in a cylindrical chamber, the sound signal is amplified by tuning the modulation frequency to an acoustic resonance of the sample cell.

In the GE photo-acoustic detector, broadband IR is produced by a black body IR source. IR filters are used to select regions of the infrared spectrum that overlap with particular target gas species. This allows for multiple gas species to be detected without the expense and complexity of multiple lasers while still achieving parts per million gas detection levels.

PAS for DGA

Utilizing a PAS based analyzer for quantification of the transformer fault gases, GE has avoided many of the issues associated with employing a GC for this field application.

Advantages of using PAS over the GC style technology are:

a) Less sensitivity to the environment.

GC systems are very sensitive to environmental conditions (temp, humidity, atmospheric pressure, movement associated with vibration or wind buffeting etc.). While these conditions are perfectly controlled and checked in a laboratory, in the field this is much more challenging, with systems having to cope with day to night changes, winter to summer changes, weather patterns and local shaking from transformer vibration, road traffic and industrial processes. To provide a suitable environment for a field based GC system is costly and complex, but this is the only way to guarantee long term accurate results from a GC based DGA system. Great care must be taken by the utility when assessing the guaranteed specification of operating conditions for the GC system in the field. This is often overlooked by the manufacturer in instrument specifications and only become obvious upon extended operation of the field GC. In contrast, a PAS system is virtually immune to environmental conditions such as temperature, noise and vibration and remains accurate over a very wide range of operating conditions and long duration.

b) No requirement for regular recalibration.

Laboratory based GC systems need to be recalibrated once per day according to recommendation laid out in IEC standard relating to DGA, because they are very sensitive to a range of elements: environmental as discussed above, but also column ageing (which affects the time it takes for the sample to traverse the length of the column, a value which must be known with absolute certainty for qualification and quantification of each gas). While this is possible in a laboratory environment where systems can be maintained with high levels of stability, the same is difficult in the field and so results can vary constantly in a field based system. To perform frequent recalibration, GC systems need a bottle of calibration gas. The more gas they use, the larger the bottle needed or the more often it needs to be replaced. Less calibration gas usage means less frequent recalibration and potentially less accurate results. If the field GC has a suitable supply of calibration gas it must still be calibrated every few days to avoid major drift problems. This constant recalibration gives a discontinuous set of results over time because batches of results are measured off a different recalibrated set-point. This leads to discontinuity in trending charts and makes modeling of trends difficult. To combat this, manufacturers often include an internal smoothing/averaging algorithm to mask these discontinuities but this reduces the sensitivity of the system and provides for the possibility that a real electrical fault will be "smoothed" out in the results displayed for several days. In contrast, PAS systems only need to be recalibrated every 5 years or 10,000 measurements. This means that all measurements, year after year are based on the same calibration set-point. This leads to a more precise instrument that detects minute changes. Because smoothing is not applied to PAS

based measurements, normal operating transformer results may appear slightly noisy but in fact the results better reflect the actual changing conditions within the transformer.

c) No requirement for multipoint recalibration in the field.

IEC standards relating to DGA state that a GC system employed for DGA must be calibrated at several different concentrations as the detectors used in GC systems are known to be non-linear in their response over a broad range of concentrations. While common in laboratories where high accuracy is required, no current model of field based GC has this capability. PAS based instruments produce a linear response to changing gas concentrations over a huge range - from approximately 1 ppm to over 30,000 ppm, gas-in-oil.

d) No carrier gases to be connected up, replaced when exhausted or managed in stock.

PAS technology uses atmospheric air as its carrier medium and is immune to changing atmospheric air content for outdoor ambient air. PAS systems measure the background air prior to a gas-in-oil measurement and subtract any effect of this air from the final measurement. By contrast GC systems usually require very high purity (99.999% purity) Argon (use in labs) or Helium (used in field systems due to its lower cost) to operate with good stability. Failure to use these high purity gases in a GC can drastically reduce the lifetime of the column and cause damage to the detectors. As a further benefit, PAS based systems do not require any account keeping about gas usage or logistics surrounding planning gas bottle replacement or delivering them to site in a timely manner and installing them.

e) No safety implications

Use of PAS for DGA avoids the safety implications associated with using and storing potentially hazardous high pressure gas cylinders (hydrogen and calibration gas mixtures required by GCs) beside the instrument in the substation. Also it should be noted that a GC based system operates one of its detectors by maintaining a lit hydrogen flame. This can have obvious safety implication in some environments. Some systems on in the market omit the detector based on a Hydrogen flame and sacrifice some accuracy by doing so.

f) No columns to replace at regular interval

To maintain the levels of accuracy and precision that is possible with a new GC column, replacement is required up to every six months, making this the default service interval (assuming the cylinders of gas are large enough to last at least 6 months). This has to be taken into account over the life of the equipment as 8-gas GC systems use 2 different columns and column replacement is a difficult process normally requiring a specifically trained commissioning engineer. Systems employing only a single column invariable suffer a loss of selectivity in gas measurement associated with using only one column.

The above are just some of the issues associated with using what is essentially a laboratory technology in the field and are the main reasons that GE has developed a system that utilizes PAS gas detection as a preferred alternative for field application. As stated, although the above issues are easy to manage in a laboratory environment where a GC system will be serviced by a technician on a daily basis, they become significant for a

system which needs to operate autonomously over long periods of time. Indeed for a technology that requires daily attention in a controlled laboratory environment, a field GC may reasonably be expected to require service visits more often than the transformer or associated substation equipment. Where a primary benefit of online DGA is a reduction in operation expenditure associated with routine scheduled transformer maintenance, the monitoring device should logically require less frequent service visit than the transformer itself.

The TRANSFIX has a default service interval of 5 years (and up to 10 years depending on mode of operation) and this is much more appropriate to a substation environment.

As a result of the above issues TRANSFIX and the application of PAS to online DGA is a significant leap forward in the field of autonomous, stable and robust online monitoring. With the inclusion of a Hydrogen sensor, an Oxygen sensor and a moisture sensor TRANSFIX can perform regular full DGA online, offering as a real practical alternative to laboratory DGA testing.

PAS BASED DGA INSTRUMENTS HAVE BEEN DEVELOPED WITH THE EXPRESS PURPOSE OF ADDRESSING THE SHORTCOMINGS OF ONLINE GC BASED INSTRUMENTS.

Accuracy versus Precision

To discuss the subject of accuracy and precision for online DGA, we first need to start with a couple of definitions:

"Accuracy" is how close a measured value is to the actual (true) value while

"Precision" is how close the measured values are to each other.

These are well illustrated by the following diagrams:

Low Accuracy
High Precision

High Accuracy
Low Precision

High Accuracy
High Precision
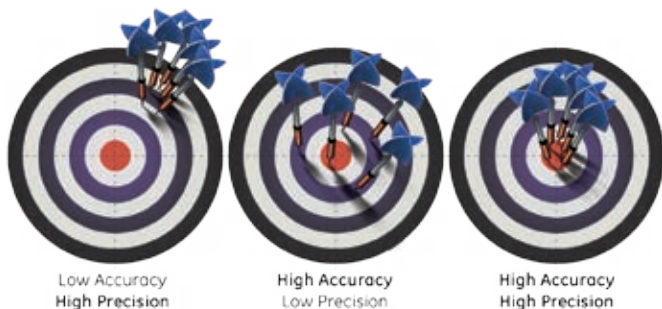
The diagnostic algorithms for DGA are focused to a large extent on trending changes in gas levels within the transformer rather than absolute quantities of gas-in-oil. For example, a quantity of 100 ppm of ethylene in a transformer main tank may not be of concern if it is known to have been created by a fault in the transformer which has now been repaired. However a quantity of ethylene increasing by 100 ppm over a period of time (weeks or months) probably indicates a serious fault which requires immediate attention. Thus changes and the rate of these changes are more important in DGA results analysis than absolute quantities.

In order to only detect real changes and have meaningful rate of change calculations, the key requirement in DGA is for the unit to be "precise". This is more critical than "accuracy" because an accurate but imprecise system will have poor repeatability and give you variation in the results (indicating changes) when there is really no change. GE has designed TRANSFIX with "precision" as the primary performance characteristic: the ability to have a repeatable value for repeated measurements of the same oil sample. TRANSFIX is capable of precision far in excess of what manual sampling and laboratory testing can achieve.

Clearly accuracy is also useful and TRANSFIX has been developed as a whole analytical system, capable of oil sampling, gas extraction and gas detection. Absolute accuracy of the detector is established by calibration to gas standards with full traceability to international physical standards. During manufacture, standard gas-in-oil samples are prepared and cross instrument verification is used to verify the product's accuracy.

TRANSFIX, a GE product based on PAS technology, is a stable, accurate and very precise instrument capable of autonomous operation over long periods of time without any requirement for consumables. This is a significant advancement in the field of online DGA and offers flexibility of operation not seen before.

Kelman TRANSFIX

Features and Benefits

The TRANSFIX incorporates the following features into its basic architecture:

Full online fault gas DGA using PAS with additional sensors used to provide values for O_2, N_2 and moisture in oil.

Detection of the critical gas acetylene at an impressive 0.5 ppm. Most other diagnostic gases are detected at the recommended 1 ppm.

Load current and ambient temperature recording and tracking to correlate with gas production rates.

Autonomous operation with only oil filters possibly requiring replacement depending on particulate matter loading of the oil.

Multiple alarm relays - programmable caution and alarm options.

Quantitative gas levels and rate of change alarm capability.

Multiple remote communications options.

Multiple communication protocols available.

Wide range of operational environments

- 0 - 2000m altitude.
- -40 ° C to +55 ° C ambient temperature.

The PAS technology and GE's unique approach to online DGA provides the following benefits to the user.

The instrument requires no consumables over a 5 year service interval

- No or very low operational expenditure.

- 5 year interval for service visits.

Stable and repeatable results provided due to the resistance of the detector to drift.

Highly accurate detector, established by calibration to internationally traceable physical standards.

Results and diagnosis of fault conditions available 24/7 via a suite of software capable of collecting and collating data from multiple online units.

Long life, > 15 years is typical.

Full cycle of analysis completed in as little as one hour and at a programmable interval anywhere between 1 hour and 4 weeks.

Interval can be set to automatically increase when caution alarm level has been reached.

Turnkey solutions available to suit individual application requirements.

Additional Benefits of PAS Technology

In addition to the many benefits already discussed, PAS technology has two further unique features that sets it apart from all the competitors for DGA gas detection.

Chief among these is the ability of the PAS detector to transition from measuring very low concentration sample, with just a few ppm of gas-in-oil, to very high concentration samples with

>30,000 ppm gas-in-oil and then back again, without any carryover or fatigue of the detector. This is of particular importance for transformer on-load tap changer (OLTC) monitoring. Analysis has shown that excepting bushing failure, the most common transformer failure mechanism is tap changer failure. Although failure within the main tank can spell the end of life for the transformer and must be guarded against with DGA monitoring, the reality is that over the life of the transformer it is more likely that the tap changer will fail unexpectedly. On critical transformers incorporating an OLTC the tap changer unit needs to be monitored to detect these developing faults.

PAS detectors are perfect for this application. With PAS there is no retention of gases from one analysis to the next and measured gases are simply flushed from the system in an air stream following analysis: all internal surfaces that the gas may come into contact are inert (PTFE, glass, gold and stainless steel) and so there is no gas retention of any sort. On the other hand, using GC based instrumentation for monitoring the main tank and the tap changer would require 2 separate instruments. This is because GC cannot step from low, to high, to low concentration gas-in-oil samples. A GC column is designed to retain gas and only releases it with forced carrier gas and elevated temperature and this feature precludes an application where high concentrations need to be followed by low concentrations.

Finally, and of most significance to portable instrument application, photo acoustic spectroscopy allows for engineering of physically robust instrumentation. PAS systems are extremely rugged and are insensitive to day-to-day mechanical shock and vibration. They are also small and do not require careful temperature control. This allows for the possibility of a small, light, portable DGA instrument suited to transportation, unpackaged, in a maintenance truck with other substation tools and equipment. As a comparison GC requires very careful transportation and is sensitive to all movement, requiring recalibration every time it is moved to a new location.

GE PAS Based Instruments

In addition to the TRANSFIX, GE manufactures a range of DGA equipment to meet all requirements and applications of field DGA. These are:

Kelman TRANSFIX™

Full 9 gas main tank online DGA + H_2O using Photo Acoustic Spectroscopy (PAS) technology.

Kelman TAPTRANS™

Full 9 gas multiple oil sources DGA + H_2O. This product is unique in its ability to sequentially analyse a sample of oil from the main tank as well as from the diverter and selector tanks of the OLTC while avoiding gas or oil carryover from high to low gas in oil sources. This is achieved by the use of two separate oil handing systems built within a single instrument and the fact the PAS systems are immune to gas carry-over. This product is ideally suited to large critical transformers incorporating an OLTC.

Kelman MULTITRANS™

Full 9 gas DGA + H_2O sampling oil from up to three main tanks sequentially. This product is designed for situations where three separate tanks are in the same 3 phase transformer or where three single phase transformers are all within a 50m radius.

Kelman MINITRANS™

This low cost online 3 gases + H_2O device provides many of the benefits associated with the premium Transfix but at a fraction of the cost. MINITRANS is best suited to general deployment in large numbers among smaller or less critical transformers.

Kelman TRANSPORT X™

Full diagnostic gas + H_2O in a self-contained and fully portable robust instrument. Capable of performing a DGA analysis with diagnostics in under ½ hour. Best suited to situations where online DGA is not in place or where quick analysis is required following a single gas online DGA alarm.

Conclusion

PAS based DGA instruments have been developed with the express purpose of addressing the shortcomings of online GC based instruments. They provide a real alternative to GC by employing technology much more suited to long term autonomous operation. Requiring no consumable gases or frequent designed service intervals, the TRANSFIX family of products has revolutionised the landscape of multigas online DGA. Just 10 years after its launch, TRANSFIX has the largest installed base of any multi-gas DGA instrument worldwide.

TRANSFIX provides for monitoring of all the diagnostic gases together with O_2, N_2 and H_2O. By monitoring these parameters up to once per hour while correlating to load and temperature, the amount of data available for trending, analysis and diagnostics is second-to-none. Utilising a technology specifically designed for online application, GE manufactures a very stable and repeatable monitoring instrument perfectly suited for the tough environmental and operational demands often associated with remote substation operation. It has become the new high-end standard for monitoring critical transformers.

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ONLINE MANAGEMENT OF AGING TRANSFORMERS USING PHOTO-ACOUSTIC SPECTROSCOPY

distribution automation

This paper presents a new Distributed Bus Protection System that represents
a step forward in the concept of a Smart Substation solution.
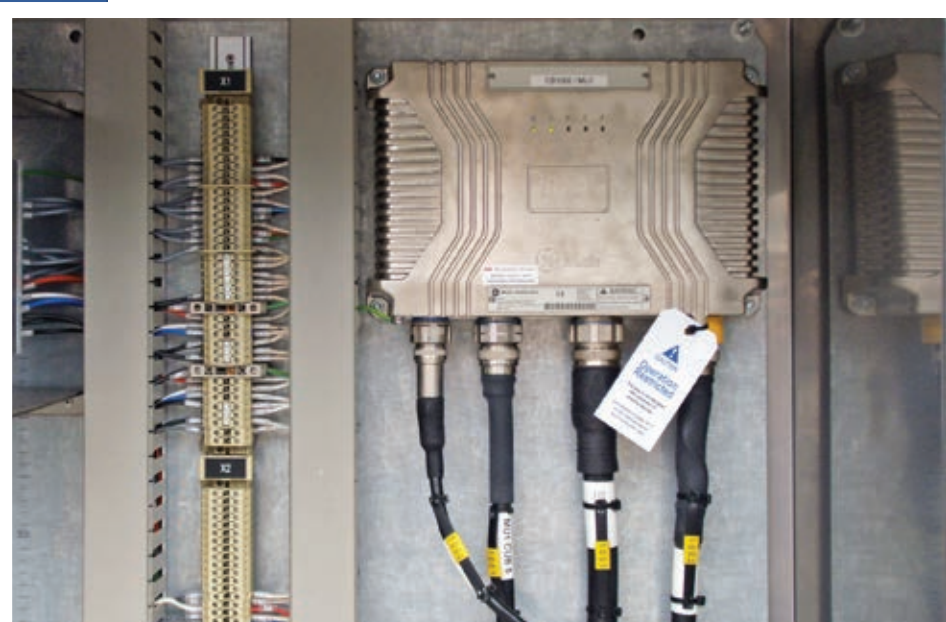
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Richard Hunt, GE Digital Energy

Distributed bus protection application

in a platform for process bus deployment in the

SMART SUBSTATION

Bus protection is typically a station-wide protection function, as it uses the majority of the high voltage (HV) electrical signals available in a substation.

Abstract

Bus protection is typically a station-wide protection function, as it uses the majority of the high voltage (HV) electrical signals available in a substation. All current measurements that define the bus zone of protection are needed. Voltages may be included in bus protection relays, as the number of voltages is relatively low, so little additional investment is not needed to integrate them into the protection system.

This special circumstance, where all HV electrical signals are connected to a single device, allows defining a bus protection scheme as the basic structure for the implementation of a complete Protection, Control and Monitoring System in a HV Substation.

Bus protection is not presently defined as a complete Protection, Control and Monitoring System due to the challenges of data collection. All HV electrical signals, equipment status signals, and equipment control signals, must be physically wired to the bus protection system, and must be further wired to other devices for other zones of protection. Distributed bus protection was developed to partially address this challenge of data collection. Bay units are installed in individual line bays to simplify the field wiring necessary for data collection by collecting the HV electrical signals, equipment status signals, and equipment control signals locally. However, the bay units are still dedicated to a single zone of protection, that of bus protection and the bay units are wired in conjunction with other devices.

This paper presents a new Distributed Bus Protection System that represents a step forward in the concept of a Smart Substation solution. This Distributed Bus Protection System has been conceived not only as a protection system, but as a platform that incorporates the data collection from the HV equipment in an IEC 61850 process bus scheme. This new bus protection system is still a distributed bus protection solution. As opposed to dedicated bay units, this system uses IEC 61850 process interface units (that combine both merging units and contact I/O) for data collection.

The main advantage then, is that as the bus protection is deployed, it is also deploying the platform to do data collection for other protection, control, and monitoring functions needed in the substation, such as line, transformer, and feeder. By installing the data collection pieces, this provides for the simplification of engineering tasks, and substantial savings in wiring, number of components, cabinets, installation, and commissioning. In this way the new bus protection system is the gateway to process bus, as opposed to an add-on to a process bus system. The paper analyzes and describes the new Bus Protection System as a new conceptual design for a Smart Substation, highlighting the advantages in a vision that comprises not only a single element, but the entire installation.

Busbar Protection Operating Principle

Khirchoff's current law states that the sum of the currents entering a given node must be equal to the currents leaving that node. It applies to ac current for instantaneous values. Thus, the sum of the currents in all feeders of a busbar plus any bus fault current must be zero at any instant in time. The sum of the feeder currents alone therefore equals the bus fault current.

Consider the two situations demonstrated for the simple bus shown in Figure 1.

In case of an external fault, the current leaving the bus is equal to the sum of all of the currents entering the bus, and the total summation is zero. The same would be true when considering load flow. On the other hand, in case of an internal fault, the sum of all of the currents entering the bus is equal to the total fault current (summation of feeder currents is not zero). An ideal differential relaying system takes advantage of the fact that the sum of the feeder currents will be zero for external faults or load flow, whereas the sum will be equal to the total fault current for internal faults. Unfortunately, there are problems introduced wherein the ideal cannot always be obtained, and steps must be taken to insure that the differential relaying system works properly, even under non-ideal conditions.

Low Impedance Current Differential

It is possible to use a low impedance device in the differential circuit if steps are taken to overcome the effects of feeder current measurement errors such as CT saturation. Consider the situation shown in Figure 2, which develops a so called restraint quantity to mitigate against measurement errors.

The currents are shown in oversimplified form and are meant for demonstration purposes only. The CT in Line 2 is assumed to saturate completely every half cycle so that the current Ix will be as shown. As a result of the collapse of the CT in Line 2, the differential current Id will flow. The operating current, Iop, is the absolute value of the differential current Id and the restraining current, Irest. Irest can take various values such as the maximum of all currents entering and leaving the busbar, the sum of the absolute values of all of the currents entering and leaving the busbar, etc. The key point to note in this Figure is that the restraint current is significant during the period of nonsaturation while the operating current at the same time is equal to or very nearly equal to zero.
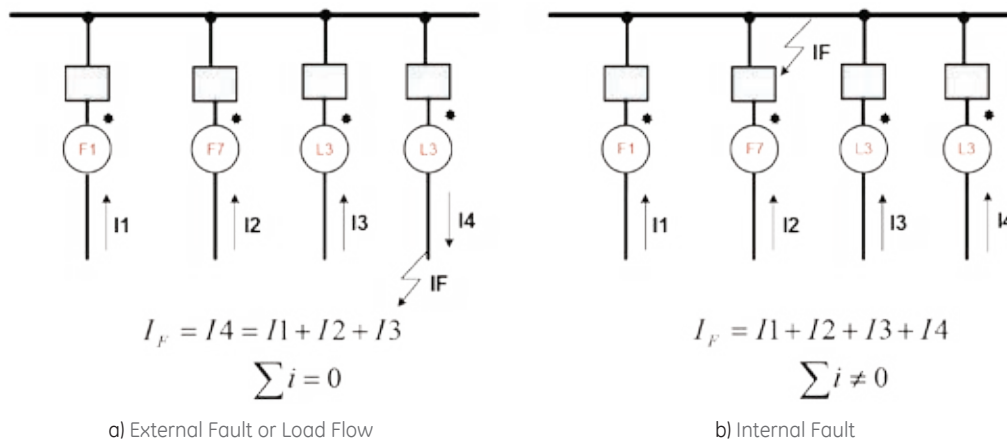

$$I_F = I4 = I1 + I2 + I3$$
$$\sum i = 0$$

a) External Fault or Load Flow

$$I_F = I1 + I2 + I3 + I4$$
$$\sum i \neq 0$$

b) Internal Fault

Figure 1. Simple Bus Arrangement

$$R_r = 2 * RL + Rct$$
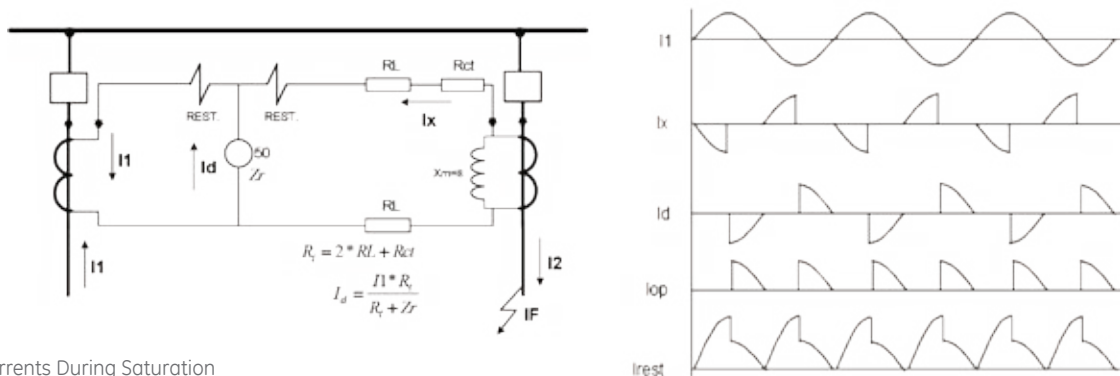$$I_d = \frac{I1 * R_r}{R_r + Zr}$$

Figure 2. Currents During Saturation

The relay shown in Figure 3 takes advantage of this condition to prevent operation during external faults with significant saturation in the fault CT, but to allow operation during internal faults without any delay. High speed operation, in less than one cycle, can be obtained for heavy faults. The current differential element shown in Figure 3 is in effect a percentage restrained overcurrent relay; i.e., the differential element (4) produces an output when the operating current (Iop) exceeds Kr percent of the restraining current (5).

This relay also requires that all of the CT leads be brought into the relay house for connection to the relay. Additionally there is a directional element (10) that is used to supervise the tripping of the differential unit in case of CT saturation

The directional principle (block 10) checks if the currents of significant magnitudes (as compared with the fault current):

- flow in one direction (internal fault) or,

- one of them flows in the opposite direction as compared with the sum of the remaining currents (external fault).

The directional check should be performed only for the currents that are fault current "contributors" (in contrary to load currents).

Most Common Bus Arrangements

A power system bus is, at the most basic, an interconnection of circuits. Protection of a bus is straightforward, and uses any number of protection methods, including the low impedance differential method as described. The challenge to bus protection is actually in power system operations. Different busbar configurations have been developed to support redirection and reconfiguration of power system flows, to support maintenance activities, to allow efficient use of physical space, and to reduce the amount of capital equipment required. Bus protection on any type must be suitable for all typical bus arrangements.
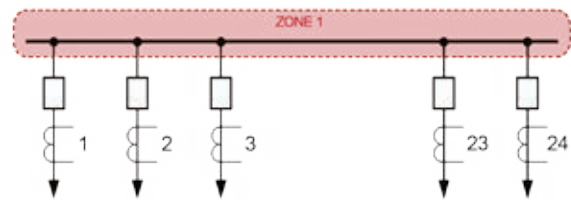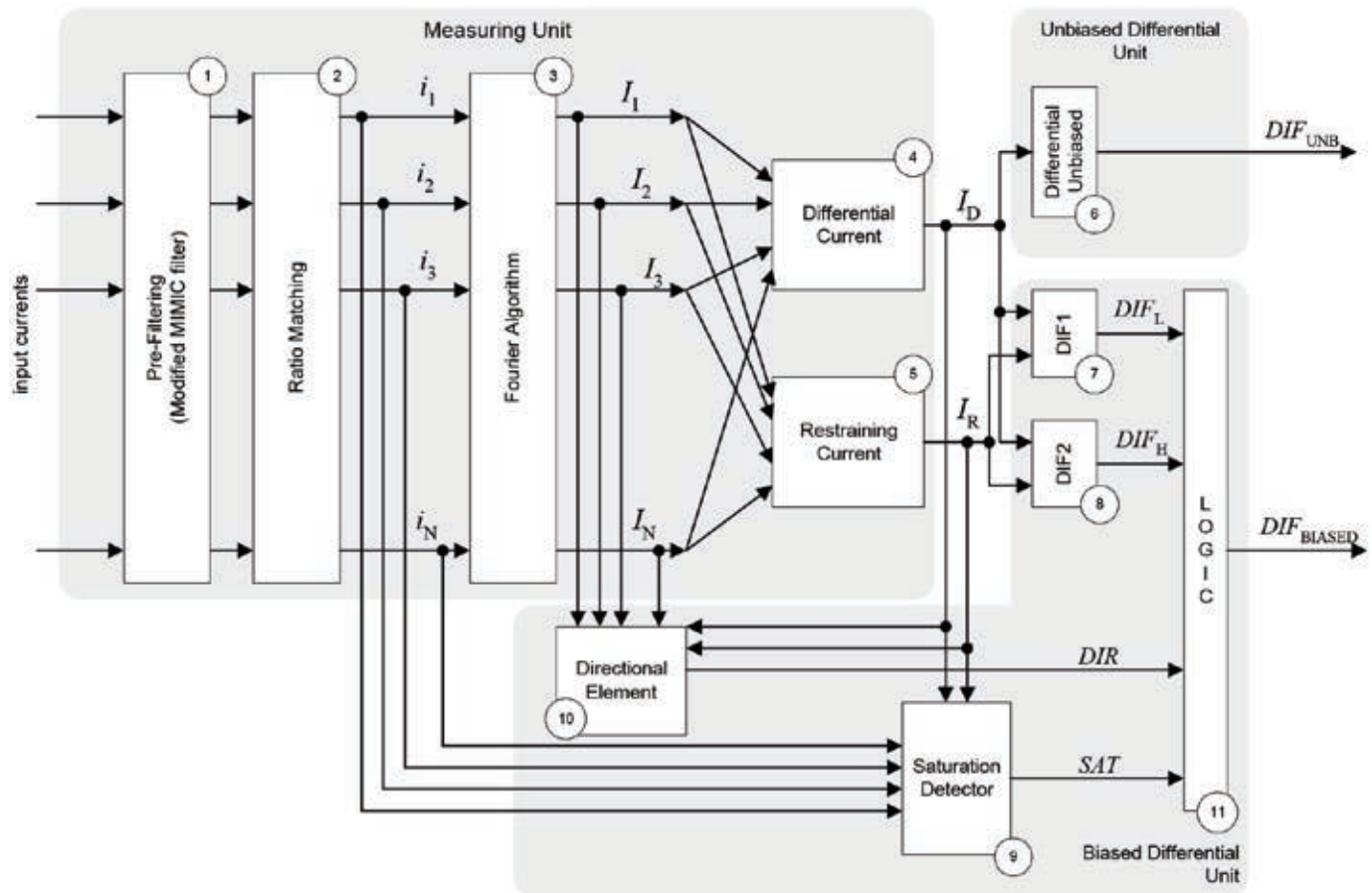

Figure 4. Single Busbar System

Figure 3. Low Impedance Current Differential with Directional current element as second criteria for ripping and CT Saturation Detection to control the trip logic.

The most common and simple Bus arrangement is the single busbar. See Figure 4.

In some bus arrangements, it is common to switch lines to different buses in the substation to facilitate operation and/or maintenance. The most common in this case is the double busbar system. See Figure 5.
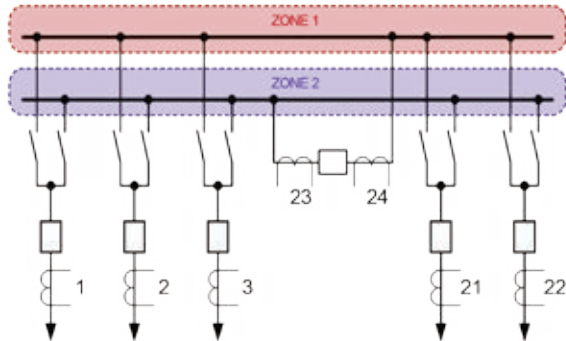

Figure 5. Double Busbar System

There are some variants where a transfer bus is included. A double and transfer bus system is shown in Figure 6. In this arrangement, the tie breaker is connected to one of the lines through the transfer bus while the regular line breaker is removed from service. The switching of the breakers is accomplished via the line switches associated with the breaker to be switched. In the low impedance differential relay described above, auxiliary switches (a and b) associated with the line switches (and certain breakers in some arrangements) are brought into the relay and the state of these switches is used by the relay to determine which breakers are connected to which bus so that the correct differential zones can be established. The CT's in this situation are always connected to the relay, thus CT switching is not required, because the determination of the zone of protection is done via software in the relay. Separate trip outputs are provided for each breaker thus only those breakers associated with the faulted bus will be tripped at the time of a bus fault (one relay can protect multiple buses).
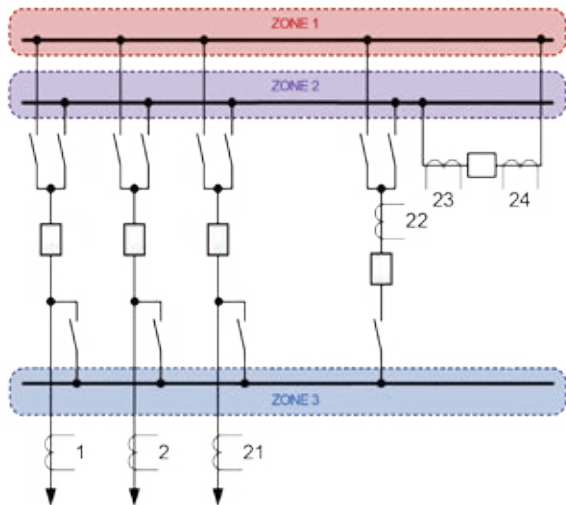

Figure 6. Double and Transfer Bus System

Another version of the double busbar arrangement is shown in Figure 7, where each busbar segment is split into 2 segments through the use of a tie breaker.
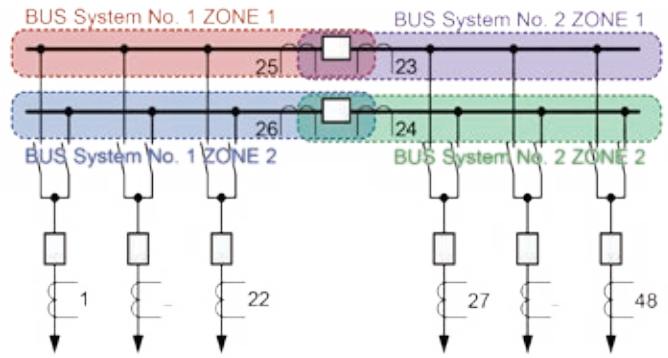

Figure 7. Two Double BusBar System

A configuration that is very popular for HV substations is the breaker-and-a-half arrangement. Breaker-and-a-half provides similar operating advantages to double busbar, but requires fewer circuit breakers and isolator switches. For busbar protection purposes the breaker-and-a-half is equivalent to a two single busbar systems.
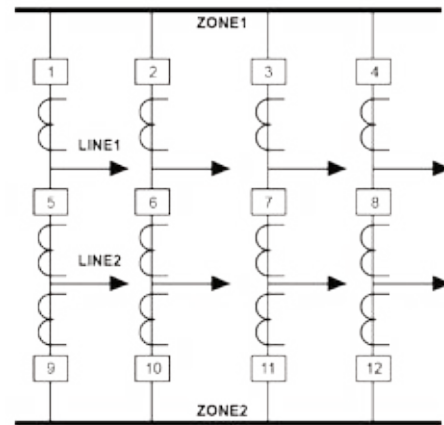

Figure 8. Breaker-and-a-half arrangement

Another configuration very popular in the USA is the double busbar with by-pass. In this mode the operation is in single bus. The other bus is used for a line where the feeder is bypassed for maintenance, and the bus coupler breaker becomes the line breaker. See Figure 9.
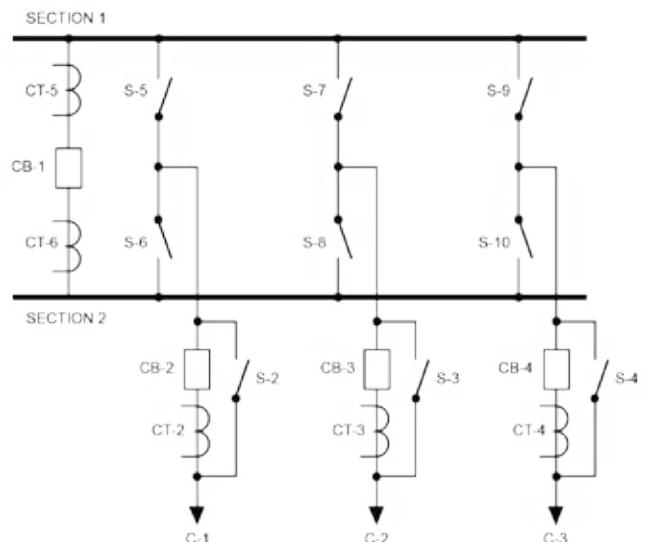

Figure 9. Double Busbar with Bypass

Bus Protection Systems

Bus protection systems must be suitable for application on any of the busbar arrangements as described. Beyond the standard protection requirements of reliability (both dependability and security for all fault events) and high speed (to limit the impact of a bus fault on the power system), bus protection systems need to be selective. This requires that a bus protection system only trip the feeder breakers that are actually connected to a faulted bus. For a single busbar system or a breakerand-a-half busbar system, this requirement is easily met, as all breakers can only connect to one bus. However, for more complex arrangements, such as the double busbar system, this requirement for selectivity is more difficult to meet. This sets the following requirements for bus protection systems:

- Providing independent protection zones with independent protection settings for each bus segment.

- Monitoring which bus segment each feeder or source to the bus is connected to.

- Tripping only the breakers connected to a faulted bus segment.

- Dynamically change each bus protection zone based on which feeders are connected.

THE CHALLENGE FOR TRADITIONAL SOLUTIONS IS THAT FIELD WIRING IS COMPLEX AND TIME CONSUMING, AND THAT THE BUS PROTECTION SYSTEM AND FIELD WIRING IS COMPLETELY DEDICATED TO BUS PROTECTION.

The first requirement is straightforward to meet for numerical bus protection systems. The second and third requirements are essentially wiring and I/O point count requirements. The status of each circuit breaker and each isolator switch (that determines which bus segment the feeder is connected to) must be brought to the bus protection system. Trip contacts for each circuit breaker must be supplied by the bus protection system. A typical feeder connected to the double busbar system of Figure 5 is going to require at least 6 status inputs (2 for the circuit breaker, 2 each for the isolator switches) and 1 contact output. Many more I/O points may be required based on actual arrangements and individual utility practices.

The fourth requirement is for a dynamic bus replica, that tracks which feeder is connected to which bus protection zone, through the status of isolators and circuit breakers, and issues trip commands to only the circuit breakers connected to a faulted bus.

Such a bus protection system is necessarily complex, and must provide for large numbers of contact inputs and outputs. There are 2 architectures in common use today.

Centralized Busbar Protection

In a centralized busbar protection system, all field wiring is brought directly to the bus protection relay. This requires massive amounts of field wiring connected to a single relay panel. The relay panel wiring, and field wiring, is complicated and time-consuming to design and install.

Distributed Busbar Protection

In a distributed system, field wiring for each feeder or bay is connected to a bay unit. Each bay unit is then tied to a central processing unit by digital communications. In most existing designs, the bay units are actually relays that send current measurements to, send equipment status to, and accept trip commands from the central unit via a proprietary communications method. Ideally, all field wiring ends in the feeder bay by connecting to the bay unit, but in many applications, the bay units are actually installed in the control house in panels adjacent to the central unit.

Busbar protection systems using both methods meet the protection requirements for complex bus arrangements. The challenge for traditional solutions is that field wiring is complex and time consuming, and that the bus protection system and field wiring is completely dedicated to bus protection.

Process Bus as Part of the Smart Substation

One possible definition of a "Smart Substation" is a substation that supports the ability to acquire the data necessary to support intelligent applications, and the ability to rapidly deploy intelligent applications as they are developed. A Smart Substation then supports more robust data acquisition, improved communications between access levels inside the substation, and more robust application platforms. Some goals and proposed solutions for the Smart Substation can be described as follows:

1. Reduce the use of copper wiring and the project execution time to a minimum by moving field labour to the factory.

2. Reduce the time of data collection to SCADA from the current typical time of 1 second to 1 power cycle, providing an effective real time system.

3. Implement one communication protocol for access levels.

4. Facilitate the data access for an easy asset management implementation.

"Process bus" is nothing more than the ability to communicate currents, voltages, equipment status, and equipment control commands between primary system equipment (the "process level") and application devices at the bay or station level. It is clear that process bus is a key piece of the Smart Substation. A process interface unit (PIU), installed at primary equipment at the switchyard, publishes sampled values of currents and voltages along with equipment status, and subscribes to equipment control commands via IEC 61850 message formats. This clearly replaces much field wiring, and makes data from the primary equipment available for all applications.

More formally, the design of new substations shall not only have the objective of reducing the initial investments and application suitability of devices but also minimizing the cost of long term maintenance and future refurbishments. The amount of corrective maintenance actions on the secondary copper wiring between the primary apparatus and protection and control IEDs as well on all copper connections at IEDs I/O boards can be significantly reduced. Therefore the concept of process bus permits the lifecycle view of design of electrical substations. Standardization of interfaces between primary equipment and secondary systems, reduction of the number of copper cables and the use of pre-connected cables permits the refurbishment to be done with less effort.

Furthermore, process bus supports the development of a protection, control and monitoring system (PC&M) approached from the utility enterprise perspective that recognizes and addresses needs, such as cost reduction and speed of deployment, while remaining at the same time reliable and secure. The process bus system originates from the following enterprise objectives:

*   Achieving cost savings

*   Reducing project duration and outage windows

*   Shifting cost from labour to pre-fabricated material

*   Targeting copper wiring as main area for cost optimization

*   Limiting skill set requirements

*   Supporting optimum work execution

*   Improving system performance and safety

*   Using open standard communications

Bus Protection Using Process Bus

A typical process bus architecture involves process interface units (PIUs) distributed throughout the substation switchyard to acquire signals at primary equipment. To implement bus protection, a bus protection system simply needs to connect to, and acquire data from, PIUs located at the appropriate current transformers, circuit breakers, and isolators. It is intuitive, then, that bus protection using process bus uses a distributed architecture, using PIUs as opposed to bay units. All protection and control functions will be implemented in a central relaying unit that connects to the appropriate PIUs.

In fact, bus protection is a good first use for process bus. The concept of a station-wide distributed architecture, with remote acquisition of data, is a well-established architecture for bus protection. Process bus simply changes the nature of the bay units by using PIUs, and uses an industry standard communications method, IEC 61850, as opposed to proprietary methods. The capital cost of a bus protection system using process bus and PIUs should compare to a traditional distributed bus protection architecture using bay units. The advantage to the process bus system is twofold: wiring costs should be reduced over traditional bus protection using process bus, and the PIUs installed for bus protection can also supply the same data to other relays for other zones of protection via process bus communications. Therefore, bus protection provides a built-in expansion and upgrade path for protection and control systems in the substation.

THE NEW DISTRIBUTED BUS PROTECTION SYSTEM CHANGES THE FOCUS OF BUS PROTECTION TO THAT OF APPLICATION BY REPLACING MOST OF THE FIELD WIRING WITH DISTRIBUTED I/O AND FIBER OPTIC CABLES.

New Distributed Bus Protection System Using Process Bus

This paper describes a new Distributed Bus Protection System using process bus. The goal of this new system is to start to meet the needs of the Smart Substation. The new system uses a central relaying unit for all protection and control functions, uses PIUs to acquire all signals from and provide control of primary equipment, and uses IEC 61850 communications between the central relaying unit and the PIU. The central relaying unit, in addition, collects all related and necessary data in one device. So this new Distributed Bus Protection System addresses the Smart Substation goals of reducing field wiring, implementing one communications protocol for all access levels, and starts on facilitating easy data access. In addition, this system can be a future platform for further applications for station-wide data.
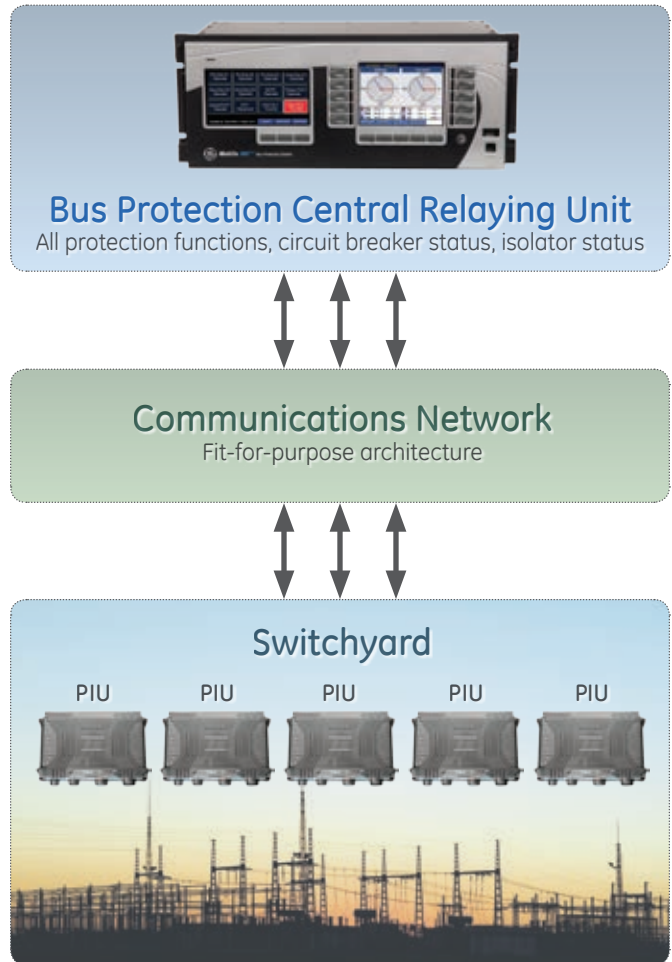

Bus Protection Central Relaying Unit
All protection functions, circuit breaker status, isolator status

Communications Network
Fit-for-purpose architecture

Switchyard
PIU   PIU   PIU   PIU   PIU

Figure 10. Overall Scheme of the Process Bus based Bus Protection System

Solving the Cost of Field Wiring

As previously described, bus protection for large bus architectures is costly due to the time to design, install and commission all of the associated field wiring. Every source in a bus protection zone requires extensive field wiring for the relay to acquire the current measurements and equipment status, and to issue control commands. Every signal used by bus protection requires a pair of copper wires. Every one of these wires between the primary equipment and the relay, and the terminations of these wires, must be designed, installed and commissioned for the specific project. Every one of these wires will be wired in series or parallel to protective relays associated with the zones of protection for the source, so this effort will be duplicated. This process is exceedingly labor-intensive, with most of the labor requirements being on-site manual labor. The end result is a very intensive and error-prone process that adds significant time and cost to every project and makes long term maintenance costly, and changes difficult to implement. This effort is very much the same if the project is installing a new bus protection system, or simply adding an additional source to an existing system.

The new Distributed Bus Protection System changes the focus of bus protection to that of application by replacing most of the field wiring with distributed I/O and fiber optic cables. The protection system consists of a distributed process interface (data acquisition and tripping) architecture using PIUs as bay units, with centralized processing performed by a single IED.

Extensive amounts of copper cables need to be distributed from each switchyard apparatus back to the control house

Many connections need to be made in each apparatus in the high voltage equipment switchyard

- All copper field wiring is between primary equipment in the switchyard and PIUs, which ideally should be located at the primary equipment in the switchyard. Fiber optic cables connect PIUs to the central bus protection unit.

- For all applications, the installation is then identical: the physical interface consists of PIUs connected to a fiber optic cable. A single IED is mounted in a relay cabinet, with the process cards in the unit patched to the fiber optic cables coming from the PIUs. The size of the IED, and the fact that there only fiber optic connections to the IED (with no field wiring) simplifies the relay panel, Therefore the relay panel design for all busbar arrangements and bus protection schemes is identical: one central relaying unit mounted in a relay panel, along with fiber optic patch panels.
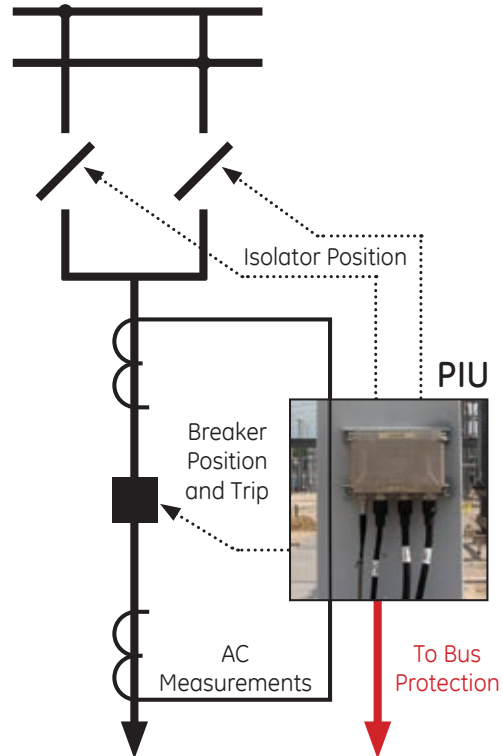

Figure 11. PIU Field Wiring

As previously described, the new Distributed Bus Protection system uses PIUs as bay units, that both samples currents and voltages, and provides contact I/O for equipment status and control. Once a PIU is installed in a Bus Protection system, the PIU can interface with any other device that supports sampled value messages as per the IEC 61850 standard implemented with the correct profile. Rather than duplicate field wiring from the bus source for a feeder zone of protection, simply patch any compliant family to the fiber optic cable from the PIU to add acquire the same signals.

Protection

The central relaying unit of new Distributed Bus Protection system provides robust and reliable protection for all bus protection applications. Highlights of the protection functions related to bus protection include:

- Multi-zone differential protection with both restrained (dual-slope percent or biased) and unrestrained (unbiased or instantaneous) functions incorporated. Differential protection is fast (typical response time: 1 power system cycle) and secure. Security is achieved by using a fast and reliable CT saturation detection algorithm and a phase comparison operating principle. Security is further enhanced by support for redundant process interface units (Bricks). Supports both three-phase tripping and individual phase tripping.

- Dynamic bus replica functionality and multi-zone protection (up to 6 zones) is supported allowing application of the Bus Protection to multi-section reconfigurable buses. A zone expansion/contraction to an open breaker feature is included. Isolator position monitoring for up to 96 isolators.

- Check-zone functionality configured by programming one of the differential zones to enclose the entire bus.

- Additional bus protection functions including end fault protection, breaker fail and overcurrent protection for each bus source, with CT trouble monitoring for each bus zone

All protection and control functions are implemented in the central relaying unit, including breaker failure. The PIU is intended to be a device located at primary equipment in the switchyard, and as such, is only a simple I/O device, and has no sophisticated processing. Sophisticated processing and application functions are best utilized in the central relaying unit.
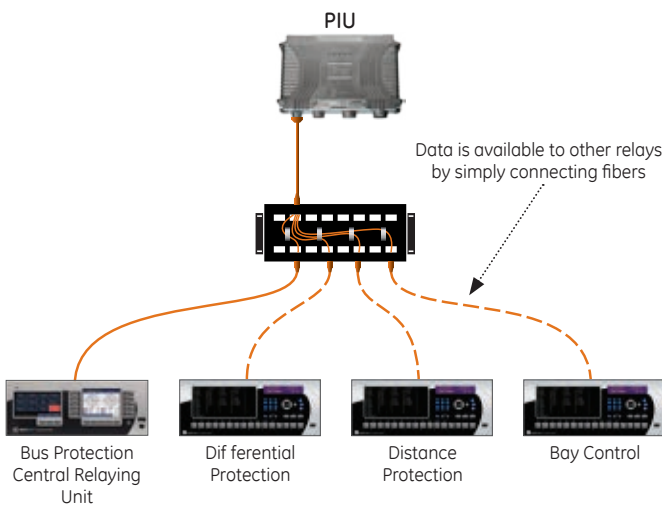

Figure 12. Process Bus and Expansion

Applying the New System

The new Distributed Busbar Protection System can be applied on all of common busbar arrangements previously described in this paper. Because all data is acquired through PIUs and IEC 61850 communications, configuration can be made using common object-oriented programming techniques.
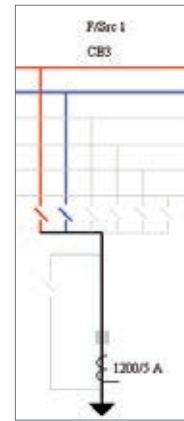

Figure 13. Bus Source Concept

The central relaying unit of the new System includes specific functions such as circuit breaker status, isolator switch status, and current transformer connections and ratios. The System also defines the concept of the "bus source", which, at heart, is a function block that ties together the status and connection functions for one individual bus feeder or circuit. Therefore, the bus source is responsible for determining which bus segment and bus differential zone a specific feeder or circuit is connected, and is responsible for issuing the appropriate trip command to the circuit breaker.
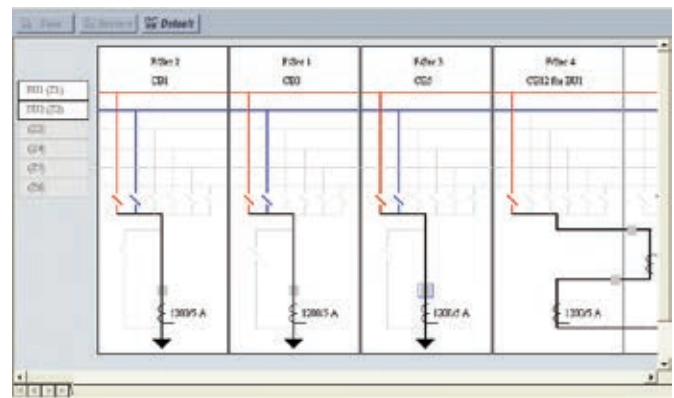

Figure 14. Dynamic Bus Replica Concept

The bus protection carries the object-oriented modeling even farther. The dynamic bus replica, to ensure protection zones match the actual power system conditions, is another function block. The dynamic bus replica is simply multiple bus sources connected together through configuration.

Quickly Expand the Protection System Through Process Bus

The Bus Protection System is intended to operate as a standalone, distributed bus protection system. The bay units for this system are PIUs, part of an IEC 61850 process bus solution. Once the PIUs for the Bus Protection are installed, process bus data is available for use for any other zone of protection. The PIUs, then, are a distributed I/O interface for all protection functions and zones, not just the Bus Protection

With the Bus Protection in place, installing line protection or feeder protection is a simple process: mount the relays in a panel, and patch to the fiber optic cable from the appropriate PIUs. The only requirement is the relays must implement the appropriate IEC 61850 profile to interface successfully with the PIUs.
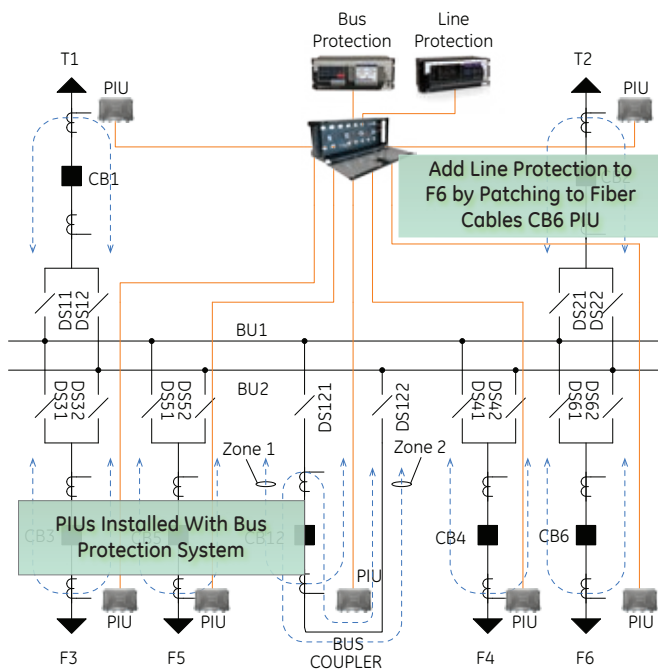

Figure 15. Easy Protection Expansion

Use the Distributed Bus Protection System as a Centralized DFR

In keeping with one of the requirements of the Smart Substation, the new Distributed Bus Protection System can be used to supply additional functions to provide better access to data. With access to data across the entire substation, the new System also has the capability to function as a basic centralized Digital Fault Recorder (DFR). While not as full-featured as dedicated DFRs, the unit includes specific transient recorder settings and digital triggers to initiate recording. The Distribute Bus Protection System can capture up to 50 individual oscillography records at sampling rates of up to 128 samples per cycle. Oscillographic data will include AC waveform channels from every enabled bus source and every enabled protection zone differential and restraint current. The oscillographic data can also include up to 384 digital channels. In addition, the System provides an event recorder that records the last 8,192 events time tagged to 1 microsecond.

The Distributed Bus Protection System as Component in the Smart Substation

The new Distributed Bus Protection System described in this paper starts to meet the goals of the Smart Substation. The use of process bus and process interface units (PIUs) as bay units reduces the use of copper wiring and project execution time to a minimum. Communications between the central relaying unit and PIUs uses the common communications protocol of IEC 61850. The system also facilitates the acquisition of data from across the substation for presentation to other devices, station control, and traditional SCADA services. The new system supports the rapid development of other station-wide functions, and has started the implementation of a station-wide fault recorder. And finally, installing this system is a low-risk and cost-effective way to start the installation of process bus protection systems. For the same cost as a traditional distributed bus protection system, easy expansion of other protection systems is nothing more than an add-on function.

Cyber Security and Process Bus

Process bus systems can introduce challenges related to cyber security, especially in North America. NERC Critical Infrastructure Protection rules will define merging units or PIUs as critical cyber assets, and subject to implementing appropriate cyber security protection. This new Distributed Bus Protection System is designed specifically to address the cyber security problem. The communications architecture is a point-to-point architecture, with no remote access to the communications between the Protection central unit and the PIUs. The messaging between the relay and the PIUs is completely, physically sealed from the outside world, so there are no special concerns with regards to cyber security.
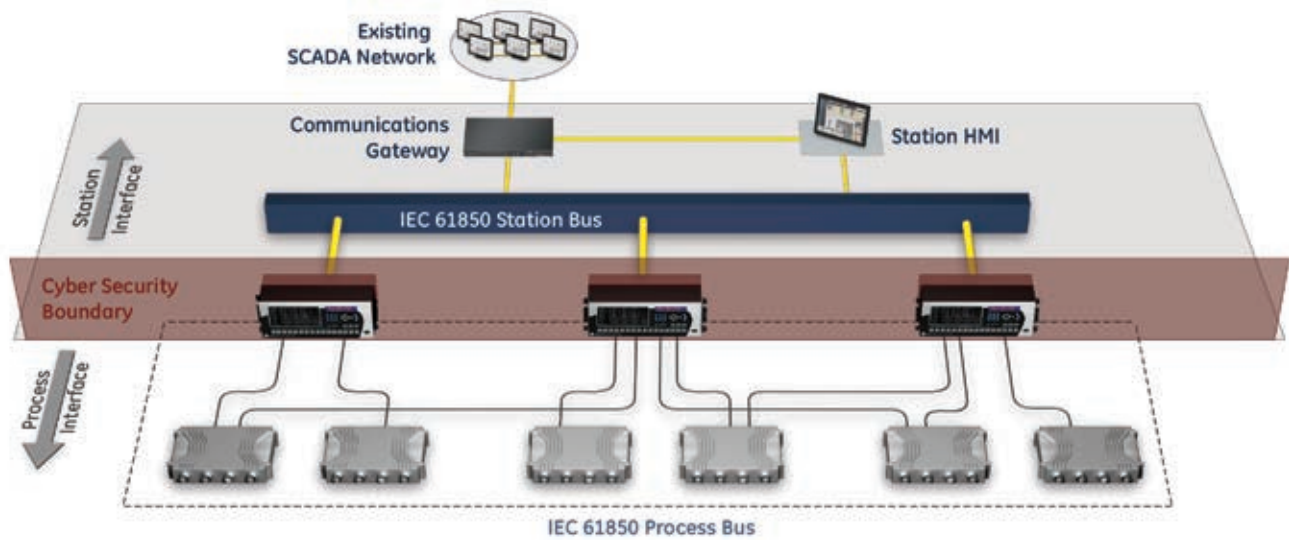

Figure 16. Natural Cyber-security Barrier

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distribution automation

Reviewing the various levels of remote control and Distribution Automation that are typically in operation on electric utilities' distribution systems today.

B. R. Flynn, GE Energy

System design
CONSIDERATIONS

This paper reviews the various options for automating a distribution system utilizing a range of techniques and algorithm locations with a comparison of the various levels and a discussion of the advantages/disadvantages.

DA Applications

Utilities today rarely deploy the same level of automation on all feeders but usually select from a range of standardized options to deploy on selected circuits depending on several factors. The assessment of these factors usually occurs on a circuit-by-circuit basis and includes:

- Load criticality

- Reliability problems

- Customer density

- Geographic factors such as feeder length

- New construction on a circuit

- To meet reliability targets and objectives

- Economic and reliability rate recovery

- Availability of alternate sources

- Existing physical infrastructure of controllable devices

- Existing compatible communication infrastructure

Each level described in this paper contains a different amount of automation or control with varying levels of communications for remote operation. The outage benefits of these levels have been estimated and are represented as typical Customer Minutes Interrupted. Each of these levels was then analyzed based on the expected total cost of deployment. Consequently, a CMI/$ is calculated.

Case 1: Manually-Operated Disconnect Switches

Figure 1 presents a simple example of a pair of feeders each with two normally closed switches looped together with a normally open tie switch at SW3. While this is a very simplified circuit compared to today's modern distribution systems, it can serve to highlight the differences between various levels of control or automation.

Case 1 provides a base case for use as a comparison against the other cases. It consists of a simple looped feeder with two field operable manual disconnect switches (Sw 1, 2, 4, 5) on each feeder connected by a tie-switch (Sw 3) allowing the unfaulted sections of a circuit to be manually restored from an alternate source. The substation feeder breaker (Fdr 1, 2) is assumed to have SCADA communications and normal over-current protection in both substations.
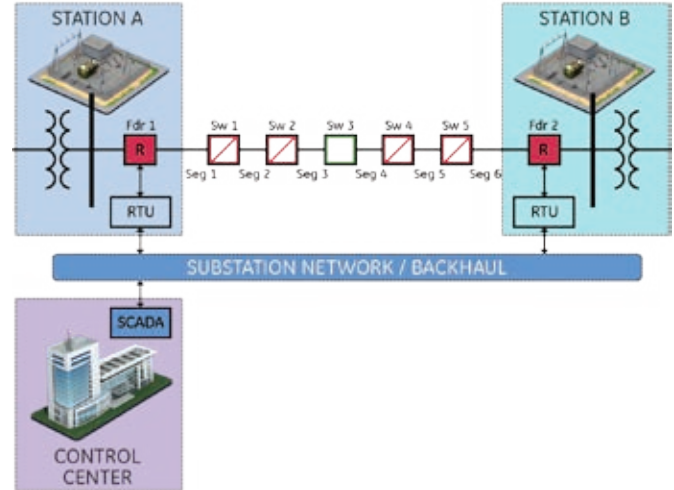

Figure 1. Case 1: Manually Operated Disconnect Switches

Case 2: Automatic Circuit Reclosers without Remote Control

Case 2 replaces the manual disconnect switches with Automatic Circuit Reclosers (ACRs) along the feeder. This level of automation allows several automatic isolation points which will reduce the customer outage minutes. For example, customers served from Station A in Seg 1 will not experience an outage for faults in Seg 2 or 3 similarly for customers in Seg 2 for faults in Seg 3 because the ACR will detect faults down the feeder and open Sw 1 or 2.

This Case assumes that no field communications exist to the distribution feeder devices beyond the SCADA connection to the stations described in Case 1.

Abbreviations

ACR: Automatic Circuit Recloser (labeled 'R' in drawings)

AMI: Advanced Metering Infrastructure

CMI: Customer Minutes Interrupted

CVR: Conservation Voltage Reduction

DA: Distribution Automation, referred to as FDIR

DMS: Distribution Management System

FD: Fault Detector

FDIR: Fault Detection Isolation and Restoration

IVVC: Integrated Volt/VAR Control

MAIFI: Momentary Average Interruption Frequency Index

NPV: Net Present Value

SAIDI: System Average Interruption Duration Index

SCADA: Supervisory Control and Data Acquisition
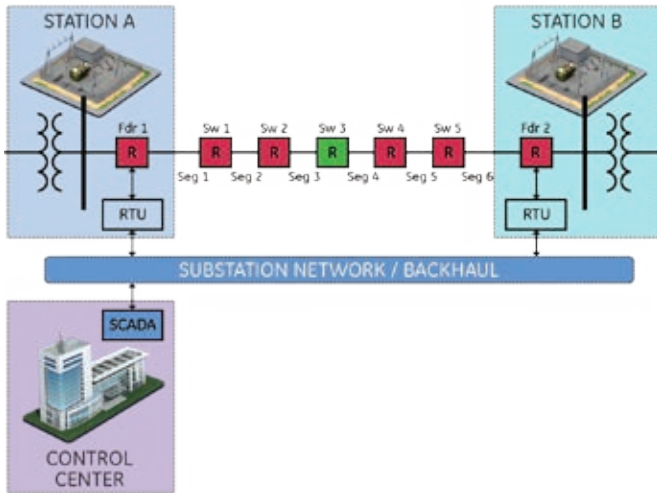
VAR: Volt-Ampere Reactive

Figure 2. Case 2: Manually Operated ACRs

Case 3: Remotely Operated Automatic Circuit Reclosers

Case 3 adds communications to the ACRs and tie switch along the feeders. This allows SCADA control and indication of Switches 1-5 in addition to the feeder breakers in the substations. After the station feeder breakers or ACRs trip to lockout, the dispatcher can remotely assess the circuit conditions and fault location then isolate the fault segment and restore unfaulted sections from the alternate source. Automatic operation is limited to the trip-reclose action of the relays in the ACRs or stations.
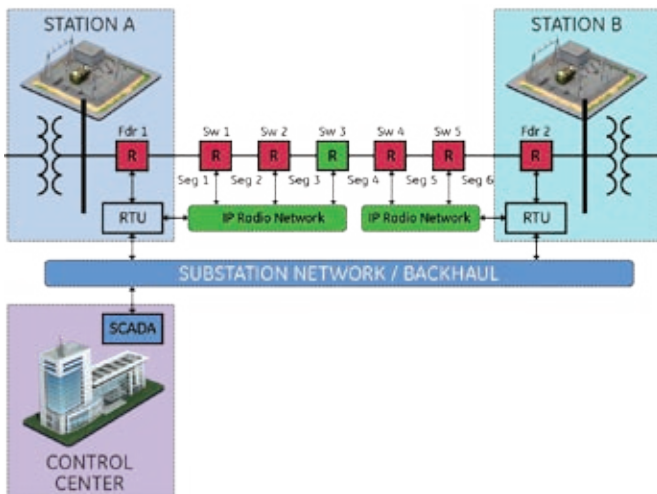

Figure 3. Case 3: ACRs (labeled R) with Remote Control

Case 4: Rule Based FDIR

This case analyzes the benefits of the addition of a rule-based a FDIR algorithm to the circuit. Rule based algorithms operate on a static set of rules designed to operate under typical circumstances. The rules are designed to simulate the normal isolation and restoration switching steps that would have been handled manually in response to a fault.

The deployment of a rules based FDIR algorithm can occur in switch controllers, station or control center. The basis of the FDIR algorithm is heuristics, not on an electrical network model. Depending on safety and operational procedure checks, FDIR will automatically isolate faults along the feeder by opening the switches around the fault. The algorithm will then automatically restore any unfaulted sections via alternate sources depending on the availability of that source. For example, customers along Seg 1 will be unaware of faults in Seg 2. Customers in Seg 3 will automatically be isolated from the fault in 2 and be restored by closing Sw 3 if Station B has the capacity to feed the additional load in Seg 3. This is determined typically by adding the prefault load measured in Seg 3 with the measured Fdr 2 load in Station B. This value is then compared to the capacity ratings limits for Fdr 2. Sw3 is closed only if the total load is below the limits
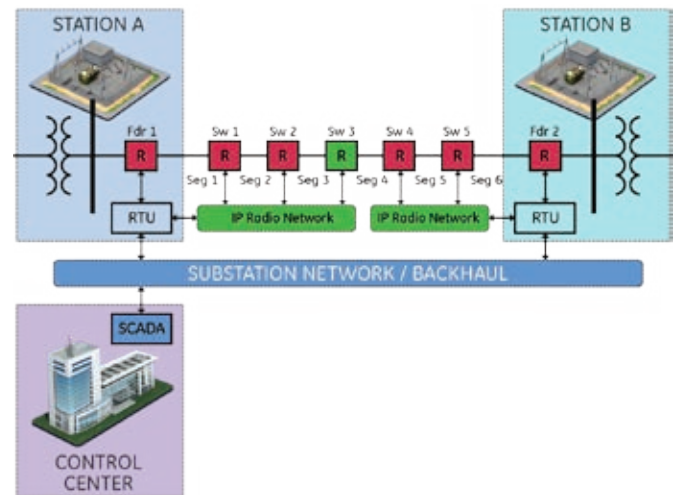

Figure 4. Case 4: Rule-Based Fault Detection Isolation and Restoration (FDIR)

Case 5: Closed Loop Automation

Case 5 adds an advanced switch configuration where the tie switch, Sw 3, is configured to remain closed. Some utilities are deploying closed loop circuits for their most critical loads in an attempt to minimize outages. Paralleling portions of the distribution system as shown in Fig 5 can present significant challenges that must be addressed through studies and recommendations from distribution planning, distribution operations, system protection and maintenance.

This configuration has significant protection and operational considerations and should only be used after careful distribution system planning and protection studies. The FDIR algorithm in this system is installed in the controllers at Fdr 1, 2 and Sw 1-5. The system design automatically isolates faults anywhere along the feeder while minimizing the outage only to the faulted segment. If a fault occurs in Segment three, the controllers at Sw 2 and 3 detect the fault and trip to isolate the fault. They then send blocking signals to the switches back toward the feeder breakers at each end of the feeder. This is critical as all of the relays in this circuit will detect the fault and trip unless they receive a blocking signal from a controller closer to the fault.

This circuit requires high-speed dedicated communications between the switches on both feeders. Typically, the blocking

signal needs to be communicated from one switch to all the others in less than 5 cycles. Any relay not receiving a blocking signal will open its breaker. A limitation of this scheme is that if a malfunction occurs in the communications during a fault, the resulting outage could be greater if a blocking signal is not received at switches beyond the faulted segment. This can potentially result in an interruption to all of the customers on both feeders.
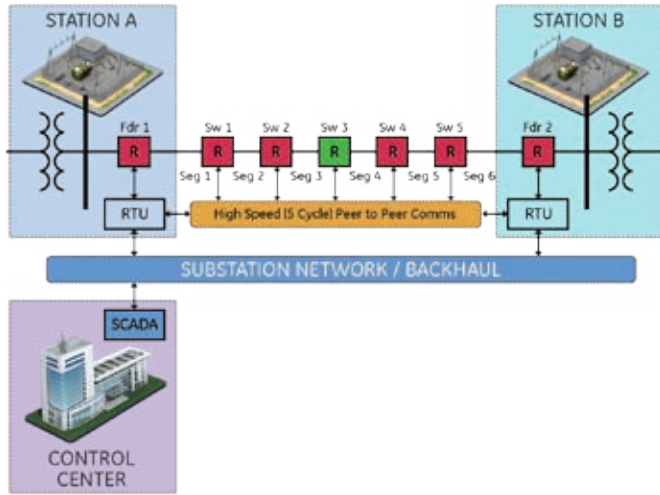

Figure 5. Case 5: Closed Loop Automation

Case 6: Connectivity Model Based FDIR

This case analyzes the benefits of the addition of a connectivity model driven FDIR algorithm to the circuit. Connectivity model based algorithms operate on an actual connected state of the grid because the model contains a representation of how the various distribution devices are connected together. It allows unfaulted load to be restored under many more complicated alternatives than a rule based system. This includes a temporary cuts and jumpers installed on the grid and added to the connectivity model by the Distribution Management System (DMS) dispatcher. The connectivity model is updated either manually by the dispatcher or automatically from real time inputs from status and analog values from the field devices. The FDIR algorithm can safely and efficiently restore unfaulted sections of lines more frequently than for rule based algorithms.
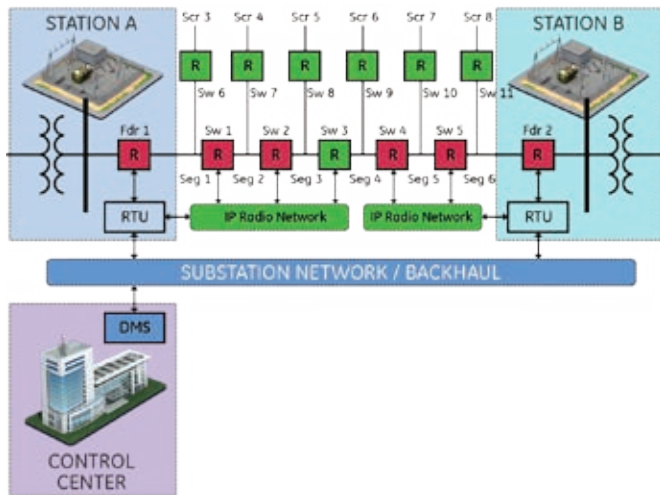

Figure 6. Case 6: Connectivity Model based FDIR

The drawing in Figure 6 shows the possibility of multiple additional sources for each segment of the feeder. This case adds alternative sources Src 3-8 to Seg 1-6. The analysis then included an estimate of the percent of time the alternative sources were available and utilized for faults in each segment of the feeder.

Because the model then reflects the current state of the system, it allows the FDIR system to more accurately reflect the complexity of the distribution grid and restore unfaulted segments of the system under a wider variety of circumstances. The connectivity model can be deployed centrally in a DMS or remotely in the station.

A connectivity model driven system also can provide additional value to distribution operations not modeled in this analysis, including: Complex automatic circuit rerouting where the normally open tie-point is moved to different switches along the feeder for capacity constraints or the ability to restore circuits automatically from alternate sources on loss of primary source at the substation, or the ability to transfer unfaulted sections based on forecasted future capacity from the alternate source.

Case 7: Fully Integrated Solution with Load Flow FDIR

This case analyzes the improvements resulting in a load flow based FDIR system. The load flow model adds to the connectivity model from case 6 and includes electrical characteristics of the distribution system. The load flow model has the ability to dynamically calculate system nodal analog values such as voltages and power flows at points that are not currently being measured. This ability to 'fill in' analog values from areas of the distribution grid provides the ability to safely and reliably operate the system closer to stability or thermal limits. The model can also be used in a study mode, allowing the dispatcher to review impacts of switching scenarios prior to actually switching field devices.
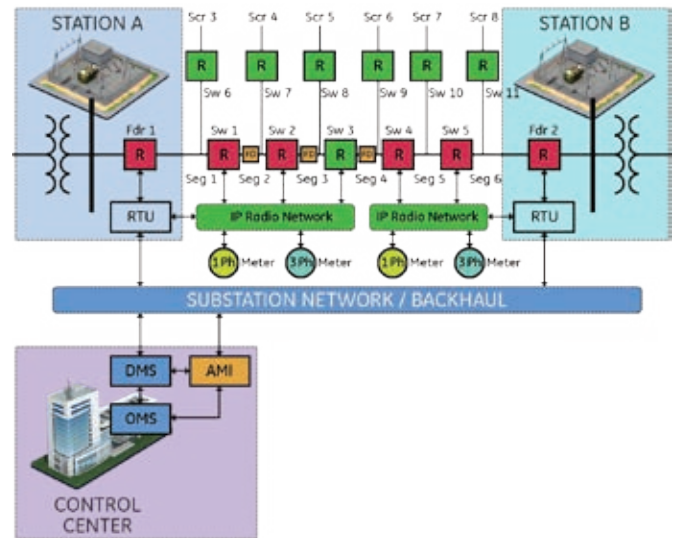

Figure 7. Case 7: Load Flow Model based FDIR in a Fully Integrated Solution

The load flow model is normally installed as part of the DMS system. In a fully integrated solution, outage and fault date is received from additional sources. This includes outage data from the Outage Management System (OMS), customer out-age information from the meters in the Advanced Metering Infrastructure (AMI) system, and from fault detectors (FD) elsewhere on the distribution line.

This integration allows the FDIR algorithm and Distribution Operators to further reduce customer outage minutes.

A fully integrated system adds the ability to detect outages virtually anywhere on the circuit and incorporate that data into the DMS and OMS. This helps operations personnel identify faults more quickly and accurately, and verify customer outage restoration from their meter pings which helps determine the presence of nested outages. This system also improves on the ability to restore unfaulted segments more frequently than other methods. All the additional benefits of a fully integrated system are too numerous to capture and analyze in the scope of this analysis. This analysis focuses on the improvement to customer outage minutes from the improved restoration and fault localization capabilities of a fully integrated system supported by a load flow model.

AUTOMATICALLY UPDATING THE STATION BASED FDIR NETWORK MODELS FROM THE CENTRAL OFFICE REDUCING MAINTENANCE COSTS WHILE REDUCING OUTAGE TIMES.

Analysis

Operational Definitions

The results presented in this paper were compiled from outage analysis work with two different electric utilities . That analysis compared various levels of automation and computed the customer outage minutes for various fault scenarios given a base set of assumptions. These assumptions, summarized in this section, were assigned a typical value according to the case being analyzed. These values were determined based on actual and estimated time durations from those two utilities. The variables included:

Fault Likelihood - This is the likelihood of a particular fault occurring in a section of feeder with a total of 100% for the three segments.

Number of Customers – This is the distribution of customers in each section of the feeder including laterals located in a particular section.

Dispatcher Busy - This variable represents additional time the dispatcher may take to respond to an outage during times of high workload for the various cases.

Simple Travel Time - This is the average travel and response time for the Troubleshooter to arrive in the area and begin inspecting the line for trouble.

Crew Travel Time - This is the average travel and response time for the crew to arrive in the area and begin repairing the line.

Simple Repair Time - This is the average time it takes the Troubleshooter to complete repairs for simple faults, for typical tree limb related faults.

Complex Repair Time - This is the average time it takes a crew to complete repairs for complex faults which includes downed poles or conductors.

Switching Time - This is the average time it takes a Troubleshooter to complete manual switching in Cases 1 & 2 since there is no remote control of the switches.

Percent Complex Faults - This is the percent of faults that are complex in nature where the Troubleshooter would indicate the need for a crew to be dispatched, which would result in longer repair times.

Percent Alternate Source Used – This is the percent of times that the alternate source is used for faults in feeder sections #1 and #2 when the Tie is manually, remotely or automatically controlled

Percent Time Tie Closed in Case 5 – This is the percent of time that the tie switch is closed in Case 5, accommodating occasional situations where the Sw 3 should not remain closed.

Percent Other Source Used – This is the percent of time that the other source (Src 3-8) is used in Cases 6 and 7.

Faults per Year Feeder – This variable represent the average number of faults per year on the feeder that require a response, including fuse and ACR lockout trips. This value does not including momentary trips with a successful reclose.

Percent Backbone Faults – This represents an estimate of the percentage of faults that are on the backbone of the feeder instead of possibly being isolated on a radial behind a fuse.

Customers per Fuse – This variable represents the average number of customers behind a single phase fuse, not shown in the drawings.

Number of Circuits – This value represents the total number of circuits that could be good candidates for application of some level of automation.

Discount Rate – The annual percent discount rate used in the Net Present Value Calculations (NPV).

Project (Book) Life – The number of years used in the NPV Calculations.

Financial Analysis

The total net Capital and O&M costs were calculated for each case to be used in the final cost/performance comparison. The net total costs for each case were calculated and converted to present value using a simplified NPV calculation. The estimated costs consist of capital expenses and the associated O&M expenses. They include costs to upgrade switch/ACR, communications and stations and any control center upgrade costs. The calculations also include the additional full-time equivalent costs of employees required to operate and maintain the controllers, communications and algorithm additions in each case. These assumed costs have been normalized into a per-circuit and per-customer basis as summarized in the table below. These costs were included as a reference and will vary significantly depending on the feeder being upgraded, differences between overhead and underground systems and geographic and other local considerations.

	Per Circuit	Per Customer
Case 1	$13,750	$8
Case 2	$125,000	$69
Case 3	$170,000	$94
Case 4	$250,000	$132
Case 5	$500,000	$270
Case 6	$260,000	$139
Case 7	$275,000	$146

Table 1. Initial Capital Cost Estimates

From the table above, all of the costs are on a per feeder basis and include only the portion of SCADA, DMS or AMI costs, in the applicable cases, attributed to outage reduction, not the entire SCADA, DMS, or AMI costs. System costs were then allocated across a typical utility deployment assuming a system deployment across 20% of all circuits. Studies have shown that many utilities automate their worst performing circuits first, which often account for their highest level of outages.

The costs of Case 5 are significantly higher than the other cases because they include additional costs for high-speed communications. New high-speed dedicated wireless communications equipment will significantly reduce the costs to deploy this level of automation. However, it will not eliminate the other planning and operational issues caused by operating the system with a closed tie on a regular basis. Consequently, application of this level of automation should occur only after significant planning and study.

Summary of Results

The following chart illustrates the customer outage minutes reduced over the base case as determined from the analysis. The analysis has been developed with and validated by two different North American electric utilities. The CMI data is represented in outage minutes reduced per customer per year. The time durations for each case were calculated with a dispatcher busy time of 15 minutes. The costs represent the NPV per customer of total costs from Table 1. The $/CMI represents the relative cost performance value for each case.

Case	CMI/yr. Saved	Costs	$/CMI
Case 1	-	-	Base
Case 2	11 min.	$69	$6.31
Case 3	56 min.	$94	$1.68
Case 4	85 min.	$140	$1.65
Case 5	99 min.	$227	$2.80
Case 6	88 min.	$146	$1.66
Case 7	92 min.	$153	$1.66

Table 2. Initial Capital Cost Estimates

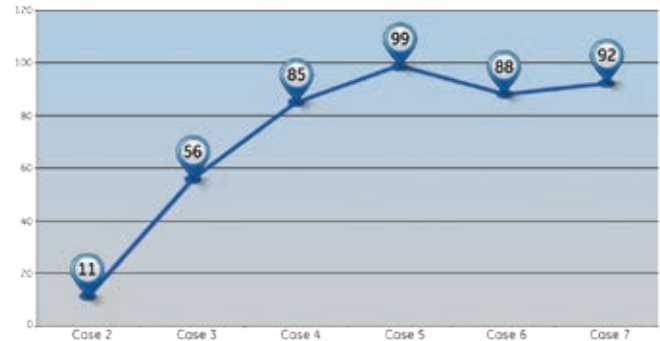The CMI data is shown graphically in figure 8 below.

Figure 8. Customer Outage Minutes Saved over Case 1

The CMI/$ is shown in the following figure.

Figure 9. Cost of Customer Outage Minutes Saved

FDIR Algorithms

Utilities frequently ask for a comparison of the differences between the various architectures or more specifically, the location of the algorithms. This whitepaper has focused on the benefits of various types of FDIR algorithms but not specifically on the differences in architectures. This section will compare the three common architectures related to the location of the algorithms. They will be referred to as: 1) Peer to Peer System consisting of FDIR algorithms located in the device field controllers with communications between those controllers and a centrally located SCADA master; 2) Station Based Systems consisting of algorithms located in the substation that communicates with the neighboring stations, the field switches or breakers and the centrally located SCADA master; and 3) Control Center Based Systems consisting of algorithms primarily located at the control center with communications from control center to field stations, switches, breakers or other devices often including ties to the OMS and AMI systems.
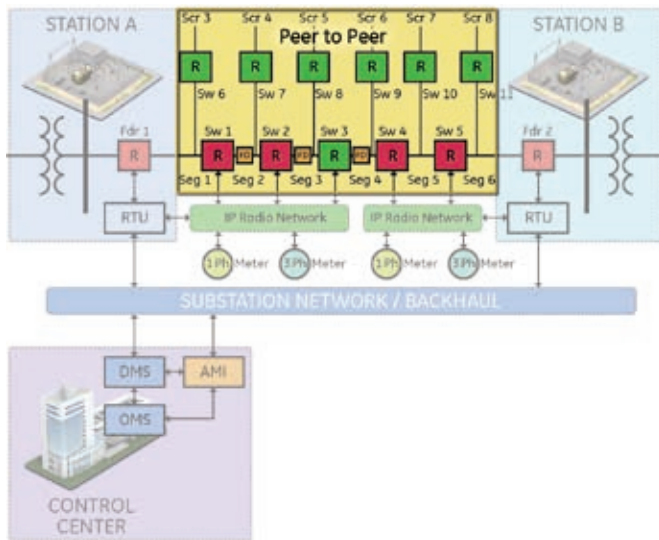
Peer to Peer FDIR

Figure 10. Peer to Peer algorithm location

In the case of Peer to Peer FDIR, the algorithm is located in multiple controllers at the field devices Sw1-5. The FDIR algorithm typically utilize a rule-based system and makes coordinated decisions by communicating information such as fault, load, and switch position between controllers. Case 5 is a special high-speed communications example of a Peer-to-Peer system where actions are coordinated between controllers.

Station Based FDIR

Station based FDIR is the type of system where the algorithm is located in a substation controller. The algorithm is typically rule based but more modern systems include a limited connectivity model. The substation communicates with the field devices, Sw 1-5 on the feeders connected to that substation and with controllers in neighboring substations, between Station A and B. The station controllers then make decisions based on data collected from the field and send operation commands back to the field controllers.
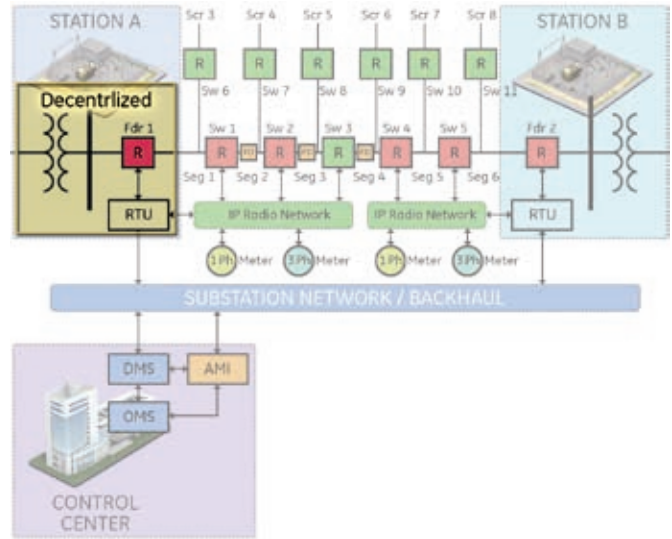

Figure 11. Decentralized station based algorithm location

Control Center Based Systems

Control Center located FDIR is the type of system where the algorithm is part of a DMS or SCADA master. This system can operate under a rule based model, a connectivity based model or a load flow model. The control center based system communicates with the devices in the stations and the feeders across the grid, then makes decisions and sends commands to the controllers at the various switches/breakers. The control center based system is sometimes connected with other systems to improve the ability of the models including the OMS and AMI systems.
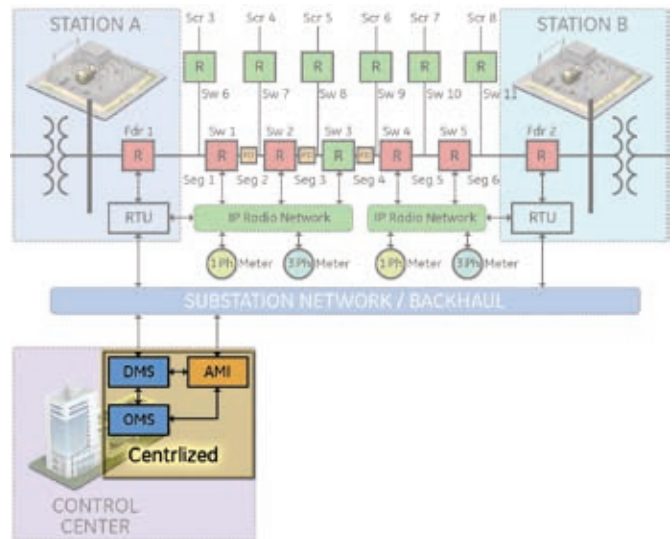

Figure 12. Centralized algorithm location

Comparison of Architectures

This section will present a summary review of the various differences of the three architectures.

Architecture Comparison	Peer to Peer	Station	Centralized
Operations speed	<30 Sec	<60 Sec	<90 Sec
Costs (Cap & OpEx) small deploy	low	med	high
Costs (Cap & OpEx) large deploy	high	med	low
Deployment speed for small	short	med	long
Open protocols	n*	y	y
Interoperable other suppliers	n*	y	y
Communications	Peer to peer	Peer to station	Various
Requires backhaul comms	n	n	y
Secure communications	y	y	y
Remote configuration	n*	y	y
Cuts & jumpers	n	n	y
Integrate with GIS/OMS/AMI	n	n	y
Compatible with IVVC, AMI, OMS	n	Y	y
Rules based model support	y	y	y
Connectivity model support	n	y	y
Load flow model support	n	n	y
*often proprietary			

Table 3. Initial Capital Cost Estimates

The table above highlights the primary differences between the three architectures. Each item will be discussed briefly below.

Operation speed – all the architectures operate within the normal SAIDI limits, however, the less communications and computation required the faster it operates.

Costs – typically for small deployments peer to peer and station systems are cheaper, large deployments centralized systems are less.

Deployment time – it is typically easier and quicker to deploy, test and commission a smaller less complicated system consequently peer and station based systems are faster.

Open Protocols – most systems utilize non-proprietary protocols, however, many peer systems operate using proprietary protocols making them available only from one supplier. Newer peer systems using IEC 61850 are non-proprietary and more interoperable with other systems or suppliers.

Communications – The communications system can is a critical component of any of the systems. Peer based systems require peer to peer and station communications is difficult for long feeders. Centralized systems, while requiring a backhaul communications, is the most flexible allowing for direct communications to field devices vs. requiring communications to route through a station or between all the peers. It is also critical that the system be open and non-proprietary. Standard IP based communications systems can better accommodate in band remote configurations which helps reduce system configuration costs.

Integrate with GIS/OMS/AMI – it is much easier to integrate data from different systems together when they are all centrally located.

Cuts & Jumpers – is typically only supported in a central system.

Hybrid approach

Many utilities adopt a hybrid approach consisting of initially deploying a less sophisticated FDIR system on a smaller number of circuits. This approach allows the utilities to transition to a more sophisticated control system with a larger deployment after they have adapted their business processes to new FDIR algorithms. This helps utilities continue to maintain safety while helping control deployment costs.

Often the most challenging element of these systems is the communications network. The most practical approach followed by utilities today is to plan the communications infra-structure to accommodate future needs and other functionality, such as IVVC or AMI. This often requires a more open and non-proprietary approach and usually requires higher bandwidth and lower latency than a single function system.

LEVERAGING THE FASTER RESPONSE TIME OF THE STATION OR PEER SYSTEMS COMBINED WITH THE RESTORATION FLEXIBILITY OF THE CENTRAL LOAD FLOW-BASED FDIR REDUCES OUTAGE TIMES.

Challenges and Future Recommendations

The intent of this analysis is to help electric utilities to better understand and evaluate the various levels of distribution automation available today. Depending on the local Utility Commission or Regulator, Distribution Automation can be difficult to justify economically. Most customers have an expectation of electrical service reliability and are not normally willing to cover the investment necessary to reduce outage times. Consequently, the importance of understanding the range of costs and benefits is critical when determining the appropriate level of automation deployed.

Recognizing the many situations and conditions that utilities face on their individual networks, GE's philosophy is to analyze the various options for utilities and determine the best solution based on the utility-specific situation, with the under-standing that there is no one-solution-fits-all. For example, many utilities deploy simpler systems rule based systems for the first few feeders then migrate to a connectivity or load-flow systems approach as the number of deployed circuits increases. Many of these utilities often start with station or peer based systems and migrates to a centrally located system leveraging the advantages for larger systems. Fewer utilities deploy Case 5 because of the costs and complexity; however, future wireless technologies may offer reduced costs.

Some concepts to consider include:

- Analyze the benefits of an Integrated Volt/VAR Control (IVVC) or Conservation Voltage Reduction (CVR) system, and subsequent deployment of a system that offers both FDIR and IVVC to generate positive cash benefits that can be used to leverage the expansion of FDIR across the net-work.

- Apply the higher level of automation to the worst performing circuits and use the results to help prioritize the future deployment of automation across other circuits, in line with consumer expectations, utility reliability performance and budgetary goals, and engineering/construction capacity.

- Analyze the appropriate circumstances for the application of Case 5 as the CMI performance of this level of automation is superior. Investigate future use of non-proprietary and less expensive wireless systems using IEC 61850.

- Investigate the additional costs and value from an integrated DMS, OMS and AMI to determine the actual cost/benefit cross-over point depending on the number of circuits deployed.

- Analyze the impacts of a high penetration of renewables on the distribution grid and the needs for a centralized approach to manage the added complexity.

- Leverage the faster response time of the station or peer systems combined with the restoration flexibility of the central Load Flow-based FDIR to reduce outage times.

- Automatically update the station based FDIR network models from the central office to reduce maintenance costs while reducing outage times.

- Utilize advanced visualization capabilities coupled with tighter integration with customers through information collected from customers through mobile social networking to reduce truck rolls and outage times.

- Emphasize efforts to reduce the number of faults and maintenance costs through advanced distribution management systems that provide proactive maintenance monitoring and diagnostics and new line monitoring techniques.

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[i]This paper leveraged the following:

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protection and control systems for pulp and paper

As industrial facilities look for low-hanging fruit to reduce their overhead expenses, the maintenance and testing of the protection system is an obvious target.

Craig Wester, GE Digital Energy
Terrence Smith, GE Digital Energy

FULLY MONITORING protection and control systems

Modern microprocessor based relays offer many advantages over their electro-mechanical counterparts. One of these advantages is the ability to monitor the relay health and the health of the protection and control system and raise an alarm if any monitored function is amiss.

Abstract

Modern microprocessor-based relays offer many functions, which are underutilized by the industry. This paper will discuss using relay functionality to fully monitor the protection and control system, which will identify problems within the system before they manifest themselves by miss-operation. This paper will also discuss the use of these monitoring systems to lengthen the time intervals required for periodic testing of the protection and control system. Some of the monitoring techniques to be discussed include: trip coil, close coil, and lockout relay monitoring, usage of relay self-test alarm contacts, instrument transformer failure detection using analog GOOSE messaging & other level detection/comparison methods, breaker restrike detection, station battery monitoring, oscillography cross-triggering, automated contact input & output testing and natural testing by event analysis.

Introduction

Modern microprocessor based relays offer many advantages over their electro-mechanical counterparts. One of these advantages is the ability to monitor the relay health and the health of the protection and control system and raise an alarm if any monitored function is amiss. This ability to monitor the protection and control system gives the industrial facility the capability to continuously insure the health of the protection and control system. The only way to insure confidence in an unmonitored protection and control system is to test the system. This includes not only testing the protective relay functions, but also testing the overall protection and control system.

As industrial facilities look for low-hanging fruit to reduce their overhead expenses, the maintenance and testing of the protection system is an obvious target. The health of the protection and control system directly relates to the availability of the industrial facility. A protection and control system that operates erroneously can needlessly take down processes. A protection and control system that fails to operate can allow more extensive damage to the facility and lengthen outage times.

Modern microprocessor based relays provide opportunities to utilize monitoring of the protection and control system to reduce maintenance costs by reducing maintenance testing. The primary mechanism that industrial facilities can utilize to lower their maintenance costs is to increase the time interval required to test their protection systems. Monitoring the protection and control system can allow the facility to lengthen the time based test intervals.

Some of the items that can be monitored are:

- Internal self diagnosis and alarming

- Voltage and current waveform sampling three or more times per power cycle and conversion of the samples to numeric values for measurement calculations by microprocessor electronics that are also performing self monitoring and alarming.

- Alarming for power supply failure.

- AC measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error.

- Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure.

- Alarming for change of settings.

The requirements and tests listed above pertain only to the protective relay. Communications systems, voltage and current sensing devices, station DC supply, control circuitry and other auxiliary systems that affect protection and control systems should also be tested.

Relay Alarming

One of the primary requirements for a protective relay to be considered as monitoring is that the relay has self-test diagnostics, be able to alarm for failure of those self-test diagnostics and also to be able to alarm for failure of the relay power supply. This is a critical function of the relay because failure of either self-diagnostics or failure of the power supply can prevent the relay from operating. Most microprocessor relays are equipped with a form-C contact, as shown in Figure 1 that is operated by a relay critical failure or loss of control power.
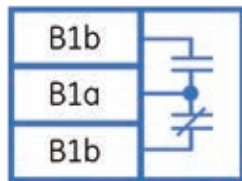

Figure 1. Critical Fail Contact

The contact in Figure 1 is shown in its shelf-state. Shelf-state would mean that the relay is un-powered, so the shown state is how the relay would appear failed. To truly monitor this system, the contacts to wire to an alarming device should be B1b-B1a. Wiring to B1b-B1a will give the receiving monitoring device a closed contact while the relay is healthy. Using a closed contact gives the alarming device the ability to not only monitor the relay health, but also the health of the alarm circuit, because if the circuit continuity is lost, an alarm is given. It is recommended to wire the self-test alarm contact to an adjacent relay and vice versa. This will allow the communicating relay to alert a digital control system of a failure of a neighboring relay.

In addition to the critical failure alarm, there are also several other non-critical alarms that need to be monitored. These alarms include: when a communication path is lost, when a remote IEC61850 device is "offline", when the IRIG-B time signal is lost, or when the relay is experiencing an unusually high ambient temperature.
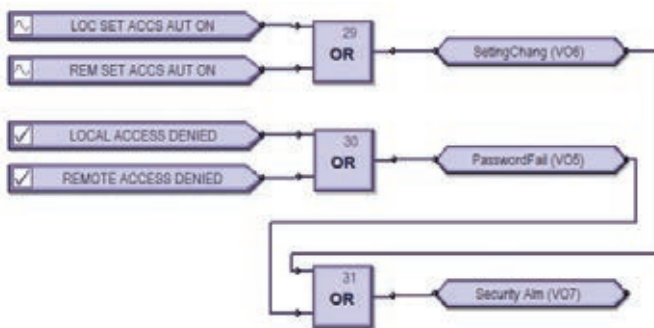

Figure 2. Security Alarm

Alarms should also be raised if settings are changed without authorization. This would allow an alarm to be generated if an employee changed settings in the wrong relay or if someone purposely changed settings to vandalize the protection and control system. Figure 2 illustrates an overall security alarm logic. In this logic the operand VO6 is asserted when a successful password has been entered and a setting is attempted. The operand VO6 could be mapped to an output contact or a communications point to raise an alarm for an attempted settings change. Additionally the operand VO5 is asserted when an incorrect password attempt is made on the relay. The combination of these two alarms could be used to raise a global security alarm for the relay.

ABILITY TO MONITOR THE PROTECTION AND CONTROL SYSTEM GIVES THE INDUSTRIAL FACILITY THE CAPABILITY TO CONTINUOUSLY INSURE THE HEALTH OF THE PROTECTION AND CONTROL SYSTEM.

Trip Coil, Close Coil, and Lockout Continuity Monitoring

The monitoring of the dc continuity of trip circuits, close circuits and lockout relay circuits use the voltage across the circuitry as shown in Figure 3. This can be accomplished by using a spare contact input of a relay or the internal voltage monitoring circuitry of an available relay output contact (shown as V) in the below Figure 3. Logic can be created to monitor the trip circuit when the breaker is closed and the close circuit when the breaker is open. No need of monitoring the trip circuit when the breaker is open nor monitoring the close circuit when the breaker is closed. For the trip circuit, the voltage monitor will be "on" or "Von" when the breaker is closed and indicates a healthy circuit. If the voltage is absent when the breaker is closed, an alarm will be given for a faulty trip circuit (i.e. "Voff"). For the close circuit, the voltage monitor will be "on" or "Von" when the breaker is open and indicates a healthy circuit. If the voltage is absent when the breaker is open, an alarm will be given for a faulty close circuit (i.e. "Voff"). Similarly an "open circuit" alarm can be created for the lockout relay circuitry (Figure 3) by monitoring the voltage across the circuit and alarming when the voltage is "off" or not present.
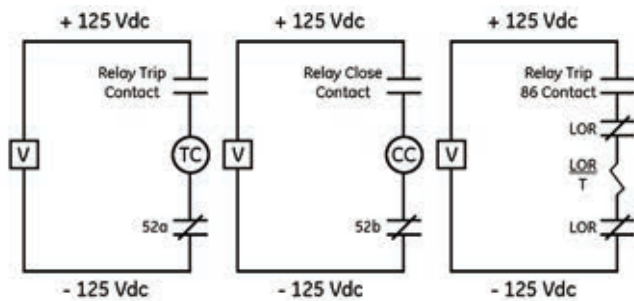

Figure 3. Trip, Close & Lockout Circuit Monitoring

Instrument Transformer Verification

Most critical protection systems have either redundant protective relaying or backup protective relaying. Typically, each set of relays is sourced from different instrument transformers. This type of redundancy is shown in Figure 4 where an "A" and "B" set relay protect each line. In this scheme, each relay is sourced from different three-phase current transformers. The "A" set relay could be configured to pass the RMS value of the current readings from the CTs that it is connected to, to the "B" set relay using an IEC61850 Analog GOOSE message and vice versa. The "A" and "B" set relays would use a comparator function to compare two RMS values and operate if the difference between the values is greater than a setting. The comparator could be used to raise an alarm if its RMS measured current is significantly different than the IEC61850 Analog GOOSE message it receives from the "A" set relay of RMS current. Since this is an alarm function, the time delay on the comparator could be set to accommodate any latency of the communication channel. These alarms would be blocked during fault conditions. This type of alarming should meet the requirement that the AC measurements are continuously verified by comparison with alarming for error or failure. This would also allow verification of correct CT and PT settings in each relay.
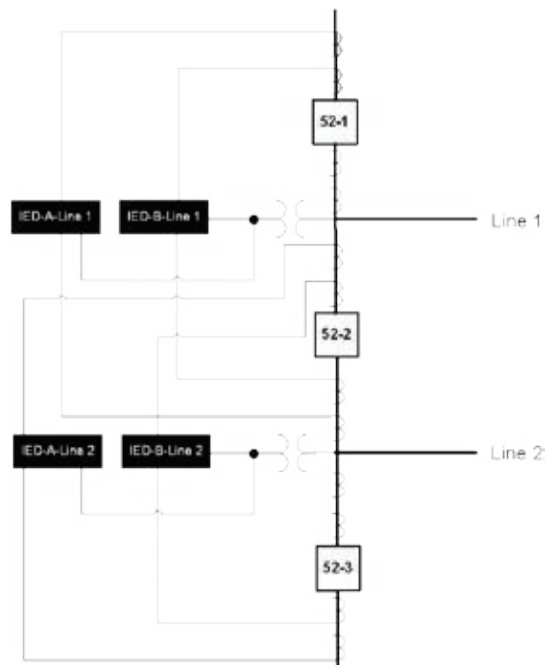

Figure 4. Breaker and a Half Scheme

Monitoring the potential transformers in Figure 4 presents a challenge since the "A" set and "B" set relays are both connected to the same potential transformers. In this instance, as long as the breaker 52-2 is closed, the voltage on the Line 1 relays should be the same as the voltage on the Line 2 relays. The Line 1 relays could send the RMS values of voltage to the Line 2 relays via an Analog IEC61850 GOOSE message. The comparator in the Line 2 relays could then be set to raise an alarm if the measured voltage values are different than the received RMS value (via Analog IEC61850 GOOSE) from Line 1 relay. These voltage comparison alarms would be blocked during fault conditions,

Breaker Restrike Detection

According to IEEE standard C37.100: IEEE Standard Definitions for Power Switchgear, restrike is defined as "a resumption of current between the contacts of a switching device during an opening operation after an interval of zero current of ¼ cycle at normal frequency or longer". The protective relay with its connected 3 phase currents can detect breaker restrike. An indication can be provided to the digital control system of the breaker restrike and logged by the relay for further analysis. Breaker restrike can be detected on several transmission applications, such as transmission line breakers, capacitor bank breakers and transmission breakers feeding large transformers. A typical restrike waveform and detection flag is shown in Figure 5.
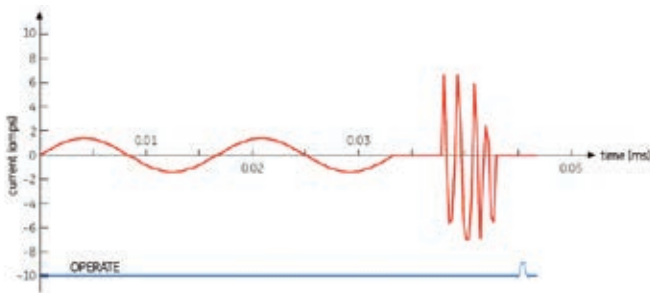

Figure 5. Typical Restrike Waveform and Detection Flag

MODERN MICROPROCESSOR BASED RELAYS PROVIDE OPPORTUNITIES TO UTILIZE MONITORING OF THE PROTECTION AND CONTROL SYSTEM TO REDUCE MAINTENANCE COSTS BY REDUCING MAINTENANCE TESTING.

The breaker restrike algorithm responds to a successful interruption of the phase current following a declaration of an open breaker. If a high-frequency current with a magnitude greater than the threshold is resumed at least ¼ of a cycle later than the phase current interruption, then a breaker restrike has occurred in the corresponding phase.

A restrike event is declared if all of the following conditions are true: (1) the current is initially interrupted, (2) the breaker status is open, and (3) an elevated high frequency current condition occurs and the current subsequently drops out again. A distinction is made between a self-extinguishing restrike and permanent breaker failure condition. The latter can be detected by the breaker failure function or a regular instantaneous overcurrent element. Also, a fast succession of restrikes will be picked up by breaker failure or instantaneous overcurrent protection

The user can add counters and other logic to facilitate the decision making process as to the appropriate actions upon detecting a single restrike or a series of consecutive restrikes.

Station Battery Monitoring

The protective relay can monitor the health of the station DC battery system. An analog indication of the current DC voltage derived from a contact input or dcMA transducer input wired between the positive and negative rails of the battery system can be provided to the digital control system and on the relay display. This signal can be used to generate high and low DC voltage station battery alarms.
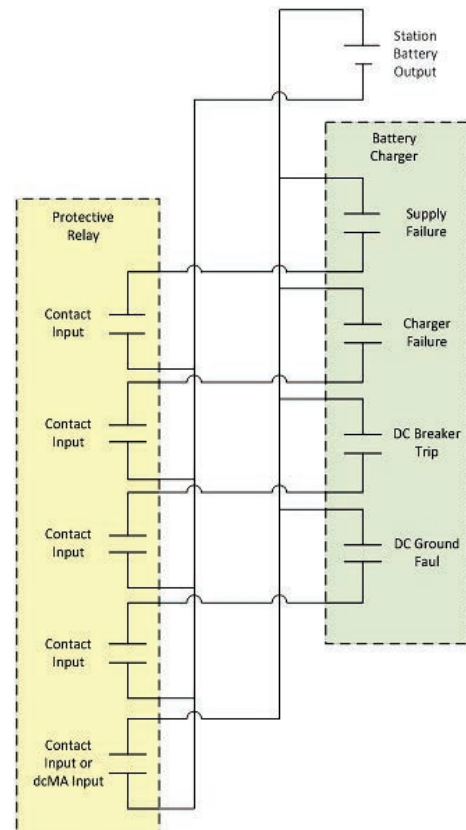

Figure 6. Station Battery Monitoring

A high dc voltage alarm can be configured to indicate the battery DC voltage is greater than a maximum value. This can result in loss of life, loss of electrolyte, and thermal runaway. The maximum value should be set above the expected voltage during an equalization charge.

A low dc voltage alarm can be configured to indicate the battery DC voltage is less than a minimum value. This can be a sign of the battery undercharging, which can lead to reduced cell capacity and sulfation. An undervoltage condition will also occur due to a charger failure.

The protective relay can monitor auxiliary alarm contacts from the battery charger system, such as:

- AC SUPPLY FAIL: Indicates the AC supply to the battery charger has failed.

- CHARGER FAIL: Connected to the charger critical failure contact and indicates the battery charger has failed.

- DC BREAKER TRIP: Indicates a DC distribution breaker has operated.

- DC GROUND FAULT: Indicates a battery DC ground fault.

The Sequence of Event (SOE) recorder of the relay can be used to record these alarms and the data logger of the relay can be used to record the station battery level or this value can be transmitted to the digital control system for display and recording. An example of the wiring for the station battery monitoring is shown in Figure 6.

Oscillography Cross Triggering

Modern relays have the ability to record oscillography data and event data inside the relay. One of the most useful methods of testing is to analyze operations of the protective system to insure that the protective system operated as intended and identify and correct near misses. This method can be referred to as "natural testing". When using redundant relaying of different manufacturer as in Figure 4, an inappropriate operation or inappropriate non-operation often only involves one of the relays. It is impossible to analyze the forensics in the non-operating relay if the oscillography is not triggered and oscillography is typically only triggered on a trip. Therefore, it is necessary to cross-trigger the oscillography, so that a trip in one relay causes all the relays in the station to also trigger oscillography (i.e. an "oscillography trip bus" or station digital fault recorder). This can be accomplished with contact outputs and a wired oscillography trigger, but a better implementation of this type of multi-cast message would be to cross trigger with IEC61850 GOOSE messages.

The event shown in Figure 10 is an example of analysis using cross triggering. This event comes from a transmission line with redundant relaying. In this event, the B and C phase CCVTs developed a problem and the B-C phase voltage presented

to the relay would have been zero. The "A" set relay operated appropriately, but not as intended since it was an undesired trip. With the voltages presented to the relay, the "A" set relay operated correctly. The "B" set relay did not operate for this event.
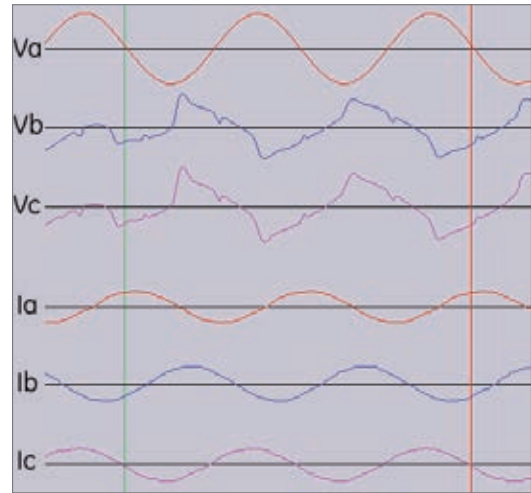

Figure 7. Cross Triggered Event

In the event of Figure 7, the "B" set relay was cross triggered and the event could be analyzed restoring confidence in the "B" set relay. The analysis revealed that the phase distance element was supervised by a current detector and the current level was not above the supervision level.

A second example of natural testing by event analysis is shown in the event record of Figure 8. This record comes from the transformer relay of a distribution substation where a trip on any feeder breaker triggers oscillography on the transformer differential relay. During this event, one of the distribution breakers tripped on a B-phase overcurrent. The transformer had a Delta to Wye phase conversion and analysis of the event shows the A-B phase current on the transformer primary was correct and the B phase current on the transformer secondary was correct. Additionally, the oscillography from the distribution relay could be merged with the transformer relay oscillography to compare the magnitudes and waveforms between the two relays. This analysis verifies the current transformer, CT circuits, and the relay current inputs.
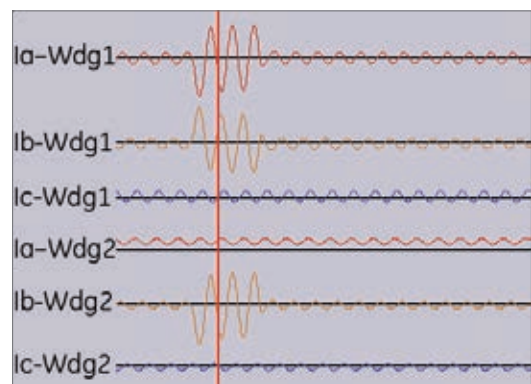

Figure 8. Transformer Event Record

Setting Comparison

Another beneficial software tool to the industrial facility is the comparison of settings in the relay "as found" to "as left". This comparison verifies settings are as specified" [3]. The function could be automated and provide an alarm if any settings have changed.

On-Line Real-Time I/O Verification

With the use of creative wiring and form C contact outputs of the relay, on-line real-time testing can be accomplished for critical or control relay contact outputs. Logic can be developed within the relay, to periodically test the actual working of an output contact and raise an alarm if the contact should fail. Protective relay trip and close outputs can be tested as shown in Figure 12 using the current coil monitoring of the relay output contact ("Ion"). For a trip circuit, logic can be developed to quickly connect the trip contact to DC battery negative through a resistance (such as 1000 Ohms) and energize the form C contact within milliseconds (within 2-4ms). If the contact is healthy, the current coil detector will operate (or "Ion"). If the contact does not close or is faulty, the current coil detector will not operate and an alarm can be issued. Similarly, logic can be developed for the relay close contact as shown in Figure 9.
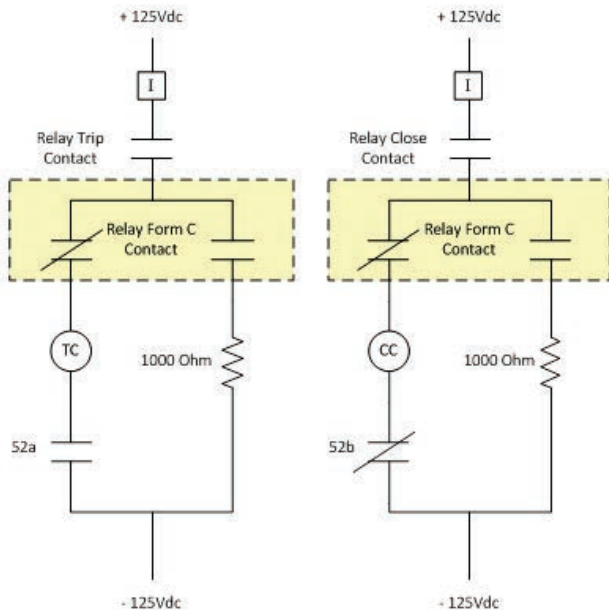
In addition, critical relay contact inputs, such as breaker failure initiate, start carrier, etc. can be on-line real-time tested by using form A contact outputs of the relay. Logic can be developed to quickly connect the critical input contact to the relay and test if it is recognized by the relay. Necessary functions that are normally affected by the tested input contact would be temporarily disabled during the short test period (2-4ms). Figure 10 shows an example of the wiring to automatically test a critical input contact of the relay using programmable logic. The relay could be temporarily put into "test mode" such that all relay output contacts are disabled temporarily during the input contact tests.
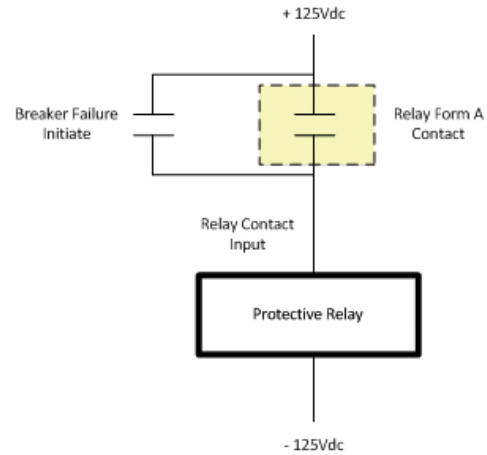

Figure 9. Real Time Testing of Critical Relay Contact Inputs

Figure 9. Real Time Trip & Close Relay Contact Output Testing

MONITORING THE PROTECTION AND CONTROL SYSTEM CAN ALLOW THE FACILITY TO LENGTHEN THE TIME BASED TEST INTERVALS.

Conclusions

The flexibility and configurability of today's microprocessor based protective relays allow an industrial facility to monitor the protection and control system and identify problems within the system before they manifest themselves by miss-operation. With the use of these monitoring techniques an industrial facility could lengthen the time intervals required for periodic testing of the protection and control system. The monitoring techniques include: trip coil, close coil, and lockout relay monitoring, usage of relay self-test alarm contacts, instrument transformer failure detection using analog GOOSE messaging & other level detection/comparison methods, breaker restrike detection, station battery monitoring, oscillography cross-triggering, and automated contact input & output testing. The relay sequence of event recorder (SOE) can be used to record the occurrence and time of these monitoring alarms of the protection and control system. In addition, these monitoring techniques increase the reliability of the protection and control system and enable the utility to have a smarter/intelligent protection and control system.

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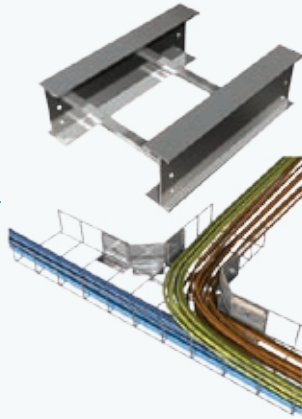
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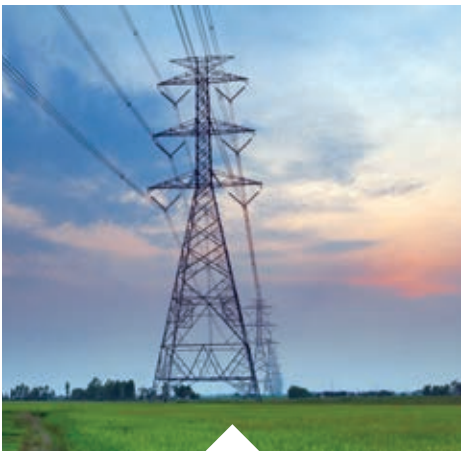
upcoming events

EDIST 2014

EDIST

Jan 15 - 17
Markham, Ontario, Canada
Hilton Suites & Conference
Exhibition Area

13th Annual Conference and Exhibition for Ontario's Local Electricity Distribution (LCD) companies.

www.edist.ca

DISTRIBUTECH 2014

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Jan 28 - 30
San Antonio, Texas, United States
Henry B Gonzalez Convention Center
Booth 1949

DistribuTECH is the utility industry's leading annual transmission and distribution event, covering automation and control systems, energy efficiency, demand response, renewable energy integration, advanced metering, T&D system operation and reliability, power delivery equipment, commercial and industrial energy management technology and water utility technology.

www.distributech.com

ENERGY GENERATION CONFERENCE 2014

ENERGY GENERATION CONFERENCE

Jan 28 - 30
Bismarck, North Dakota, United States
Bismarck Civic Center/Exhibit Hall
Exhibition Area

The 35th Annual Energy Generation Conference is a cooperative effort among producers, suppliers and educators to promote competitive, efficient and safe energy production.

info.bismarckstate.edu/ceti/energy

UTC REGION 8, 9 & 10 MEETING

UTC — UTILITIES TELECOM COUNCIL

Feb 3 - 5
Reno, Nevada, United States
Silver Legacy Resort
Exhibition Area

Every year, Regions 8, 9 & 10 get together to host the Utility Telecom Forum - their largest event. It provides utility telecom and IT professionals within the same geographic area the opportunity to get together and discuss similar challenges.

www.utc.org

IEEE IAS ELECTRICAL SAFETY WORKSHOP 2014

IEEE

Feb 4 - 7
San Diego, California, United States
Sheraton San Diego Hotel & Marina
Exhibition Area

The IEEE IAS Electrical Safety Workshop is focussed on accelerating the application of breakthrough improvements in human factors, technology and management systems that reduce risk of electrical injuries. Other goals include stimulating innovation in overcoming barriers, and changing and advancing the electrical safety culture to enable sustainable improvements in prevention of electrical accidents and injuries.

www.ieee.org

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Stockholmsmässan

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stockholm.ftthcouncil.eu

SOCIETY MINING, METALLURGY & EXPLORATION

Feb 23 - 26
Salt Lake City, Utah, United States
Salt Palace Convention Center
Exhibition Area

The Society for Mining, Metallurgy and Exploration is the world's largest society of minerals professionals. SME advances the worldwide mining and minerals community through information exchange and professional development at it's annual conference and exhibition.

www.smenet.org

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Nashville, Tennessee, United States
Music City Center
Booth 939

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www.techadvantage.org

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Booth 201

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www.powertest.org

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conferences.wsu.edu/conferences/calendar

POWER AND ENERGY AUTOMATION CONFERENCE (PEAC)

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Exhibition Area

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cm.wsu.edu/ehome/peac

upcoming events

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March 31 - April 4
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Bethancourt Ballroom, Student
Memorial Center, Texas A&M University
Campus

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prorelay.tamu.edu

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Jun 3 - 5
Amsterdam, The Netherlands
Renaissance Amsterdam Hotel
Hospitality Suite

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www.pcic-europe.com

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Apr 13 – 17
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The Gaylord National Resort and Convention Center
Exhibition Area

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cementconference.org

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Apr 14 – 17
Chicago, Illinois, United States
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Exhibition Area

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MOTOR PROTECTION PRINCIPLES & RELAYING		10-14			12-16	
DISTRIBUTION PROTECTION PRINCIPLES & RELAYING			3-5			24-26
F650 PLATFORM						
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8 SERIES PLATFORM						
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D20/D200 PLATFORM (D20MX)		3-7		28-2		
D25 RTU - GATEWAY	23-25				21-23	
D400 & RIO ESSENTIALS	29-31			22-25		
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MOTOR PROTECTION PRINCIPLES & RELAYING		10-12 English				16-18 English
DISTRIBUTION PROTECTION PRINCIPLES & RELAYING		3-5 English				9-11 English
F650 PLATFORM			10-12 English		26-28 English	
UR PLATFORM	15-17 English				7-9 English	

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D25 RTU - GATEWAY			10-14 English			9-13 English
D400 & RIO ESSENTIALS	13-17 English				5-9 English	
IEC 61850 SOLUTIONS			13-14 English		29-30 French	

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TRANSPORT X MAINTAINER			11-13 Lisburn & Rochester			
HYDRAN USER					13 Montreal	
HYDRAN MAINTAINER				16-17 Lisburn	14-15 Montreal	
TRANSFIX PLUS USER			19-20 Montreal			
TRANSFIX ZONE 2 MAINTAINER				16-17 Rochester		3-4 Lisburn
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