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Transmission & Distribution

The Electricity Forum

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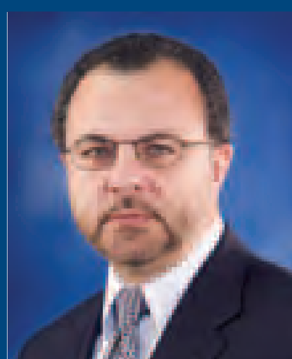
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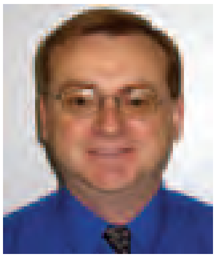
ONTARIO WANTS U.S. POWER, BUT NOT U.S. POLLUTION



By Don Horne

Washington is pushing for relaxed pollution controls on their coal-fired power plants, and the northeastern states and Ontario are anything but pleased with the prospect of more smog.

The objections lodged with the Environmental Protection Agency (EPA) by Ontario and 11 U.S. states (which includes New Mexico and Illinois) cite dirty coal-generation plants as a major contributor to smog.

The Canadian objection cites a 2005 provincial report "Transboundary Air Pollution in Ontario", that collected data on air pollution over the past 30 years. The report states that "imported air pollution" coming from the United States into Ontario costs that province $9.6 billion in economic damages (including $6.6 billion in health care costs). The report links 56 per cent of Ontario's smog-related deaths to U.S. air pollution.

Currently, there are 693 U.S. coal-fired plants sending smog into Ontario (of which 238 are more than 50 years old and 26 are of World War II vintage).

The American plan to relax pollution controls would lift emissions restrictions on the coal-fired plants within the next three to six months, allowing some plants to operate longer hours, thereby polluting more.

The coal-fired plants that Ontario is most concerned about are the ones operating in Wisconsin, Michigan and Minnesota, where the prevailing winds carry the majority of the emissions directly over the province.

Ironically, these states, and those states surrounding the Great Lakes, provide much of the electricity for Ontario's grid.

In fact, the ever-increasing purchases of American electricity by Ontario have contributed to the need for these same U.S. coal-fired plants to operate longer hours to meet the demand.

Ontario need look no further than its own backyard for how demand has outweighed environmental and health concerns, as they have pushed back the mothball date for their own coal-fired generation plants several years to avoid a catastrophic generation shortfall by 2010.

It is a tacit acknowledgement of the phrase, "the end justifies the means", but Ontario has found itself performing a split personality act - condemning the method of generation of the very power it so desperately needs.

The government of the day explains away this contradiction in terms by pointing to decades of sloth in failing to build new generation during the 1980s and '90s, and they are correct in saying so.

Public hearings on the construction of new nuclear generation have elicited a hue and cry from those attending, as citizens express their fears of nuclear fission technology. Unfortunately those who are first to take aim at nuclear are unable to provide viable alternatives to creating new significant generation, having rejected out-of-hand using coal or natural gas to create new generation. It goes to the very heart of Ontario's current electricity conundrum.

The northeastern United States have been on pace constructing new natural gas generation units during the 1990s, and they can confidently wag the finger of blame at those states still utilizing older coal-fired generation. Ontario's objections to relaxing restrictions on coal-fired generation are valid - but they ring hollow when their objections are underlined by requests for more electricity.

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NEW STANDARDS WILL GUIDE NETWORK TRANSMISSION OF AMR DATA

By Betsy Loeff

The latest addition to AMR-related technical standards is now written and moving through the final stages of industry adoption. Balloting has begun on the standard that will ultimately be called C12.22 by both Measurement Canada and the American National Standards Institute, or ANSI.

Also known as IEEE 1377 by the Institute of Electrical and Electronics Engineers, the new standard will govern network transmission of AMR data, says Lawrence Kotewa, staff engineer at the Community Energy Cooperative. Kotewa also heads AMRA's standards coordinating committee, which provides administrative and financial support to the IEEE and ANSI efforts. "This standard is key for mass AMR deployments," Kotewa says. "Its hardware-independent guidelines focus on AMR data and how to move it over both wired and wireless networks."

STANDARDS EVOLUTION

Standards are not new to the AMR industry. They've been under development since the early 1990s, when a small group of utility engineers and AMR vendors teamed up to form the first standards group focused on meter data and communications. Convened under the auspices of AMRA and IEEE, the group originally called its meetings "Table Fests" because they focused on creating data tables.

Soon, they formed a joint standards committee, run through IEEE, Measurement Canada and ANSI. The IEEE standards have different numeric designations than those published by MC and ANSI. Although these organizations work together, the standards they created are given different numeric designations by IEEE than the names shared by ANSI and MC. For simplicity's sake, this article will refer to standards by their ANSI numbers.

The first metering data standard developed, C12.19, also carries the nickname Tucker Tables, which is a nod of respect to Richard Tucker, president of Tucker Engineering Associates. When Tucker initiated AMR standards work more than a dozen years ago, he was a staff engineer at Duke Power. "I saw the pain," he recalls, explaining that back in the early days of AMR, every vendor had a proprietary way of writing and reading meter data. "It was massive confusion," he says. "The education we had to give our technicians and the mistakes that happened in the field had an atrocious cost."

Tucker remembers vendors telling him that he could get around the communications complications by going with a single source of meter technology. "My boss used to call that customer entrapment," he jokes.

Faced with choosing between complexity or single-sourced technology, Tucker decided to spearhead an effort to specify the common data tabular structures for meters and other utility functions such as load control and distribution automation. The result was C12.19, first published in 1997. It was followed by C12.18, which deals with communicating locally over an optical port, as meter readers do with touch-read systems. Next came C12.21, the standard to help utilities send data over telephone lines.

But engineers quickly realized that if they created transmission standards for all transmission media, they'd never get the standardization job done. "The next logical step was being able to move data across a network," says Kotewa, and that's what C12.22 does.

ADDED CLOUT

Tucker calls the nearly finalized standard a "powerful addition" to AMR technology development. "Without it, we didn't have a complete communications protocol suite," he says. Once this standard has been ratified for publication, some time in the first half of 2006, the AMR industry "will have all the lower layers of communication standardized, allowing utilities to take data such as a kWh reading all the way onto the wide area network, whatever the media used for the WAN," Tucker says. He adds that the WAN could be running on any medium: telephone, radio, Ethernet or something yet to come.

He also maintains that the completion of C12.22 will accelerate standards adoption and the development of future standards. According to Tucker, one of the "biggest offerings vendors bring to the metering world is their flamboyant ways to communicate and get the metering data back" to the utility head office. Once C12.22 is in place, "There will be no reason for vendors to spend so much money on proprietary protocols."

Of course, Tucker recognizes that even though vendors participate in standards development, standards have their downside for technology companies. "Standards bring the vendor's specialty item into the commodity market," he says, which potentially lowers prices by reducing product differentiation. On the other hand, "What happens to things once they're plug-and-play commodities? Markets expand. Standards will benefit vendors whether they know it or not," Tucker says.

UPCOMING UPGRADE

If standards developers have their say, C12.22 isn't the only AMR improvement headed to market next year. The standards groups have also been working on upgrades to C12.19 — the original Tucker Tables — and this time, the standard will cover one-way communication devices that broadcast a meter reading to a device upstream receiving the broadcast.

"Many utilities use AMR where, for example, you might have a van drive by and wake up the endpoint devices so they can spit out their meter reading and then go back to sleep," Tucker explains. "In

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ON-LINE DISSOLVED GAS ANALYSIS MONITORING

The purpose of this article is to provide insight and guidance on the selection of on-line dissolved gas analysis (DGA) monitoring and diagnostic tools for utility transformers. We'll examine transformers as utility asset classes in the context of their impact on revenue, grid stability, and service reliability.

TRANSFORMER FLEET RELIABILITY

Reliable energy flow is paramount and power transformers are critical, and costly, assets in the grid. As an asset class, transformers constitute one of the largest investments in a utility's system. For this reason, transformer condition assessment and management is a high priority. Each utility's grid is unique and investment levels in asset condition and assessment tools vary according to risk level and investment return models. While the models are different for each utility, the common element in them is that transformer fleets are stratified according to the criticality of individual transformers. The variability and uniqueness lies in where the prioritization lines are drawn and the investment amounts allocated for asset condition and management tools for each level. Typically, this approach has the most critical transformers receiving the highest investment of condition assessment and management tools and decreases for each less critical level identified.

An intentionally simplified model below shows one approach to transformer fleet stratification:

STRATIFICATION LEVELS

Critical – Those transformers that, if failed, would have a large negative impact on grid stability, utility revenue, and service reliability. GSUs and transmission transformers which are part of critical power flows are in this level.

Important – Those transformers that, if failed, would have a significant negative impact on revenue and service reliability. Transmission substation transformers and major distribution substation transformers are generally in this level.

Recoverable – Those transformers that, if failed, would have low impact on revenue and reliability. These are mainly smaller distribution substation transformers.

The relevance of transformer fleet stratification is more important today than in the past. Transformers don't last forever. In the US, with an average age of almost 40 years, many are now approaching the end of their design life. Higher loads placed on transformers - in a market that demands more electricity - have also taken their toll on transformer longevity. Compound this with the reduction in capital budgets and the need to more closely manage transformer assets becomes essential. Utilities can avoid unplanned failures, lower maintenance costs and defer capital expenditures through the appropriate use of transformer condition assessment and management tools. Applying the right tools for the situation is what stratification is all about.

Transformers don't last forever. In the US, with an average age of almost 40 years, many are now approaching the end of their design life.

THE EVOLUTION OF DGA

Monitoring the state of health of power transformers, a key component in the path of reliable power, has traditionally been carried out using laboratory DGA tests performed at periodic intervals. DGA of transformer oil is the single best indicator of a transformer's overall condition and is a universal practice today, which got started in earnest in the 1960s. The following is a brief summary of the recent evolution of the products and practice of DGA.

While laboratory or (somewhat recently) portable DGA has been the traditional practice, the use of on-line DGA tools has gained in popularity. The reason for this is the need for utilities to maintain or improve their reliability in the presence of decreased capital expenditures and an aging infrastructure. Something more than periodic laboratory or portable DGA is needed to be successful in the current environment and the two approaches (on-line DGA and laboratory DGA) now co-exist at many utilities. On-line DGA helps utilities avoid unplanned failures, adopt lower cost condition-based maintenance, and defer capital expenditures by extending the transformer's useful life.

First generation (1970s), as well as some current on-line DGA products available today, provide Total Combustible Gas (TCG) or single gas (Hydrogen) monitoring. These products provide indication of developing problems in the transformer but offer no legitimate diagnostic capability. On-line DGA offerings in the market have evolved from this early approach to include multi-gas monitors that detect and analyze some or all of the eight fault gases identified in the IEEE and IEC standards as well as provide diagnostic capability.

Newer on-line DGA products have the unique ability to continuously trend multiple transformer gases and correlate them with other key parameters such as transformer load, oil and ambient temperatures as well as customer specified sensor inputs. This capability enables utilities to relate gassing to external events, a key to meeting utility reliability and financial goals in the current envi-

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ronment. A study has also shown that some on-line DGA tools offer better accuracy and repeatability than laboratory DGA. This can improve the transformer asset manager's decision timeliness and confidence when incipient faults are detected.

With the advent of on-line DGA monitoring there has also been new learning about the nature of developing faults in transformers. On-line DGA monitoring has produced multiple case studies that document the development of critical faults, which could cause catastrophic transformer failure if left undetected, in timeframes from a few days to a few weeks. There is a low probability of capturing these rapidly developing fault conditions with a laboratory or portable-based transformer DGA testing program.

Recently, the ability to automatically populate traditional DGA diagnostic tools with on-line DGA data has appeared in the market. This new development offers users of on-line DGA monitors unprecedented insight into the nature and identification of developing faults. The tools are typically ratio-based and the on-line data set enables trending of fault gas ratios over time rather than the traditional static snapshots. Diagnostic outcomes can now be determined quickly and with more certainty than in the past. Neural network diagnostic approaches utilizing DGA data are also new to the market and promise more accurate diagnoses but have not yet been included in IEEE or IEC guides.

The next section will cover some of the decision criteria for employing on-line DGA tools.

SELECTING ON-LINE DGA TOOLS

The last few years have seen a new array of DGA tools enter the market and this poses challenges for utilities to understand and choose an approach that best meets their needs. Transformer asset managers have important decisions to make based on DGA information, including whether or not to take a transformer off-line in order to avoid a catastrophic failure. These decisions can significantly affect utility service reliability and revenue. The aging infrastructure and increasing electricity demand placed on existing transformer assets is exacerbating the problem. Higher loading on older transformers is causing faults that can lead to catastrophic failure to develop faster and more often. The transformer reliability bathtub curve shows that new transformers are not immune to failure either. This puts pressure on transformer asset managers to make critical reliability and revenue decisions more quickly and more often than in the past. Each transformer asset manager must choose the amount and type of transformer condition data they require for each level in their stratification model to make these big decisions. In response to this need the vendor community has brought out products that better support the asset manager's decision integrity by supplying more timely, accurate and certain transformer DGA data and diagnostic tools.

Table 1

Attribute	Number of Gases			
	8 Gas	3 Gas	2 Gas	1 Gas
Gases	All IEEE & IEC Fault Gases	CH_4, C_2H_4, C_2H_2	C_2H_2, H_2	H_2
Fault Coverage	*Best* All fault types detectable with DGA	*Better* Critical Faults: Partial Discharge, Arcing, Thermal Faults	*Minimal* Arcing, All other faults undetermined	*Poor* Indicates undetermined faults
Diagnostics	Supports all IEEE & IEC diagnostic tools	Duval Triangle (IEC)	Acetylene/ Hydrogen Ratio (IEC)	None
Price	Higher	Low	Low	Lowest

The increasing variety of on-line DGA tools, while helpful to the industry overall, presents transformer asset managers with the problem of matching the right product to their needs. A framework for decision making is required. The first step is a determination of a transformer fleet stratification model. For purposes of this paper, the stratification model discussed earlier will be used. To recap, the model has 3 levels of transformer assets identified; critical, important, and recoverable. In Table 1 above there is a list of attributes for various on-line DGA product categories relevant to on-line DGA tool selection. This list of attributes should be considered when applying on-line DGA to the various levels of a stratification model.

On-line DGA tools can be categorized by the number of gases they measure. The other attributes in the table are a direct result of the number of gases measured. Most modern on-line DGA tools offer the ability to measure other parameters such as moisture-in-oil. These other parameters are not included in the table as they are common for most offerings in the market today. Table 1 shows that the number of gases measured enables better fault coverage and diagnostic capability. These two attributes are critical decision criteria for the transformer asset manager. They define the extent of asset condition information available from the on-line DGA tool.

Fault coverage: is the number of detectable incipient fault conditions that the on-line DGA tool can support from its gas data. The fewer gases measured, the more fault conditions go undetected by the on-line DGA tool.

Diagnostics: is the capability of the DGA results to support the various diagnostic tools available in the IEEE and IEC guides. Once again, fewer gases measured mean fewer diagnostic tools available to identify fault modes.

Fault coverage and diagnostics are the critical attributes that transformer asset managers should consider when choosing on-line DGA tools for the various levels in their stratification models. Price is also a consideration but the rela-

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DGA

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tive value of the solution, as defined by the fault coverage and diagnostic capabilities, is the more important measure. In other words, some solutions may have a higher price but the value provided (through superior transformer condition knowledge) in terms of improved utility service reliability and revenue far outweighs the higher price.

Now, let's add the stratification model levels to Table 1, the on-line DGA tools/attributes table. This creates Table 2 which indicates the potential application of on-line DGA tools to our stratification model. This selection of on-line DGA tools for each level reflects the approach of making the highest investment in on-line DGA tools for the most critical transformers and less investment in tools for lower levels in the stratification model. Notice that this approach utilizes the on-line DGA tools with the most fault coverage and diagnostics for the critical and important transformers in the fleet. Utilities will find more appropriate returns on investment for their critical and important transformers with on-line DGA tools that offer good fault coverage and diagnostics capability rather than with the lowest cost, poor fault coverage tools that lack diagnostic support.

The current environment of higher loading on aging transformers, deferred capital expenditures as well as increased service reliability requirements suggests that utilities should take advantage of the improved on-line DGA offerings (i.e. better fault coverage and diagnostics) in the market to get the best protection for their biggest asset class – at all levels. Appropriate on-line DGA monitoring and diagnostic tools will help utilities avoid unplanned failures, lower maintenance costs and extend transformer useful life.

Table 2

	Number of Gases			
Attribute	8 Gas	3 Gas	2 Gas	1 Gas
Gases	All IEEE & IEC Fault Gases	CH_4, C_2H_4, C_2H_2,	C_2H_2, H_2	H_2
Fault Coverage	*Best*	*Better*	*Minimal*	*Poor*
	All fault types detectable with DGA	Critical Faults: Partial Discharge, Arcing, Thermal Faults	Arcing, All other faults undetermined	Indicates undetermined faults
Diagnostics	Supports all IEEE & IEC diagnostic tools	Duval Triangle (IEC)	Acetylene/ Hydrogen Ratio (IEC)	None
Price	Higher	Low	Low	Lowest
Stratification Model Levels	*Critical*	*Important*	*Recoverable*	
	GSU & Major Transmission Transformers	Transmission & Major Distribution Substation Transformers	Smaller Distribution Substation Transformers	

AMR data

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the first edition of C12.19, there was no provision to allow these kinds of devices to participate" in standardization efforts. He adds, "I stood on my soapbox and wore the group down" to include one-way devices in the next version of C12.19.

According to Tucker, this gives legacy one-way devices a way to have the data stream mapped into the formal data elements of C12.19, allowing for standards compliance without any change to the legacy devices. "New one-way devices will have the same flexible advantage," he says.

Both Tucker and Kotewa believe the new standards will give utilities more purchasing freedom, but only if the utilities themselves voice a preference for standards-compliant devices. "Utilities have to adopt standards and include those requirements in their bid specifications," Kotewa says. Will vendors balk? Perhaps, but as Tucker says, "The purchase order is what ultimately brings vendors to appreciate standards."


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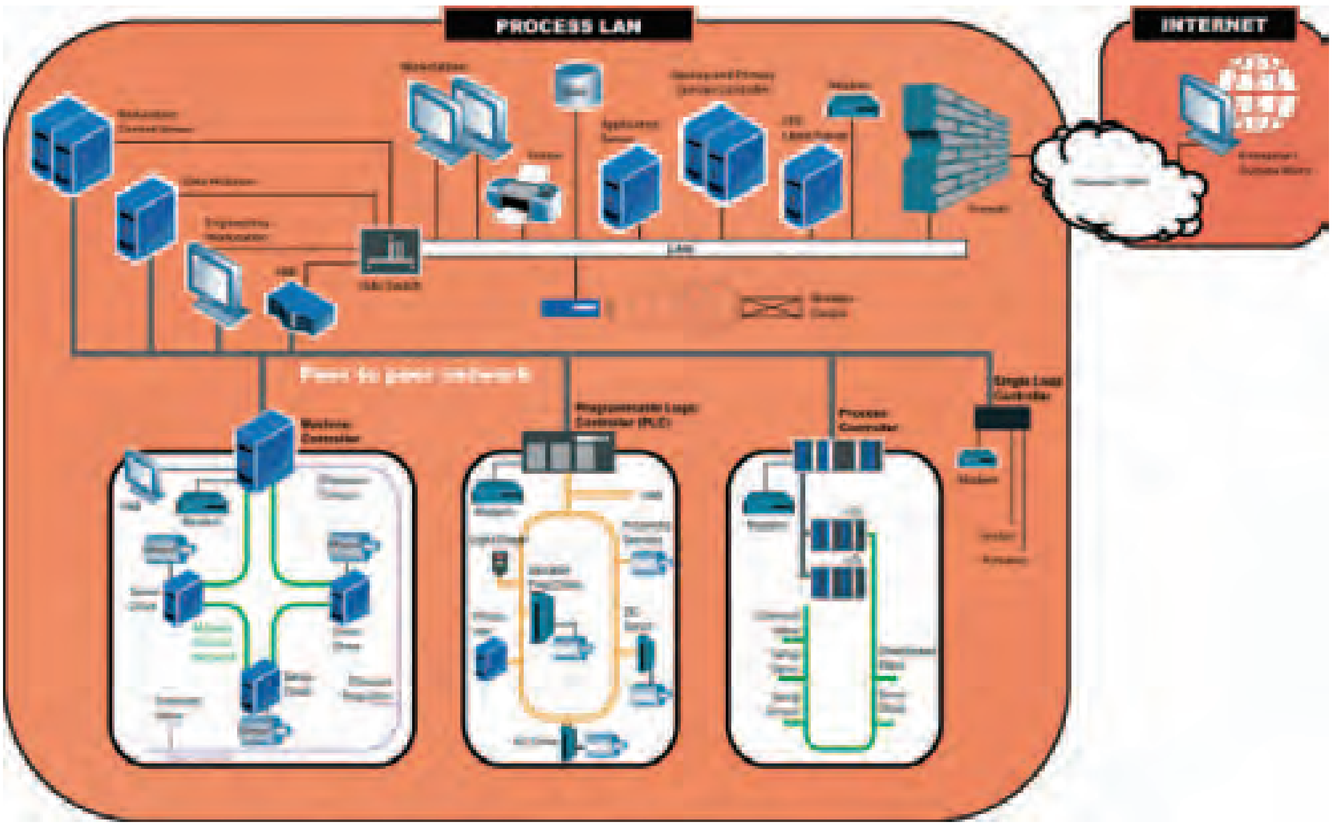
SCADA/BUSINESS NETWORK SEPARATION: SECURING AN INTEGRATED SCADA SYSTEM

By Scott Wooldridge



In recent years, utility companies have undergone great changes in the way they run their businesses. The pressure to increase profits and reduce expenses has them integrating their SCADA systems with their business networks to streamline operations. The popularity of the Internet has customers requesting online access to their accounts as well as online bill payment, further increasing network exposure. In addition, utility companies have reduced costs by leveraging the Internet to facilitate core business operations such as outage management and procurement.

The August 2003 mass power outage heightened public concern about the possibility of an intentional outage. As a result, North American Electric Reliability Council (NERC) created the Urgent Action Standard 1200. The purpose of this action was to ensure all entities responsible for the reliability of the bulk electric systems in North America identify and protect critical cyber assets that control or could impact the reliability of bulk electric systems. In 2004, NERC issued a continuation and update of Standard 1200 that remains mandatory for control areas and reliability coordinators. All control areas and reliability coordinators were to complete and submit the appropriate regional self-certification renewal form(s) indicating their degree of compliance or non-compliance with the cyber security standard requirements during the first quarter of 2005.

In addition, global terrorism has the public and media concerned about the security of public utility companies' critical infrastructure and their SCADA systems. Despite public fears, there is no reason for utility companies to shun the immense benefits resulting from the integration of SCADA systems and the advantages of the Internet. The threat may be real, but the measures to protect SCADA systems are, fortunately, relatively easy.

Perhaps the greatest danger to utility companies is the lack of awareness of the need for greater security. Many public and private companies controlling vital public utilities like gas, power and water, never thought they would be the target of cyber attacks and now must implement measures to improve network security. While many utility companies perform regular risk assessments of their SCADA systems, too many do not. They have become dependent on their tightly inte-

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grated digital information systems without fully understanding the potential impact of a cyber attack.

SCADA systems were traditionally "walled off" from other systems operating independently from the network. Prior to the awareness of possible attacks, this seemed to provide all the protection the SCADA system needed. They were largely proprietary systems with such limited access and esoteric coding that very few people would have the ability to access them to launch an attack. Over time, however, they became integrated into the larger company network as a means to leverage their valuable data and increase plant efficiency. Therefore, the reality is that their security is now often only as strong as the security of the network.

PROTECTING YOUR SCADA NETWORK

The first step towards securing SCADA systems is creating a written security policy, an essential component in protecting the corporate network. Failure to have a policy in place exposes the company to attacks, revenue loss and legal action. A security policy should also be a living document, not a static policy created once and shelved. The management team needs to draw very clear and understandable objectives, goals, rules and formal procedures to define the overall position and architecture of the plan.

Key personnel such as senior management, IT department, human resources and the legal department all should be included in the plan. It should also cover the following key components:

- Roles and responsibilities of those affected by the policy;
- Actions, activities and processes that are allowed and those that are not allowed;
- Consequences of non-compliance.

VULNERABILITY ASSESSMENT

A key aspect of preparing a written security policy is to perform a vulnerability assessment prior to completing the written policy. A vulnerability assessment is designed to identify both the potential risks associated with the different aspects of the SCADA-related IT infrastructure and the priority of the different aspects of the infrastructure. This would typically be presented in a hierarchical manner which, in turn, sets the priority to address security concerns and the level of related funding associated with each area of vulnerability.

For example, within a typical SCADA environment, key items and the related hierarchy could be as follows:

- Operational Availability of Operator Stations;
- Accuracy of Real Time Data;
- Protection of System Configuration Data;
- Interconnection to Business Networks;
- Availability of Historical Data;
- Availability of Casual User Stations.

A vulnerability assessment also acts as a mechanism to identify holes or flaws in the understanding of how a system is architected and where threats against the system may originate.

To successfully complete a vulnerability assessment, a physical audit of all the computer and networking equipment, associated software and network routings needs to be performed. A clear and accurate network diagram should be used to present a detailed depiction of the infrastructure following the audit.

After defining the hierarchy and auditing the different system components, the following areas of vulnerability need to be addressed, as they relate to each component, as part of the assessment process:

NETWORK AND OPERATING ENVIRONMENT SECURITY

- Application security;
- Intrusion detection;
- Regulation of physical access to the SCADA network.

It should also be understood when dealing with the SCADA infrastructure that there are commonalities and differences between SCADA-related IT security and IT security focused on typical business systems. For example, in a business systems environment, access to the server is typically the key focus. Whereas in a SCADA environment, the access focus is at the operator console level. This difference produces both alternate network topologies to provide the necessary availability, as well as a different focus on what elements of the SCADA system would be of highest priority to safeguard against security breaches.

FURTHER SECURITY MEASURES

As previously mentioned, SCADA networks were once separate from other networks and physical penetration of the system was needed to perpetuate an attack. As corporate networks became electronically linked via the Internet or wireless technology, physical access was no longer necessary for a cyber attack. One solution is to isolate the SCADA network; however, this is not a practical

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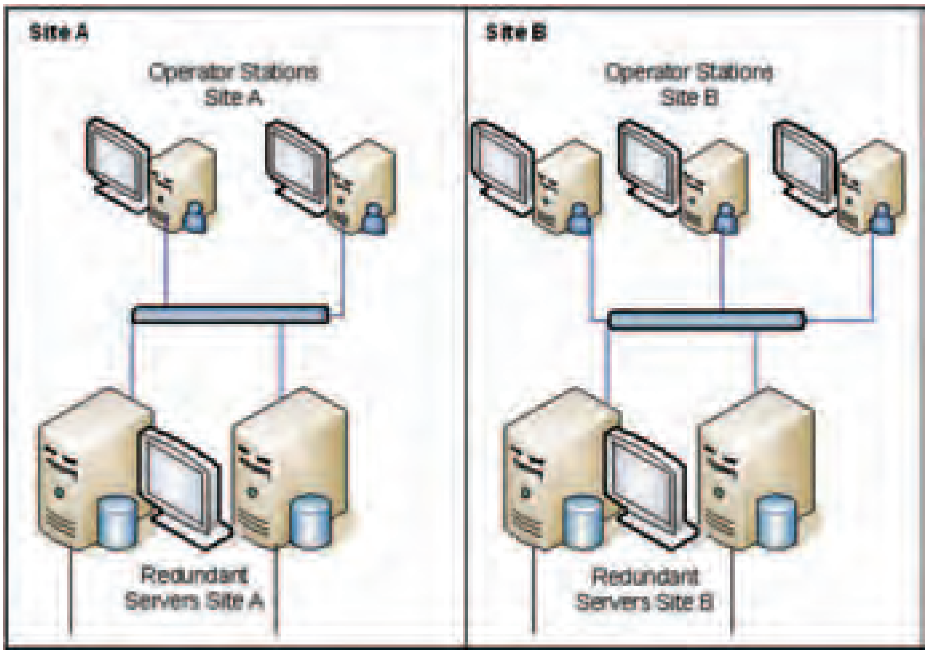

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solution for budget-minded operations that require monitoring plants and remote terminal units (RTU) from distant locations. Therefore, security measures need to be taken to protect the network, and some common security mechanisms apply to virtually all SCADA networks which have any form of wide area (WAN) or Internet-based access requirements. The core elements of each method are discussed in the following:

NETWORK DESIGN – KEEP IT SIMPLE

Simple networks are at less risk than more complex, interconnected networks. Keep the network simple and, more importantly, well documented from the beginning.

A key factor in ensuring a secure network is the number of contact points. These should be limited as far as possible. While firewalls have secured access from the Internet, many existing control system have modems installed to allow remote users access to the system for debugging. These modems are often connected directly to controllers in the substations. The access point, if required, should be through a single point that is password protected and where user action logging can be achieved.

FIREWALLS

A firewall is a set of related programs, located at a network gateway server that protects the resources of a private network from outside users. A firewall, working closely with a router program, examines each network packet to determine whether to forward it toward its destination. A firewall also includes or works with a proxy server that makes network requests on behalf of workstation users. A firewall is often installed in a specially designated computer separate from the rest of the network, so that no incoming request can get directly at private network resources.

In packet switched networks such as the Internet, a router is a device or, in some cases, software in a computer, that determines the next network point to which a packet should be forwarded toward its destination. The router is connected to at least two networks and decides which way to send each information packet based on its current understanding of the state of the networks to which it is connected. A router is located at any gateway (where one network meets another), including each point of presence on the Internet. A router is often included as part of a network switch.

It is imperative to utilize a secured firewall between the corporate network and the Internet. As the single point of traffic into and out of a corporate network, a firewall can be effectively monitored and secured. It is important to have at least one firewall and router separating the network from external networks not in the company's dominion.

On larger sites, the control system needs to be protected from attack within the SCADA network. Implementing an additional firewall between the corporate and SCADA network can achieve this aim and is highly recommended.

> It is important to have at least one firewall and router separating the network from external networks not in the company's dominion.

FIREWALL DESIGN FOR A SCADA NETWORK

Virtual Private Network (VPN)

One of the main security issues facing more complex networks today is remote access. VPN is a secured way of connecting to remote SCADA networks. With a Virtual Private Network (VPN), all data paths are secret to a certain extent, yet open to a limited group of persons, such as employees of a supplier company. A VPN is a network constructed by using public wires to connect nodes. For example, there are a number of systems that allow the creation of networks using the Internet as the medium for transporting data. These systems use encryption and other security measures to ensure only authorized users access the network and data cannot be intercepted. Based on the existing public network infrastructure and incorporating data encryption and tunneling techniques, it provides a high level of data security. Typically a VPN server will be installed either as part of the firewall or as a separate machine to which external users will authenticate before gaining access to the SCADA networks.

IP SECURITY (IPSEC)

IP Security (IPsec) is a set of protocols developed by the Internet Engineering Task Force (IETF) to support the secure exchange of packets at the IP layer. IPsec has been deployed widely to implement VPNs.

IPsec can be deployed within a network to provide computer-level authentication, as well as data encryption. IPsec can be used to create a VPN connection between the two remote networks using the highly secured Layer Two Tunneling Protocol with Internet Protocol security (L2TP/IPSec).

IPsec supports two encryption modes: Transport and Tunnel. The Transport mode encrypts only the data portion (payload) of each packet, but leaves the header untouched. The more secure Tunnel mode encrypts both the header and the payload. On the receiving side, an IPSec-compliant device decrypts each packet.

For IPsec to work, the sending and receiving devices must share a public key. This is accomplished through a protocol known as Internet Security Association and Key Management Protocol/Oakley (ISAKMP/Oakley), which allows the receiver to obtain a public key and authenticate the sender using digital certificates.

It is important during the selection process of network hardware such as routers, switches and gateways to consider the inclusion of support for IPSec security as part of the devices to enable the support of secure VPN connections.

DEMILITARIZED ZONES (DMZ)

Demilitarized Zones (DMZ) are a buffer between a trusted network (SCADA network) and the corporate network or Internet, separated through additional firewalls and routers, which provide an extra layer of security against cyber attacks. Utilizing DMZ buffers is becoming an increasingly common method to segregate business applications from the SCADA network and is a highly recommended additional security measure.

APPLICATION SECURITY

In addition to securing the network, securing access to SCADA system components will provide a further defense layer.

Authentication is the software process of identifying a user who is authorized to access the SCADA system. Authorization is the process of defining

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access permissions on the SCADA system and allowing users with permissions to access respective areas of the system. Authentication and authorization are the mechanisms for single point of control for identifying and allowing only authorized users to access the SCADA system, therefore ensuring a high level of control over the system's security.

To provide effective authentication, the system must require each user to enter a unique user name and password. A shared user name implies a lack of responsibility for the protection of the password and any actions completed by that user.

It must be possible for user names to be created, edited and deleted within the system while the system is active to ensure individual passwords can be maintained. In addition, it is highly recommended that password aging be implemented. Password aging ensures that operators change their passwords over a controlled time period, such as every week, month, and so on.

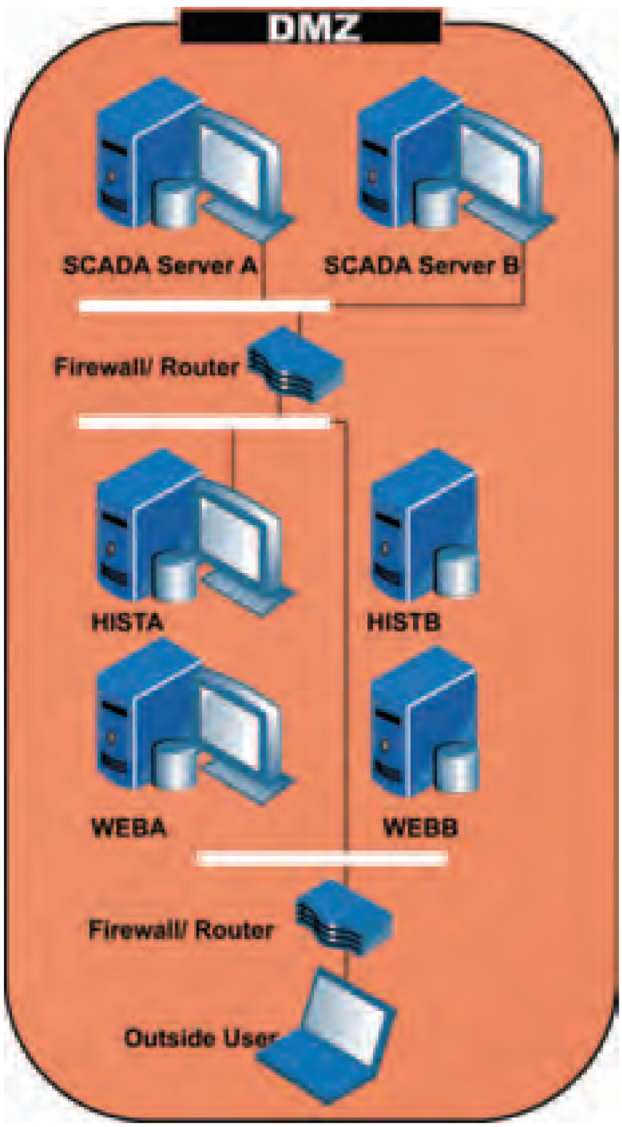
To provide authorization, the system must be able to control access to every component of the control system. The system must not provide a "back door" by which to bypass the levels of authentication specified in the application.

Critical data pertaining to a SCADA system must be securely stored and communicated. It is essential that critical data like a password be stored using an encryption algorithm. Similarly, remote login processes should use VPNs or encryption to communicate the user name and password over the network.

Critical data like user name and password must be persisted in a secured data repository and access rights monitored and managed using secured mechanisms like Windows authentication and role-based security. It has become common practice for SCADA systems operating in the Windows environment to utilize Windows Domain security to maintain user profiles. This is a recommended approach as it centralizes security and administration while providing an acceptable audit trail of user actions.

AUDIT TRAILS

It is recommended that Audit trails on critical activities like user logins, changes to operational parameters or changes to system access permissions be tracked and monitored at regular intervals. Securing your SCADA application may make it more challenging for external hackers to gain control of the system; however it will not prevent internal sabotage. Regularly tracking and monitoring audit trails on critical areas of your SCADA system will help identify suspicious activities and consequently allow the necessary corrective actions.



WIRELESS NETWORKS

The two most common ways of gaining unauthorized access to a wireless network are by using an unauthorized wireless client, such as a laptop or PDA, or by creating a clone of a wireless access point. If no measures have been taken to secure the wireless network then either of these methods can provide full access to the wireless network.

Many commercial wireless networks are available, which range in price, complexity and level of security provided. When implementing a wireless network, a couple of standard security measures can minimize the chance of an attacker gaining access to the wireless network.

Approved clients – The access points in the wireless network contain a configurable list of all MAC addresses of the authorized clients that are permitted access to the wireless network. A client not listed in an access point cannot access the wireless network.

Server Set ID (SSID) – This is an identification string that can be configured on all clients and access points in your wireless network. Any client or access point participating on the wireless network must have the same SSID configured. The SSID is, however, transmitted as a readable text string over the network. Therefore, an SSID alone is not sufficient to secure the wireless network.

Wired Equivalent Privacy (WEP) – All clients and access points should have a configurable static WEP. This is a 40, 64 or 128-bit encryption string that is entered in all clients and access points. Without a correct WEP string, no access can be gained to the wireless network. The SSID is also encrypted using this string. In most cases, using an SSID and a WEP provides a secure solution.

802.1X EAP (Extensible Authentication Protocol) – WEP is the minimum level of security recommended for wireless client access. The disadvantage with WEP is the management of the network strings. It is possible to decode these, and updating to new keys is a man-

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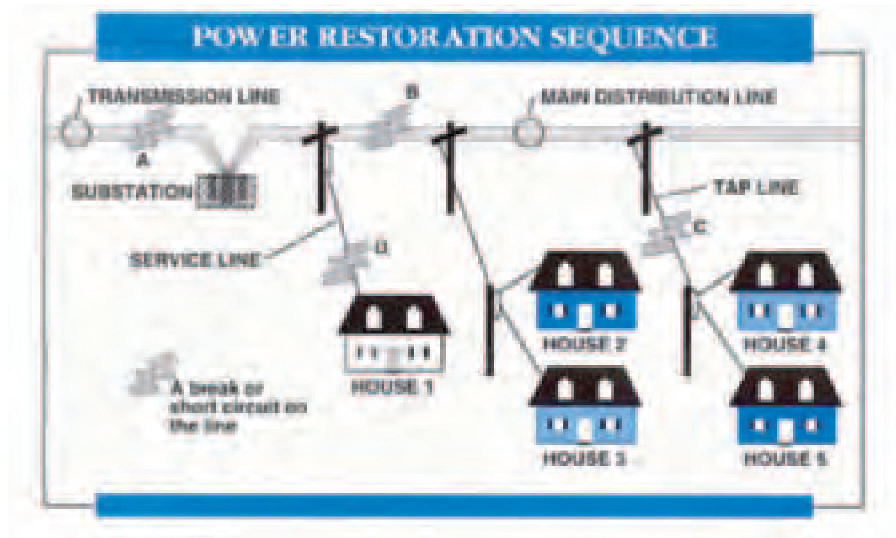
OUTAGE MANAGEMENT: AN ELECTRIC UTILITY'S NUMBER ONE HEADACHE

A system outage is a crisis that is always just around the corner for an electric utility., The utility provides a critical service that demands a high degree of reliability, but which is only really noticed when it becomes unavailable in an outage. At the moment of crisis, all eyes turn to the utility as it works to restore power. It is a very stress-filled situation.

Typically, stormy weather is the cause of disruptions to the physical electric grid that result in an outage. It is always an unplanned event and there is always pressure to restore service as soon as possible.

Less frequently an outage caused by a short-circuit to the grid, should a tree branch or other object happen to make contact with a power line and connect it to the ground. Thus, basic utility outage management is a time-tested routine of system maintenance via tree trimming programs and outage recovery planning and drills meant to ensure that utility personnel are prepared and well trained in the event of an emergency outage.

In an outage situation, it is critical for utility personnel to communicate with ratepayers, immediately isolate which circuits are down, pinpoint the cause of the outage, fix the problem, restore service, and communicate with ratepayers. An outage situation is one of the most bedeviling issues that utilities face: not only is it a difficult issue from a perception and public relations perspective, but it also results in lost revenue when the electricity is not flowing, and depending on the extent of the outage, the amount of revenue lost can be considerable. Accordingly, in the details below, note the importance of utility-ratepayer communications at the beginning and end of the process, communications between utility personnel during outage restoration, and access to system data throughout. Voice and data communications are vital components of a successful outage restoration, and the communications infrastructure thus plays a critical role in outage detection, notification, and recovery.



New wireless broadband network technology such as the mesh router system by Tropos Networks provides a utility with a valuable new tool to address this traditional utility management headache and customer service crisis point. With such a new tool, an entirely new perspective on outages becomes possible, and that's the focus of this whitepaper.

THE CURRENT ROLE OF TELECOMMUNICATIONS IN OUTAGE MANAGEMENT SCENARIOS

The role that communications technology currently plays in an outage event is partly analog, partly digital, as follows:

1. Outage Realization / Outage Detection

a.) The SCADA1 System notifies the Energy Control Center (ECC) that a breaker is open and that an outage has occurred OR the affected customers telephone the utility call center or their key account representatives when they experience an outage. In the case of a significant outage with more incoming call volume, an automated call intake process is triggered. Data for outage addresses is generally logged manually or by the system. In some instances, an estimate for system restoration is provided.

b.) Key Account customers often have a separate call-in number to ensure that special attention is paid to them in the event of an outage.

A few outages are caused by a short-circuit with ratepayers. An outage situation is one of the most bedeviling issues that utilities face: not only is it a difficult issue from a perception and public relations perspective, but it also results in lost revenue when the electricity is not flowing.

2. Outage Data

a.) The address data for outages derived from outage calls and/or SCADA system data is fed into an electronic database, which triggers special software to analyze the event and makes an estimate on probable cause, i.e., which distribution circuits and/or devices are out. In the case of key accounts, the data may be logged based on the feeders that align with each key account.

3. Outage Discovery

a.) Using the special power outage software and estimated outage areas, the control center dispatches field crews to visually inspect the outage area, analyze the situation, and confirm a cause for the event.

b.) Field crews communicate via voice with the Control Center using mobile radios and use laptops with access to preloaded utility distribution infrastructure data that employs a GIS application. If this data is in error or outdated, the crew will need to call the control center, in lieu of returning to the office, to get more accurate data.

c.) After a field inspection, field crews are able to provide a better estimate and time for system recovery – "estimated time of recovery" or "ETR" – and communicate that verbally back to the control center, which becomes the resource for any future estimates on recovery. To ensure good coordination, the control center will generally update the Call-Taking Application (CTA), which will provide an update for Customer Care and Key Account personnel.

4. Outage Recovery

a.) Outage recovery is a delicate process that requires extensive coordination between the control center and the field. With damage and cause assessed, the crews make plans for restoration by order of priority, working on main lines first and then on remote feeders, and finally to individual accounts that still lack power.

b.) Field crews make necessary repairs to restore the system, after having identified needed repairs and addressed the cause of the outage.

c.) The control center updates the outage management application with the new information on outage cause, times, etc.

d.) Customer Care and Key Accounts call the customers to confirm that power is back on, which is generally routine, but also serves as a check in the case where power has not been fully restored and certain accounts remain out.

e.) If power is discovered to still be out for particular accounts, that information is communicated back to the control center and out to the field crew, who focus on addressing the remaining outage issues.

THE POTENTIAL ROLE OF ADVANCED TELECOMMUNICATIONS IN OUTAGE MANAGEMENT SCENARIOS

The review above of the outage identification, management, notification, and restoration processes provides insights into possible avenues for process improvement with a communications network based on the Tropos wireless mesh equipment. When combined with special wireless equipment like wireless laptops, PDAs, and VoWiFi handsets, as well as field sensors like an AMR system, the Tropos wireless mesh network becomes a vital tool for the utility in recovering from an outage, as detailed below.

1. Outage Realization / Outage Detection

a.) AMR meters as a "trip wire" system. For those utilities that have an AMR system, the meters can act as a trip wire to indicate the loss of power at an end point. The smart meters can be programmed to give a "last gasp" message that they have lost power, providing the utility with pinpoint accuracy on the power outage. The AMR system uses the wireless network to push messages back and forth to and from the field.

b.) Communication between the control center and field crews. Because such communication is currently based on radio traffic and verbal communications that indicate routing of the crew, slower response times are a significant risk.

Improved communication with wireless laptops, PDAs and VoWiFi handsets would facilitate reprioritization and rerouting of field crews in a dynamic outage scenario.

2. Outage Data

a.) Data v. Voice Communication. Moving to more reliance on integrated data communications over the wireless network, with automated updates based on dynamic situational data, should result in improved response times as well.

b.) Circuit data systems. GIS system relies on static data and does not always present a true picture of actual system status (for instance, work on a distribution substation may cause power to flow differently). On the other hand, outage management software relies on near real-time, dynamic data. The discrepancy between these two systems can be a potential cause of confusion. Working to leverage a wireless broadband communications network to integrate field and enterprise data could make the difference between a rapid, successful outage recovery and a problematic outage recovery.

3. Outage Discovery

a.) Communication back from the field to the control cen-

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AN UPDATE ON TEST EXPERIENCES WITH SHORT-CIRCUIT WITHSTAND CAPABILITY OF LARGE POWER TRANSFORMERS

By R. P. P. Smeets, L. H. te Paske,
KEMA High-Power Labs

ABSTRACT

Experience is reported of short-circuit testing of large power transformers during the past 9 years by KEMA in the Netherlands. In total, 62 transformers > 25 MVA participated in the survey.

KEMA shows that at initial access to standard IEC short-circuit tests, 30% failed initially in case of a wide range of power (62 transformers 25 - 440 MVA tested). During the past 5 years, almost all of the initial failures were observed at the upper end of both voltage and power.

No clear single cause for major failures could be identified; instead, a variety of defects was observed, mostly because of the dynamics associated with passage of short-circuit current. It is the author's observation that change in winding impedance due to short-circuit current passage is an excellent indicator for the short-circuit withstand capability.

The authors comment on often heard considerations to replace short-circuit testing by design review procedures, mainly because of costs:

"There is no necessity to test because calculation methods are sufficiently adequate."

"There is no necessity to test because service experience with transformers is so good."

"The costs of testing have become prohibitively high and testing takes too much time."

"Short-circuit testing may have a deteriorating influence on the transformer under test."

The authors conclude that design review, as the only component of quality assessment of power transformers, is not sufficient since 1/3 of the transformers that failed in service underwent design review alone. No transformer failed in service had been short-circuit tested prior to installation. In addition, it is demonstrated that a major leap in quality improvement could be realized through full-power testing.

It is concluded that although statistically every transformer faces several full short-circuits during its life, the current that really occurs at such a full short-circuit current is smaller than the rated short-circuit for which the transformer is designed. In the future, however, this gap will narrow due to more efficient utilization of the networks and growth of energy consumption.

A brief overview is given on test methods and test installations of the author's laboratory.

With an increase of the short-circuit power during the years, the most severe short-circuit currents will appear when the transformer is aged.

1. INTRODUCTION

The effects of short-circuit currents in transmission and distribution networks for electric energy are tremendous, both for the equipment and for the stability of the networks. Since short-circuits occur quite often, the short-circuit withstand capability is regarded as belonging to the main characteristics of the equipment installed. Transformers, like series reactors, have the ability to limit the short-circuit currents to values predominantly determined by the transformer's impedance.

In this way, the design of a power transformer with respect to the short-circuit current withstand capability is focused towards the limitation of short-circuit current.

In addition, the control of the forces and stresses exerted by the same short-circuit currents inside the transformer must be an integral part of the design process. With an increase of the short-circuit power during the years, the most severe short-circuit currents will appear when the transformer is aged. These short-circuit currents have to be withstood without impairing the transformer. Short-circuit withstand capability should also cover the ability to withstand several full asymmetrical short-circuit currents in each phase and in each representative tap position without impairing the transformer suitability for normal service.

Experience with short-circuits in service as well as with short-circuit tests in high-power laboratories forces users and manufacturers to pay serious attention to the short-circuit withstand characteristics of power transformers.

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ter and to the Call Center. With mobile data enabled by a wireless system, field crews can file estimated times of restoration (ETRs) immediately upon visual inspection.

Waiting for data or attempting to access data without the benefit of broadband speeds can slow down recovery times considerably.

4. Outage Recovery

a.) Communication between the field and the control center and the Call Center. Field crews make final inspections and provide assurances of power restoration back to the control center. Often, field crews may discover after returning that one or more customers still do not have power restored. Such individual restoration as a last step is greatly facilitated when field crews have immediate communication with customer account representatives.

CONCLUSION

Management of any distributed infrastructure is greatly facilitated with the combination of processes, solutions, equipment, and manpower that is enabled by a ubiquitous wireless broadband network that overlays the infrastructure. Such a system consists of digitally automated processes, high-powered computers, specialized software applications, mobile communication gear, an integrated wired/wireless broadband network, and highly skilled crews. The critical component, the broadband network, is now available to utilities to an extent that it was never available before, thanks to affordable and highly capable wireless technology.

Tropos enables such a system to come to life, resulting in improvements that are most noticeable in a crisis situation like a power outage. When every second counts, it pays to have the best that technology can provide, and these days, that means a wireless broadband mesh network powered by Tropos gear.

ENDNOTES

1 SCADA – (Supervisory Control and Data Acquisition) system used to control distributed systems from a master location, with most operator interaction driven by alarms, which automatically detect abnormal conditions, and may require operator intervention (mostly used for high-voltage transmission systems).

...you said it

Our readers have written in to say…

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"I have received your magazine for a number of years when employed as a maintenance director (electrician); I am a director of our local LDC (Goderich Hydro) and hope to continue to receive your excellent publication. Thanks."

test experiences

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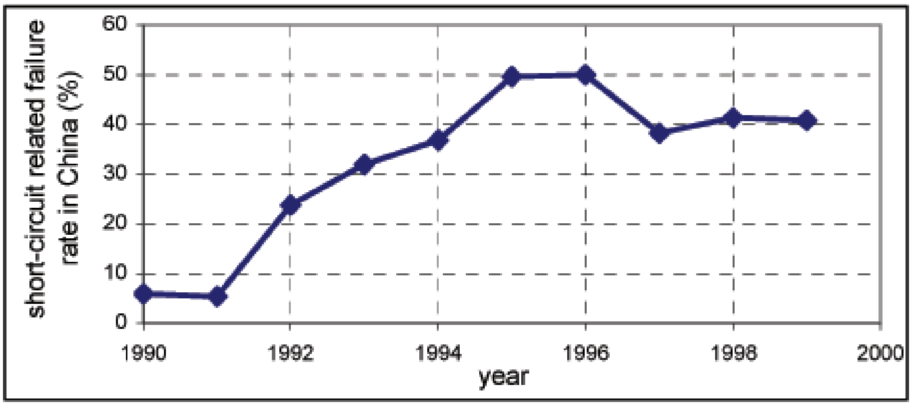

/Fig. 1: Transformer failure rate in China due to short-circuit

One of the methods for purchasers to assess the short-circuit current withstand capability of transformer is to conduct a design review, based on calculation results only. Recently, CIGRE issued guidelines on this method.

In the present contribution, some limitations of this method will be explained, as well as the possibilities to achieve a higher degree of reliability with respect to short-circuit withstand capability through full-scale testing in accordance with the international standards.

Recent experiences of KEMA High-Power Laboratory, world market leader in independent short-circuit testing of HV equipment, are presented.

2. SHORT-CIRCUIT STRESSES IN THE WINDINGS

By means of all the short-circuit currents calculated for the different network conditions the electrodynamic stresses can in principle be determined.

The electrodynamic forces are proportional to the vector product of the current in a conductor and the magnetic induction at that location. The magnetic induction in and between the coils of a winding is varying in the radial direction as well as in the axial direction of the windings.

Also, from the centre of the coils towards the ends of the coils, the direction of the magnetic induction is varying from predominantly axial to predominantly radial, influencing in this way the radial and axial stresses. The magnitude of the leakage fluxes is dependent on the currents and current directions in the different coils forming one phase. Such coils are for instance the coils forming one or two LV-windings, the HV-windings, the tapping windings and the compensation windings (when applied).

The electrodynamic forces appear in the radial direction (pushing the inner core inwards and the outer coil outwards) and in the axial direction (with a pulsating compression force). Related to the conducting material the forces can be translated into stresses: radial stresses and tangential stresses of a tensile or compressive nature. The stresses then can be compared with the material's characteristics in order to judge the probability of over-stressing the conductors and its supports.

The electrodynamic stresses are varying in time and spatially. By means of simplifications it is possible to calculate approximately the highest stresses that occur.

The simplifications are: disregard of the influence of the other phases on the magnetic fields in a certain winding, calculate the forces and stresses for the current peaks and RMS values only, consider the windings as rigid (i.e. without any flexibility or settling effects), consider the coils as circular symmetrical, etc. The most onerous circumstances can be selected by such calculations and simulations.

The transient mechanical behaviour of the windings (natural frequencies, damping, non-linear effects) and the production tolerances (tolerances in materials, processing, assembling, etc.) make it very complicated to exactly simulate the winding's behaviour. At the design stage extra margins are implemented to cover such effects.

The calculation of the stresses and the margins with respect to the critical stresses is a specialty of the manufacturer. The experience with such calculations and the experience with real short-circuit tests have to build the manufacturer's basis for designing power transformers with a well defined short-circuit withstand capability.

3. REQUIREMENTS IN THE STANDARDS

The important diagnostic tests are the routine tests before and after the short-circuit tests, the measurement of the transformer's reactance after each successive full test, the behaviour of the Buchholz-relay, the measurement of abnormalities in the currents (including tank current) and voltages during the short-circuit tests.

KEMA's experience with vibration measurements, FRA-measurements, excitation current measurements, etc. is that these techniques give no conclusive answer to the question whether or not the transformer passed short-circuit tests. On the other hand the much simpler reactance measurements after each short-circuit test form a more accurate indicator for the transformer's behaviour during the tests, and is often the basis for the decision to continue testing or not.

Another criterion is the visual inspection of the transformer's active part after the short-circuit tests. To make this possible, the active part has to be untanked.

Depending on the variation of the transformer's reactance (larger than for instance 1% or showing a progressive tendency), the outcome of the routine measurements and the first impression after untanking, a further dismantling of the active part may be necessary for a detailed inspection.

Such inspections, especially when a further dismantling is necessary, can best be carried out at the manufacturer's site where all expertise and tools are available. Mostly the routine tests are performed at the manufacturer's laboratory as well. KEMA's experts are present during the routine tests and inspections. As stated in the IEEE standards, also in the IEC 60076-5 standard the dielectric routine tests have to be repeated with 100% values.

4. SHORT-CIRCUIT TESTING VS. VERIFICATION BY CALCULATION TOOLS

Discussions on the pros and cons of short-circuit testing can be summarized

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ual process. EAP is a relatively new standard that dynamically alters keys while providing built-in authentication requirements. It is recommended where possible EAP authentication is enabled for wireless devices.

VPN (described earlier) was developed to provide secure connections through the Internet to internal corporate networks. A VPN simplistically creates a secure tunnel through open networks such as the Internet or a wireless network. Data transmitted through the tunnel is encrypted on the client then decrypted and validated in a VPN gateway inside the wireless access point. VPN is a single solution providing security both for the wireless and wired network, thus reducing implementation and maintenance costs.

INTRUSION DETECTION

Firewalls and other simple boundary devices currently available lack some degree of intelligence when it comes to observing, recognizing and identifying attack signatures that may be present in the traffic they monitor and the log files they collect. This deficiency explains why intrusion detection systems (IDS) are becoming increasingly important in helping to maintain network security.

In a nutshell, an IDS is a specialized tool that reads and interprets the contents of log files from routers, firewalls, servers and other network devices. Furthermore, an IDS often stores a database of known attack signatures to compare patterns of activity, traffic or behavior it identifies in the logs it monitors against those signatures. There are various types of IDS monitoring approaches:

Network-based IDS characteristics – A network-based IDS monitors an entire, large network with only a few well-situated nodes or devices and impose little overhead on a network.

Host-based IDS characteristics – A host-based IDS analyzes activities on the host it monitors at a high level of detail. It can often determine which processes and/or users are involved in suspicious activities.

Application-based IDS characteristics – An application-based IDS concentrates on events occurring within a specific application. They often detect attacks through the analysis of application log files and can usually identify many types of attack or suspicious activities.

In practice, most utilities use a combination of network, host and/or application-based IDS systems for observing network activity while also monitoring key hosts and applications more closely.

REDUNDANT CONTROL CENTERS

For both physical disaster recovery and IT intrusion and isolation purposes most utility companies are now adopting SCADA solutions that incorporate at least one off site control center. In some utility sectors this is now mandatory. This should be seriously considered as part of the overall security assessment of the IT infrastructure. For a redundant off-site center to operate effectively the following items need to be considered as part of the infrastructure requirements:

- Automatic failover of all controller-based communications;

- Full historical data replication between each of the servers deployed within the system.

ADDITIONAL RESOURCES

This discussion is intended as an overview of the security measures to protect an integrated SCADA network. In no way is it fully comprehensive or intended as the sole source for network security. Listed below are some agencies that publish current standards and security measures that can aid you in your security planning.

- The Instrumentation, Systems and Automation Society (ISA);
- National Institute of Standards and Technology (NIST);
- North American Electric Reliability Council (NERC);
- United States Department of Energy (DOE);
- U.S. Department of Homeland Security;
- Sandia National Laboratories – The Center for SCADA Security.

Scott Wooldridge holds degrees in electrical and mechanical engineering as well as an M.B.A. He has over 15 years experience providing production improvement engineering, IT, Project Management and Consultancy services to a variety of industrial, process, food and mining customers including: Rio Tinto, BHP Billiton, ALCOA, PG & E, Mitsubishi, Caterpillar and GM.

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to the following four statements:

A: There is no necessity to test because calculation methods are sufficiently adequate.

B: There is no necessity to test because service experience with transformers is so good.

C: The costs of testing have become prohibitively high and take too much time.

D: Short-circuit testing may have a deteriorating influence on the transformer under test.

The authors' opinion on these statements is the following:

A. "Calculations Can Prove Short-Circuit Withstand".

It is clear that calculation methods are an indispensable tool in the design phase of equipment.

Nevertheless, "the test procedure is considered a better means of ascertaining the real performance of equipment at short-circuit, since such a test demonstrates that both construction and design are adequate". Recently, this is recognized in an amendment to IEC 60076-5 Annex B that states for transformers > 2.5 MVA) that "for the purpose of evaluation the unit under consideration may be simultaneously compared with a limited number of transformers that have passed the short-circuit test successfully and match most - but not all - the characteristics considered in Annex A".

Currently, complex, three-dimensional time varying fields and forces stressing various non-homogeneous and non-linear structures and materials cannot be covered adequately by calculation. In addition, natural variations in properties of material, quality assurance, workmen's skills etc., especially in the less experienced companies, cannot be taken into account fully, nor can any design review reveal deficiencies resulting from this.

Complicated 'secondary' physical phenomena like shock waves in oil, shocks and vibrations (often leading to untimely falling-off of Buchholz relays or damage to ancillary equipment - bushings, tap-changers etc.) are normally not considered at all in calculation methods.

The use of calculation methods, however, can be and have been used efficiently by manufacturers to identify critical conditions for testing.

It is KEMA's experience that in spite of the very sophisticated modeling tools deviations up to 5% are regularly found between the designed (rated) and measured value of short-circuit impedance. This quantity has an intimate relationship with magnetic flux and short-circuit current, two vital parameters to calculate forces and stresses.

The great step forward that calculation methods have made in last decades, together with the increased emphasis on cost reduction, can lead to a practice of designing close to the margin, whereas in the past – due to a greater uncertainty and less cost pressure – a larger safety margin was built in, indicating that advanced design methods not automatically guarantee a more robust product.

B. "Few Transformers Fail in Service Due to Short Circuits".

A large scale international survey on

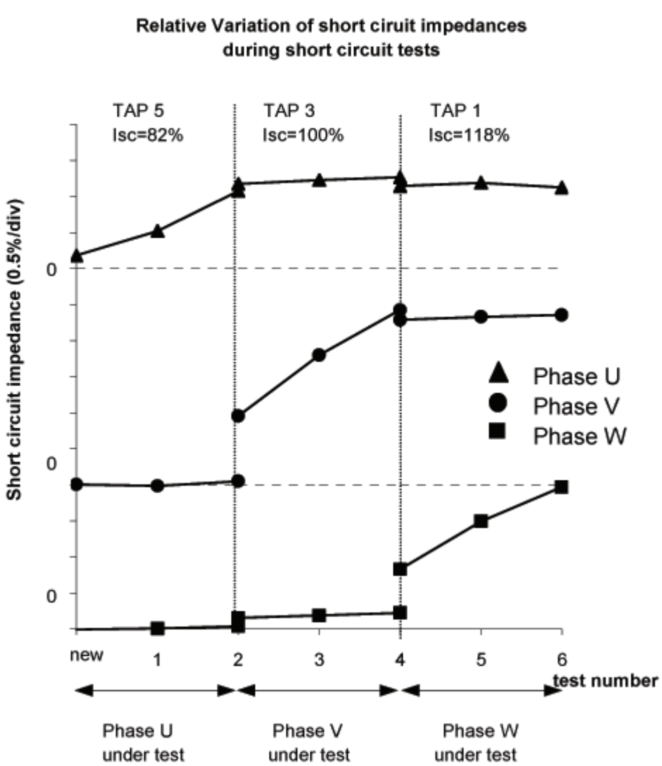

Fig. 2a. Transformer with common failure in all phases

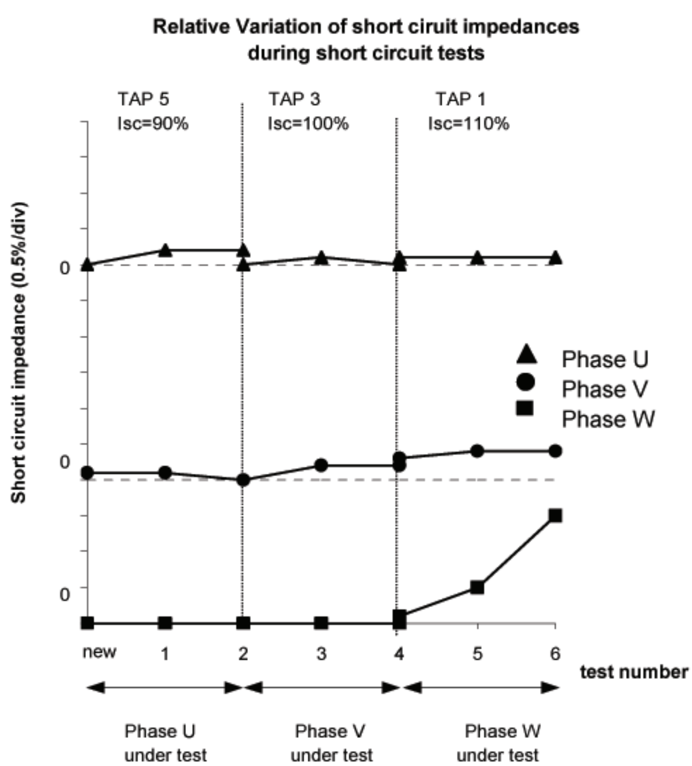

Fig. 2b. Transformer with a failure in phase W only

failures in service was conducted in 1983 by CIGRE WG 12.05. At that time, a failure rate of 2% was reported for HV transformers, and problems with manufacture were quoted as the largest known cause of outage, problems with the design being stated as the second largest known cause. Of course, this experience cannot be extrapolated to the present situation, nor can the correlation of it with short circuits be made.

Recently, new material was presented by CIGRE WG12.19 on the failure rate due to poor short-circuit withstand capability. A failure rate of 1.2 failures per 10,000 transformer years due to external short circuits is reported. It is striking that from the failed transformers, a third had passed a design review successfully, whereas none of the failed transformers had been submitted to a short-circuit test.

Unless it is assumed that short-circuit test requirements and assessment criteria as laid down in IEC 60076-5 are far beyond the practical situation, it must be concluded that test-results show the necessity to prove the manufacturers design and production methods by means of real tests.

C. "Short-Circuit Testing is Too Expensive and Too Much Time Consuming".

It is certainly true that considerable costs are involved in short-circuit testing of large transformers. These expenses however must be weighted against the importance of the function of the transformer in the network and the time it takes for repair or replacement.

The costs for testing are mainly made up of transportation, assembly, processing, repetition of dielectric tests, inspection etc., rather than the cost of the test itself. In addition, the largest cost factor, the risk of having to repeat the test after failure, is in direct control of the manufacturer. These costs must be evaluated against the risk of loosing transformers in service.

Although guidelines are difficult to give, some general considerations in such an evaluation are:

1. the importance of the transformer in the network in a 'reliability centered verification' approach (GSU units, auxiliary power in power plants, in feeder of critical customer etc.);

2. in cases where system operator's guarantee (against huge contractual penalties) access to power suppliers;

3. the local circumstances such as short-circuit level of the network, the incidence of short-circuits (severe lightning action, railway applications) and the short-circuit power of the transformer;

4. when several units at a time of a new design are going to be purchased, it may be advisable to make an investment in testing, increased reliability being the indirect pay-off;

5. some designs of transformers are more vulnerable to short-circuit current than others, e.g.: axial splitwinding type transformers are known to be exposed to severe stresses at high-current;

6. choosing test-methods (fast protection and fast fault current breaking,

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adequate grounding strategies etc.) with as much as possible efforts to prevent damage to the test-object.

Various large power companies have adopted the policy of requiring a short-circuit withstand test for each prototype of transformer purchased within the established procedures.

EDF (France) explicitly reports a significant and positive influence of short-circuit testing on the reduction of the rate of winding faults in the overall French experience of many decades. Similar experience is also reported from India. Others (among which NTPC-India, EGAT-Thailand, TNB-Malaysia) incite suppliers to pass a learning path towards a successful design through full-power short-circuit testing thereby using it as an essential and successful tool for quality improvement.

In China, all enterprises producing transformers recognize the value of short-circuit testing in quality assurance. The vast majority of users of transformers share this opinion. Transformer failure rate due to lack of short-circuit withstand capability show a drastic bending down of an upward trend after short-circuit testing was introduced in China in the mid-nineties. This is illustrated in fig. 1.

D. "Short-Circuit Tests Reduce the Transformer's Lifetime".

Reputable manufacturers agree on the fact that a properly designed transformer with enough margin to handle the electrodynamic stresses, the effect of the short-circuit stress will be that the windings undergo a certain settling. The effect of the settling is that the stiffness of the windings increases and this is visible in a small variation (if any) in the reactance values measured between the first tests, but becoming smaller or nihil at the last tests. Such a transformer is even stronger after the short-circuit-tests than before, and can be put safely in operation again. In the case that a continuous increase of winding reactance is observed during all tests, it is reasonable to assume (by extrapolation) that the transformer undergoes accelerated ageing due to the short-circuit tests.

In fig. 2, such an example is given. Herein, the change in reactance after successive short-circuit tests is plotted. The left graph (fig. 2a) indicates a common failure in all three phases (after visual inspection this turns out to be deformation of the helical windings), whereas the right graph (fig. 2b) suggests a failure of the W phase only (which turned out to be a defect of the axial clamping system). The other phases (U, V) will not deteriorate due to high current stress.

Chinese experience shows that 40 transformers (110 - 220 kV) put into service after passing short-circuit tests, function without problem during the monitoring period from a few months to more than 5 years.

Reputable manufacturers agree on the fact that a properly designed transformer with enough margin to handle the electrodynamic stresses, the effect of the short-circuit stress will be that the windings undergo a certain settling.

5. TEST PRACTICES

Two methods of applying the short circuit are defined in the standards: the pre-set and the post-set short-circuit method:

a. Post-set short-circuit (fig. 3 below). With the post-set method the transformer is energized at one side (the other side is open) and after the inrush currents have disappeared the short circuit is switched in at the other side. Before short circuiting, the source voltage Us appears at the terminals of the

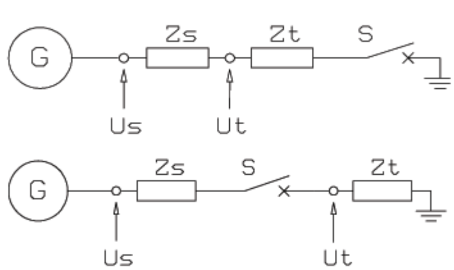

Fig 3: post-set (upper) and pre-set testing

transformer, so that the source voltage has to be limited in relation to the transformer voltage Ut. In the IEEE Standards a maximum source voltage of 110% related to the rated tap voltage of the transformer under test is allowed and in the IEC standards 115%.

Because of the very large power needed, this method can in practice only be used by test stations that are fed directly from the power grid.

The advantages of post-set testing are:

- representative of the real network situation
- accurate control of peak value of asymmetrical current is easier than in the pre-set situation (see below), especially if the transformer under test is fed through a short-circuit transformer and the make switch is placed upstream.

b. Pre-set short circuit (fig. 3 lower). With the pre-set method one side of the transformer is short circuited before the application of the voltage.

The source voltage Us may differ to a large extent from the transformer voltage Ut, as long as the required short-circuit current flows. With the pre-set method the short-circuit current is superimposed on the inrush current, but, thanks to the short-circuited LV windings between the core and the energized winding, the inrush current is not comparable with a normal inrush current or the inrush current of the post-set method.

In order to minimize inrush current, KEMA's testing procedure contains 80% premagnetization tests (with reverse polarity with respect to the 100% tests) between the 100% tests, to force the remnant flux in a certain direction. The full test is thus made in a polarity having a large margin until saturation occurs in that polarity. Because of a more efficient use of the source power in this method, generator fed test stations, such as KEMA prefer the preset method.

Single phase testing methods. Three-phase transformers should preferably be tested three-phase.

In case the voltage range is not sufficient or the short-circuit power is not enough, the testing authorities may use single-phase testing instead of three-phase testing. Like with three-phase testing, at each test one phase is subjected to the specified (peak) current value. During later tests the other phases are subjected to the required current.

A much more realistic approach is the 1.5 phase method, that (unlike pure single phase methods), takes into account the dynamic interaction between the phase windings. With the 1.5 phase method, the phase under test is connected in series with the other two phases, which are connected in parallel.

The currents in the two parallel connected phases are 50% of the specified three-phase value. At the moment of the peak in the phase, tested with 100% current, the current in the other two phases has equal value (1.28 pu) and polarity as would be in a three-phase test. Only half the power (single-phase power) is required from the test station compared to three-phase testing.

6. KEMA'S EXPERIENCE 1996 - 2004

Having available 8400 MVA of direct generator-fed short-circuit power (world's largest), KEMA can test transformers up the highest MVA and kV ratings.

Thanks to the generators, there is a good match of supply voltage with test-object, as well as sufficient time constant, and availability of power supply, which is not always the case in test stations that are supplied by the grid.

An evaluation is made of short-circuit tests in the 9 year period 1996-2004. The tests are performed in accordance with IEC standard or IEEE standards on transformers with power 25 - 440 MVA and voltage 33 - 500 kV.

The population includes single-phase and three-phase transformers, auto-transformers, step-up -, railway -, auxiliary - and three-winding transformers, 16 2/3, 50 and 60 Hz transformers, YD- and DY-transformers.

The largest transformers tested are 250 MVA single phase and 440 MVA three-phase.

During the past 9 years, in total 69 times a test access for a transformer larger than 25 MVA (62 transformers from which 7 are re-tested) has been counted:

• 22 transformers fully passed the requirements laid down in the standards, without any remark;

• 18 transformers have been tested without a problem due to short-circuit tests that became apparent at the test site, but a certificate has not been granted nor denied because KEMA was not involved in the subsequent routine tests, the inspection and the identification. These transformers initially pass the short-circuit test;

• 7 transformers faced a problem, but have been retested and passed the short-circuit tests after a modification;

Commonly, the reason of not passing short-circuit tests is because the winding reactance variation is larger than specified in the standards.

• 15 transformers faced a problem and have not (yet) been re-tested at KEMA.

From these results, an initial failure rate is defined as the ratio of test objects that resulted in failure to pass the test at first access (19 transformers) and the total number of transformers (62). Thus, the initial failure rate is 30%.

This is in the same order as the experience reported by another major test laboratory that reports a failure rate of 20-25% out 20 units > 100 MVA. Other sources state an overall failure rate of 23% for a total of 3934 tests.

In fig 4 and 5 results can be shown, differentiated in both power- and voltage class, not clearly showing a tendency of initial failure dependency on power or voltage over the entire period.

Commonly, the reason of not passing short-circuit tests is because the winding reactance variation is larger than specified in the standards. This is usually confirmed by visual inspection that revealed a huge variety of defects such as:

Axial clamping system: Looseness of force axial clamping, of axial compression force, of axial supporting spacers and of top and bottom insulating blocks;

Windings: Axial shift of windings, buckling, spiraling of windings (helical or layer winding);

Cable leads: Mechanical movement, for instance from tapchanger to regulating windings; deformed or broken leads, outward displacement and deformation of exit leads from inner windings; broken exit leads;

Insulation: Crushed and damaged conductor insulation; displacement of vertical oil-duct spacers; dielectric flashover across HV-winding or to the tank; displacement of pressboard insulation; tank current due to damaged conductor insulation

Bushings: Broken or cracked LV-

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bushings.

On the other hand, in the cases (the vast majority) that the reactance change is within the tolerances set by the standards, it is KEMA's observation that (visual) inspection only rarely (approx. 5% of the cases) still leads to rejection of a certificate.

Nevertheless, visual inspection is necessary, because deformations and displacements in supporting structures, clamping systems, insulation materials, winding exit leads, external connections from the coils to the tapchanger and within the on-load tapchanger can not be detected by the reactance measurements only.

Thus, the authors conclude that the reactance variation is a very good tool to assess short-circuit withstand capability right after the short-circuit test.

KEMA's experience with the short-circuit reactance measurements is that for power transformers a variation of more than 1.0% indicates a large deformation in one or more coils. Also a gradually increasing variation during the short-circuit tests, although in total not more than 0.5% to 1.0%, indicates a progressive movement of winding conductors. Variations of the reactance values between the short-circuit tests in a strange way form an indication of large flexibility of the windings.

A special item to be mentioned is the behaviour of Buchholtz-relays, as quite often (in KEMA's experience more than 50% of the cases) Buchholtz-relays operate unnecessary due to the vibrations that occur during short-circuit conditions.. Therefore, the behaviour of such relays is carefully monitored during testing and the observations are reported.

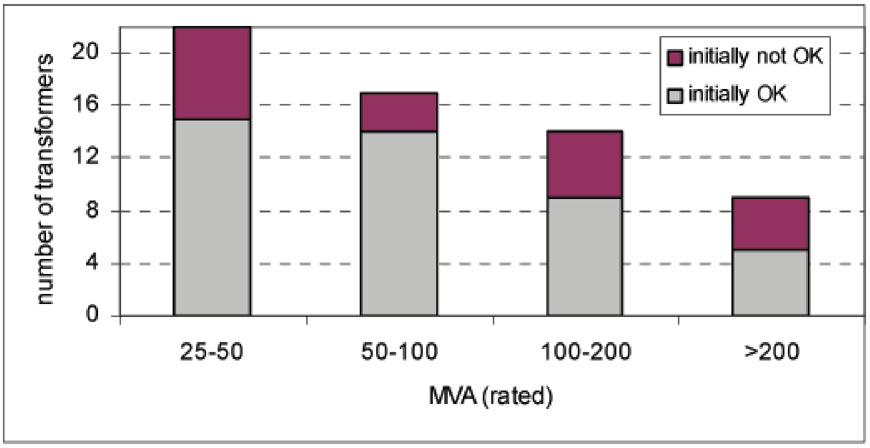

Fig. 4: Initial failure rate 1996-2004 in power class

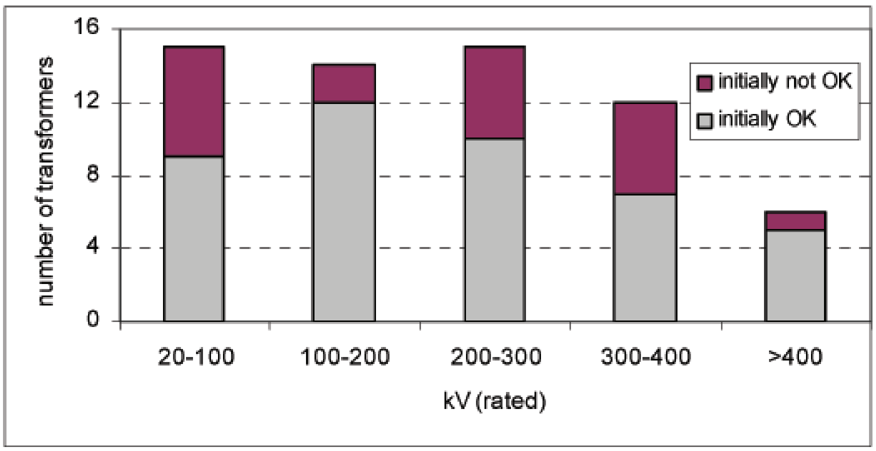

Fig 5: Initial failure rate 1996-2004 in voltage class

7. DISCUSSION OF TEST-RESULTS

One could wonder on what causes the high failure rate, observed by short-circuit test laboratories world wide compared to the much lower failure in service (see sect. 4). The main reason must be the severity of the tests, compared to actual service conditions. From a recent enquiry of CIGRE WG13.08 it can be concluded that on a statistical basis, large power transformers have to face several full and many small short-circuits during their life, more precisely: the 90 percentile was estimated to be 4 full short-circuits in 25 years.

Thus, it must be assumed that this actual (full) short-circuit current in service is normally (much) smaller than the rated short-circuit current for which the transformer is designed.

Because of the expected future increase in short-circuit power, especially in developing countries, this situation may change, and the fact must be faced that during the life of the ageing transformer, its withstand against short circuits will be brought to the limits.

The same discrepancy (orders of magnitude higher failure rate in testing than in service) exists with circuit breakers and distribution transformers, where type testing and certification under rated conditions of maximum required performance are undisputed and considered very valuable (not the least because of the marketing value of certificates), even when seemingly excessive conditions seldomly occur in practice.

Nevertheless, one should be critical towards the severity of test requirements. One example is the full short-circuit test in the highest tap positions, which is the case when short-circuit impedance is lowest at the highest tap position (see the example in fig. 2). Neither at maximum nor at minimum tap position, it is then likely to have maximum system short-circuit power available at the transformer's location. At the tap position, corresponding with the highest voltage, a very high value of short-circuit current is required in testing. This might have been the reason for failure of the W-phase in fig. 2b (110% current!). The very severe stress resulting from this may be extremely rare in service, since elevated system voltages do not occur simultaneously with maximum short-circuit power. Possibly, testing the extreme tap position with a reduced voltage is a more realistic requirement.

8. SUMMARY AND CONCLUSIONS

• The author's present failure rates of large power transformers subjeted to IEC60076-5 short-circuit tests:

KEMA shows that in 9 years of testing (of 62) transformers (25 - 440 MVA, 33 - 500 kV), 30% fails initially to pass the short-circuit test, mostly because an unacceptable increase in reactance. The change in winding reactance is a very good indicator for damage due to short-circuit current stress.

• Visual inspection confirms the results of the reactance measurements in the vast majority of the cases. However, in approximately 5% of unacceptable damage, that is not detected by impedance change, is revealed upon inspection.

• Short-circuit testing is a vital part of the design process, and the crucial verification tool at the end of it. The high failure rate at testing is the best demonstrations that calculation tools alone are not sufficient to design a transformer capable to withstand the worst case (rated condition!) of short-circuit current.

• Design review can not be the only part of an acceptance process: of all the transformers failed in service, one third passed a design review (without verification by testing) whereas none of the failed objects had been short-circuit tested.

• The author's experience with transformers that initially failed, but passed after modification demonstrates that the path to a successful and reliable product is a combination of calculation methods and verification by testing.

• The discrepancy between failure rate at testing (tens of %) and failure rate in service (in developed countries 0.5% per transformer assuming 40 service years) is striking. The explanation may be in the gap between stresses at rated conditions (at testing) and stresses in service (often much less than rated). This gap will narrow in the future.

• Many transformers in service are not able to withstand the maximum short-circuits for which they are designed.

• Short-circuit tests do not reduce the lifetime of well-designed transformers, on the contrary, a positive conditioning effect is expected.

• In most situations, the costs of outage, loss and repair / replacement of a transformer are far larger than short-circuit testing.

Nevertheless, one should be critical towards the severity of test requirements. One example is the full short-circuit test in the highest tap positions, which is the case when short-circuit impedance is lowest at the highest tap position (see the example in fig. 2).

DETECTING DISTRIBUTION TRANSFORMER FAULTS AND INCREASING DISTRIBUTION SYSTEM PRODUCTIVITY – PART I

By Wayne Clark, P. Eng., Senior Energy Industry Consultant, IFD Corporation

Utilities are constantly looking for ways to increase productivity in the distribution system. This means reducing the total lifecycle cost of the system; improving labor costs, improving customer service and protecting assets. This includes the value of improved worker safety. One area showing considerable promise of increasing the productivity is rapid detection of internal faults in pole top transformers.

Utility line crews re-energize single phase, pole-top transformers frequently. Over time, vendors improved the quality of transformers, fuses and related tools and equipment, making it more challenging for the line worker to detect equipment failures. Additionally, the need for faster problem resolution with fewer resources is a constant management challenge. This article outlines these challenges and describes a simple, direct, cost effective solution for utilities.

Pole top transformers are usually connected to the primary supply network via a fuse cutout. The fuse cutout is a protective device with two purposes. Firstly, by separating a downstream problem from the upstream supply, it limits the number of customers affected by the fault or overload. Second, by interrupting the flow of power to the fault, the risk of damage to equipment and injury to people is limited. The protective characteristics of the link are intended to serve both these purposes with a high degree of reliability, while also minimizing the frequency of unnecessary (nuisance) operations.

The reason for excessive current includes internal faults caused by failure of the transformer insulation system. However, unless the internal fault produces signs on the transformer's exterior, it may be difficult to reliably detect and confirm its presence without cumbersome and time-consuming measures. For example, it takes at least 15 minutes to disconnect the secondary leads to enable the line crew to measure the impedance of the transformer and/or check the integrity of the insulation by applying a test voltage from a suitable source. Therefore, the challenge to utilities is how they can efficiently and reliably determine if an internal fault has occurred.

TRANSFORMER FACTS

Service personnel often need to locate, diagnose and correct the causes of outages rapidly. The work is usually outside normal working hours, often in less than ideal working conditions and with a high workload relative to the number of skilled people available.

Consider these facts:

• There are over 50,000,000 distribution transformers in service in the USA and Canada.

• On average between 3% and 5% of the in-service population of pole top transformers are re-energized annually, which is between 1,500,000 and 2,500,000 transformers per year.

• Transformer fuse operations are the most common equipment failure on distribution systems, comprising as much as 40% in one study.

• Distribution transformer failures follow a 'bathtub curve'. That is, the highest failure rates are in the first few years of service and then decline. Failures increase later, towards the normal end of service life. In between, severe overloading or lightning causes most transformer failures.

• In most jurisdictions, lightning is one of the most commonly cited causes for outages and transformer failure. Twenty-five percent is a typical number.

• In an Ontario study, it was noted that, while storms occur about 7% of the time, they account for 30% of all outages. Moreover, lightning is the most commonly cited cause of equipment failure during storms.

• Most lightning occurs during the evening and night – after hours, which because of the weather and limited visibility, often causes crews pressure.

Service personnel often need to locate, diagnose and correct the causes of outages rapidly.

• The Canadian Electricity Association (CEA) analyzed how pole top transformer tanks actually fail in service. Of a population of over 400,000 units, there were approximately 20,000 fuse operations per year. This information was obtained by monitoring the Ontario Hydro (now Hydro One) system over a three-year period. In the 20,000 fuse operations, a total of 4,000 units failed per year. One in 270 fuse operations were explosive in nature. This rate of explosive failure is consistent with two previous unpublished studies, one by Ontario Hydro (1/300) and another by Nova Scotia Power (1/250).

• These studies indicate that, on average, explosive transformer failures occur a few times every day in North America.

FUSING OPERATIONS

The fuse cutout is designed to protect the transformer and related equipment and services. About 20% of the time, when the cutout operates, the transformer has failed. The rest of the time, the cutout has operated for a non-transformer problem. However, unless the reason for the failure is obvious, the line worker has a time consuming problem determination process to follow. A tool that can readily identify when a component has failed saves time in all circumstances.

If a transformer has obviously failed, the investigation can be stopped and the unit replaced and resources can be more quickly released to fix the next problem.

When the line worker knows the transformer is not faulted, which is in approximately 80% of the refusing operations, the line worker can look to different causes for the fuse operating before starting the process of safely re-energizing. This allows the line worker to focus on the more likely outage sources and leads to a faster, safer resolution to the problem. So, in all circumstances where the fuse has operated, the line worker saves time if there is a transformer failure identification tool.

TRANSFORMER FAILURES

The rate of transformer failures is often debated. Few utilities have good tracking systems, however, there are a few utilities such as Progress Energy and HydroOne who have maintained detailed records of transformer failures. This paper references these sources which are generally supported by engineering and operations staff. They are the best reference available for 'numbers'. Line workers typically state "we rarely report failures, re-energizing faulted units happens all the time".

This said, most transformer failures are uneventful. The combination of well-built transformers and fuses, the fault progression inside the transformer, plus limitations on the available fault current provides a degree of protection to the system. When failures are described as 'uneventful', it is important to understand this is a relative term. It means the failure did not result in an explosive release of oil. However, the various techniques for internal fault identification include re-fusing, and if the transformer is faulted, a fuse operation itself is a dramatic event for the line worker, just less so than a full transformer failure.

EVENTFUL TRANSFORMER FAILURES

Eventful transformer failures describe a tank failure where the tank is visibly damaged due to an internal fault. The damage may cause no significant impact, aside from the need to replace the tank, or it could be catastrophic. Distribution transformers always have the potential for eventful failure. As line voltages and fault currents have increased steadily over the years, and continue to rise, this potential is realized with increasing frequency. The fault energy available between inception of a fault and fuse clearing more frequently exceeds the withstand capability of transformer tanks and lids.

While current related failures are rising, lightning is still the leading cause of failures. High currents from lightning (or from other sources) can cause under-oil-arcing, either voltage surge through the arrestor or by moving the leads by means of the electromagnetic forces accompanying the surge.

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transformer faults

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In addition, the oil itself could release energy under fault conditions, when hydrogen is released as a breakdown product.

A number of researchers have identified the failure mechanisms. All involve an arcing fault in the tank, which creates a shock wave or pulse (piston) of oil. The arc may be just under the oil, above the core/coil assembly or deep down in the tank. The arc energy causes a pressure pulse with a fast rise time and a high peak pressure in the air above the tank. The lid attachment of the tank is the usual weak point but the welded seam may also rupture.

One question that naturally arises when investigating an eventful failure is, “What is the threshold below which violent failures will not occur?” Despite numerous studies, the answers are far from clear. Several test programs show correlations with fault energy (I2t), arc energy (joules or Watt-seconds), available asymmetrical fault current energy (I•t) and peak fault current. The results indicate that tank failure is unlikely at fault currents below 2,500 A symmetrical. This assumes all the mechanical components of the fusing system operate as designed and the transformer tank is free of structural defects.

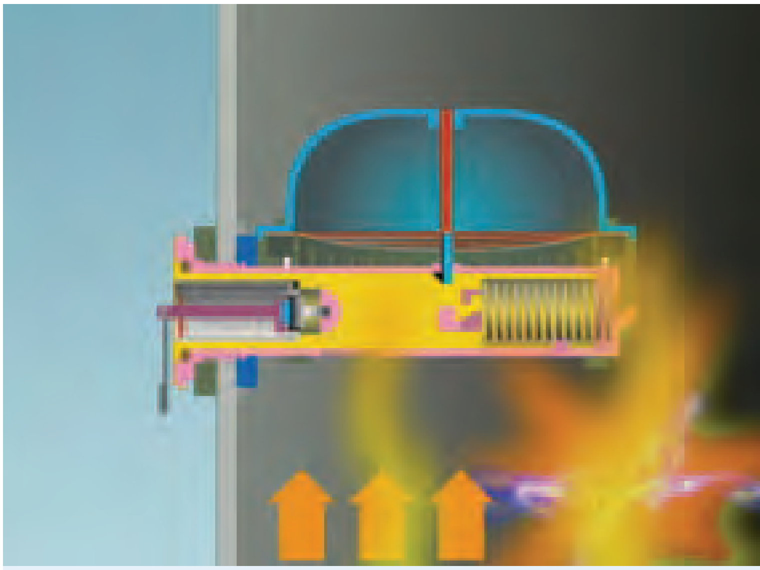

Figure 1
Prior to operation, the pressure detecting membrane and its trigger shaft (red and blue vertical rod) are in the lowered position, locking the indicator (yellow) in place. The large spring on the right side stores the energy to push the indicator out; the small coaxial assembly on the left is the pressure relief device (PRD).

FIELD EXPERIENCE

If the tank failed just before the fuse operated, the consequences to the transformer might be limited. However, faults often do not cause eventful failure before the first fuse operation. Eventful situations often occur when the line worker is reclosing on already faulted units. This can place line crews in a hazardous situation.

Internal transformer faults develop to the point that the cutout will operate, but there may be no visible external indication of a transformer fault other than the fuse operation. It is often unclear whether the transformer has failed or the fuse has blown for some other reason in spite of a thorough external examination.

In this situation, a line crew will normally re-fuse and close back in the line. While many utilities require crews to test the transformer, this is often not done if everything appears okay. This is understandable, since most fuse operations can be attributed to lightning surges, short duration overloads, improper fuse selection or installation and secondary faults.

Unfortunately, if the transformer has already developed an internal fault, this can set up the conditions for an eventful failure, and put the line crew in a perilous situation when re-fusing the transformer. Far from being a hypothetical situation, there have been a number of injuries and even fatalities from this situation over the years. Almost any line crew with a decade or more of experience can recount at least one close call in a similar situation.

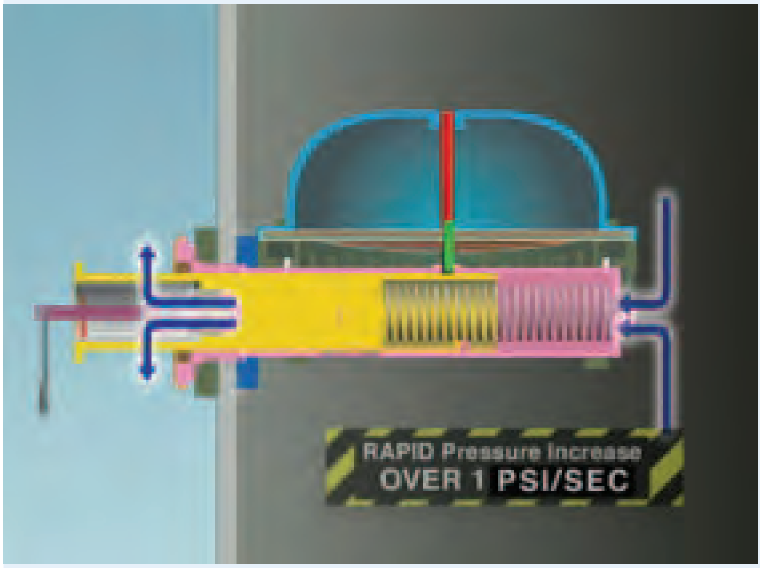

Figure 2
When the membrane reacts to pressure pulse caused by an internal fault, it moves up, carrying the trigger shaft with it (red and green). This releases the indicator, which is pushed out by the spring. Once this happens, pressure is relieved through the IFD. The blue arrows indicate the flow of gas through the indicator assembly.

Most utilities have written procedures intended to mitigate this risk. Some require isolating the transformer and doing a ratio check of the windings. This involves climbing the pole, disconnecting the transformer, testing the transformer and then reconnecting it – obviously a time consuming process. This is a sound approach, one that should be encouraged. However, it is frequently not done due to pressure placed on the line crew to restore power, especially when weather conditions result in large numbers of service interruptions or other time pressures are imposed on the crew.

Some utilities may rely on a visual check of the transformer, combined with specific precautions by the workers to minimize their physical exposure should a violent event occur. Some linemen will pull the ring on the pressure relief device to see if the telltale odor of electrical burning can be detected (Note: this does not work well in cold weather if the transformer has had time to cool down. Pulling the ring will only allow the pressure release device (PRD) to suck in cold air, with no odor escaping. It is also an unreliable technique if there has been limited carbonization of the oil.) Moreover, the act of letting cold moist air enter the tank is bad for the transformer. Moisture is the enemy of paper insulation and a large factor in transformer aging.

Lightning storms are perhaps the best example of how a number of related factors can converge to produce a large risk of a faulted transformer. In a severe lightning storm, literally thousands of fuses can operate in a limited geographic area in a period of only a few hours. This creates tremendous pressure on linemen working to restore power. The temptation to move quickly by simply re-fusing transformers and closing back in is significant. At the same time, lightning may have created faults that could lead to violent failure when the unit is re-energized. At times like this, the line crew needs all the help it can get.

BUILT-IN INTERNAL FAULT DETECTORS

Before the development of a specific internal fault indicator, all other approaches relied on indirect measures such as the logical approach of CSP transformer designs. (The one exception is off-line testing technology, which is somewhat complex and time consuming to use when the line worker is on the pole.) The industry needed an innovative way to identify internal faults 'directly' and flag the fault outside the tank so a line worker could easily see it.

When utilities began moving to higher distribution voltages and higher available fault currents in the 1970s, the increases in available fault energy resulted in most utilities experiencing an increasing frequency of eventful transformer failures. Several research projects were designed to gain an understanding of the physical phenomena underlying these events. The gas generation mechanism was quickly identified as the main culprit.

The first work on internal fault detection technology occurred in the late 1980s, when engineers were conducting transformer withstand tests. Testing showed internal faults produce unique pressure signals. All other pressure changes in a transformer's air space occur 1000 or more times slower than the rate of rise during the pressure surge created by internal arcing faults. So, the rate of pressure rise can be used to reliably identify the occurrence of an internal arcing fault.

THE IFD

One detection method measures the pressure differential across a flexible membrane to activate a fault signaling mechanism. One device that incorporates this principle is the Internal Fault Detector (IFD), developed by IFD Corporation. The IFD was in development for over a decade, and represents the result of a collaborative R&D effort involving financial and technical support by a group of utilities. The objectives of the IFD were to improve lineman productivity, enhance customer service and increase lineman safety associated with transformer failures.

The IFD only responds to internal transformer faults. The purely mechanical design provides inherent advantages over other sensing schemes. The sensor is a specialized membrane that is sensitive only to a rapid rise of pressure in the air above the oil. This rapid pressure rise occurs only during an internal fault. When the membrane moves in response to the rapid pressure rise, it releases a spring-loaded, readily visible indicator on the outside of the tank. It does not carry the sensitivity vs. selectivity design compromises inherent in thermal and electrical over current or waveform signature sensing devices.

The IFD requires no power supply, is insensitive to its electrical environment and does not depend on the electrical status of the transformer to operate. The IFD does not react to electrical or magnetic fields or even temperature changes (within the limits of the transformer design). It operates reliably in an environment that would destroy most electronic devices.

On a practical note, the simple mechanical design and construction of the IFD make it economic to manufacture and install in distribution transformers, where large volumes make unit cost an important selection factor for utilities.

The IFD also includes a static pressure relief device (PRD) that operates like a standard PRD. Customers asked that this function be included in the IFD so the solution would not require another hole (point of failure) in the tank. This also reduces the current total tank cost due to elimination of the welded tank boss required in most standard transformer designs. The IFD can easily be added to an existing transformer and only requires a punched hole to install. This makes it easy for utilities to retrofit IFDs into existing transformers, when they are returned to stores, or when they are refurbished or rebuilt. Figures 1 and 2 show a cross sectional drawing and

continue on page 40

transformer faults

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mode of operation.

The IFD cannot be reset from outside the transformer. This ensures the IFD on a faulted transformer is not reset and the transformer should not be re-energized without first removing and inspecting the transformer in the shop.

The IFD is also designed to minimize the chances that it will 'falsely operate' under conditions other than a fault, such as mechanical shocks. With distribution transformers, this type of condition sometimes occurs during transportation and, perhaps, installation. To avoid this problem, the IFD is equipped with a plastic shipping lock that is easily removed once the transformer is mounted on the pole. The shipping lock has a jagged shape and is bright orange, so if it is inadvertently left in place, a line crew can easily identify the lock from the ground.

TECHNOLOGY VALUE TO UTILITIES

Challenges for utilities to continuously improve cost/performance and service have never been greater. This is compounded by the fact that industry forces constantly shift and changes take a long time to implement. Distribution systems must integrate new and old technologies in an evolutionary, cost effective way. Strategically, utilities have to consider the value of technical solutions over the life of the system, where key forces include changing experiences and skill levels of line workers, a drive to reduce costs and improve service levels. Importantly, safety is high in the corporate mission and objective statements.

These considerations were all a key part of looking for low cost, simplicity and reliability in a transformer fault detection tool. The end goal is to assist in the journey of 'doing it right the first time.'

The IFD provides financial benefits to utilities in the following areas:

Productivity Improvements with IFD

- **Timesaving… over 20% of costs in 'Distribution Resource Commitment' are labor costs.**
- **Problem determination time is reduced. Many utilities estimate IFD cuts anywhere from 15 minutes to 30 minutes from the time needed to determine the problem.**
- **Efficient crew utilization… right people, right place, and right time; particularly during storms and other high visibility events.**
- **The average number of crews called out for any given storm situation can be minimized for a constant service level.**

RESTORATION COST SAVINGS THROUGH PRODUCTIVITY IMPROVEMENTS

Over 20% of costs in the distribution resource commitment are labor. Therefore, improvements in labor utilization will improve the bottom line.

The most obvious benefit of the IFD lies in the ability of line personnel to quickly spot transformers with internal faults.

This benefit will vary by utility, depending on their practices with respect to outage management. The following examples are illustrative:

SITUATION ANALYSIS TWO MAN CREW

In this example, a two-man crew, using a bucket equipped vehicle or material handling aerial device, investigate the outage. The crew may be dispatched from a local office or central operating center. The hourly rates for this combination are quite high, including two skilled trades' people, expensive work equipment and, often, overtime pay rates.

While this arrangement has impressive work capacity, most of the outages handled involve inspection, re-fusing and re-closing. If the utility adheres to a 'test before re-close' practice, the crew will spend a great deal of their time isolating, testing and reconnecting transformers with no internal faults.

Now consider the same operation, where transformers are equipped with IFDs. If the transformer has actually failed, the crew will in all probability, know immediately by looking at the IFD. If it has not operated, the crew proceeds with its normal practice, just to be sure. If the IFD has operated, they can order a new transformer without even getting out of the truck.

Descripton	COSTS
Truck and two crew (per hour)	\$100-750
Estimated fuse costs	\$5-25
Financial analysis when an IFD is installed on the faulted transformer	**SAVINGS**
Truck and two crew (1/2 hour savings)	\$50-375
Fuse savings (increase this by number of attempts)	\$5-25
Savings per transformer	**\$75-370**
Less IFD cost	\$35-\$45
Net Savings per transformer	**\$30-335**

In this case, (because the crew did not set the outriggers or raise the boom) it can quickly proceed to the next trouble call. The workers can either go back to the original location when the new transformer has arrived, or leave it for the crew that brings out the replacement unit. If they are lucky, the line workers may have the correct spare on the truck.

Most utilities reviewing this scenario believed the IFD would save at least half an hour, on average. One standards engineer provided the following savings range estimate.

Descripton	Units
Transformers out of service	100
Transformers showing the IFD flag (faulted)	20
Problem determination time reduction (1/2 hour multiplied by 20 transformers)	10
Financial analysis when IFD are installed on the faulted transformers	**SAVINGS**
Labor cost savings (10 hours multiplied by \$200 to \$1,400 (overtime rate))	\$2,000–14,000
Fuse savings (20 units multiplied by \$5 - \$25) (assumes only 1 fuse attempt)	\$100-500
Savings overall per 100 transformers	**\$2,100 - \$14,500**
Savings per transformer	**\$21-145**

SITUATION ANALYSIS TWO MAN CREWS DURING A STORM

Cost savings increase if we use the same example above, but expand it to address a typical storm restoration. As mentioned earlier, about 30% of outages occur during storm situations. Further, most storms hit outside normal working hours. In these situations, most of the available crews will be involved in restoring power. If the utility can save a half hour of problem determination time per transformer when paying time and a half or double-time, the cost savings add up very quickly.

For illustration purposes, consider the following storm example:

These savings of time and money are related to more than this one crew. By making trouble crews more productive, utilities can delay (or avoid) calling in additional crews. Improving the efficiency of the first crew thus has a magnifying effect on overall savings.

SITUATION ANALYSIS CRITICAL EVENT

In this example, a two-man crew, using a bucket equipped truck investigates an outage. The transformer has an undetected internal fault, and there are no external signs of a failure. When the line worker closes the line back in, the transformer has a catastrophic failure. The line worker(s) is injured and can be expected to be off the job for an extended period of time. Other assets are damaged and repair is extensive.

Costs include: Time lost from work, time dedicated to accident investigation and reporting, uninsured medical costs covered by company, employee’s loss in earning power, economic loss to the injured person’s family, legal costs, occupational health and safety worker wages, supervisor time, management time, medical and compensation insurance, cost of training temporary or new employees, oil clean up, pole replacement, landscaping, potential penalties, potential fines and negative public relations.

It is difficult to consider this potentiality, and the topic is often avoided due to its infrequency and the nature of the subject. Nonetheless, the costs for this type of incident are always extensive and range from hundreds of thousands of dollars to millions.

RETURN ON INVESTMENT CONSIDERATIONS

The rate at which operational benefits can be realized will vary from utility to utility. However, all of the elements include improved operations, better customer service, an improved safety environment and better environmental protection.

Over the past number of years, the population of linemen has reduced to about 110,000, half by some measure of what it was 20 years ago. Utilities have restructured and outsourced. This means utilities have to increase the efficiency of the line crews. Additional savings will be harder to come by and will require utilities (at least those that have not already done so) to modify their operating structure and practices. The trend to improved productivity will continue and better tools are key to achieving the business objectives.

Two complementary strategies are at work to create continued productivity improvements, particularly in outage management.

The first (and in some ways the easiest step to implement) is to increase the amount of information available to the utility to manage outages. This includes weather information, crew locations, lists of available material and data sent in from utility systems. This provides for efficient central dispatch of the right quantity and type of resources. Going under the catch-all title of ‘distribution automation’, systems providing this type of data include SCADA, GIS, DMS and outage management. Every utility implementing these systems seems to have its own unique mix of capabilities, but the general trend for outage management is the same.

The second strategy takes advantage of the opportunities provided by these systems. With centralized information collection comes centralized dispatch. For large utilities, this effectively removes the role of the local dispatch center. The result can be significant reductions in dispatch operations, facilities and overhead costs, but also fewer and more widely dispersed operations centers.

This step also results in an increase in average travel time. Effectively, the availability of skilled trade resources is reduced and the unit cost of the workforce (wrench time) increases. Today, the real, total burdened cost of wrench time for a two-man crew with a bucket truck can be in the hundreds of dollars per hour.

Aside from the need for the utility to focus resources more carefully, a new risk is also introduced. With fewer available resources, the utility is at a greater risk when large storms hit. Against this background, the IFD can be seen as a key information source, providing enhanced and quick trouble shooting diagnosis.

For those utilities looking toward a future of greater automation and even higher focus on productivity and cost, the IFD is a valuable part of the solution. Seen another way, the IFD provides utilities with one of the most common information requirements in outage management.

Look for Part II in the next issue of Electricity Today magazine

NEW ROLE FOR T&D INFRARED: 24-7 MAINTENANCE/SECURITY SUBSTATION MONITORING

By Jon Chynoweth,
VP Mikron Infrared

Infrared thermography is the stuff of legends in the utility industry. Everyone's heard war stories about serious equipment faults averted by early detection with infrared. It's not uncommon for an IR camera to pay for itself in a matter of days, if not the first use. Making those cameras smaller and more affordable has been the goal of the industry, and a new generation of cameras introduced in late 2005 sets a higher-than-ever standard for performance and low cost.

While IR is a proven predictive maintenance tool, most utilities still use it only for periodic inspection of substations. A 30-90 day cycle is common. However, a number of forces at work in the industry are changing the role of the IR camera:

1. Loads on aging equipment are as high as ever. Problems are more likely to go from minor to critical in a short time, so 30-90 days between checks may be inadequate.

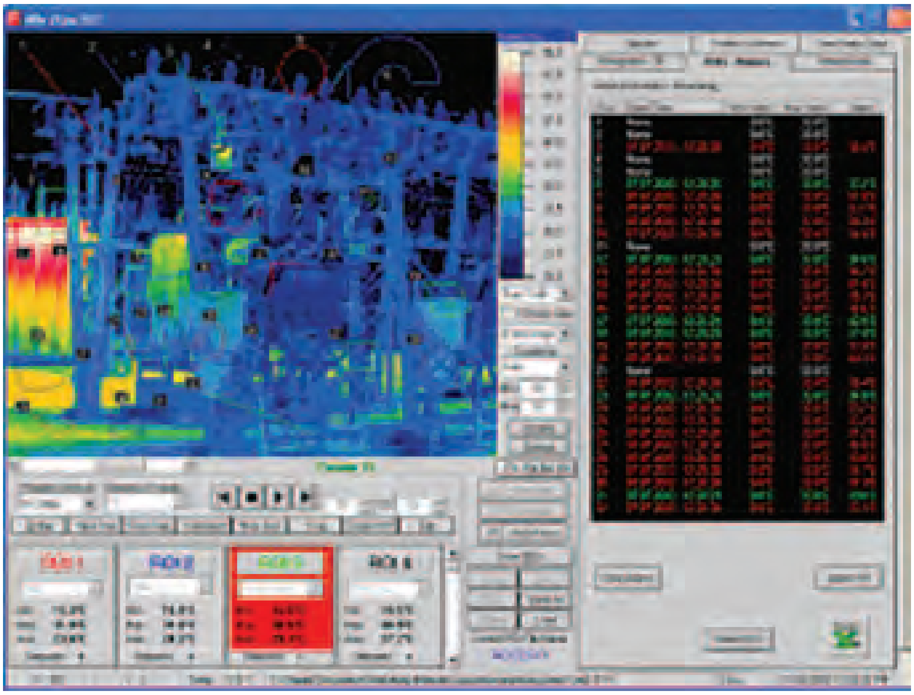
2. Homeland security implies higher physical security for the grid.

3. Replacement costs and lead times for utility equipment are high. A better understanding of equipment health allows more precise timing of expenditures.

4. Leaner organizations must improve utilization of trained thermographers.

5. Improved development tools, such as Visual Studio, have allowed creation of applications for real-time analysis and communication of IR camera output.

As a result, an imperative has developed for round-the-clock remote monitoring of substations with IR cameras, just as it is becoming feasible and cost-effective to do so. Remote thermal imaging is coming of age in time to answer the utility industry's combined needs for increased substation security against terrorist attack, as well as comprehensive maintenance monitoring for aging hardware installations.



Real-Time Thermal Data Acquisition and Analysis software is the heart of the system. It allows 32 regions of interest (ROIs) to be defined on the thermal image, in any complex shape. The emissivity of each ROI can be set separately, and each ROI can have its own high/low alarm setpoints. The software can affect a control output, put an alarm on the screen or send an alarm to a SCADA system.

The newest generation of these systems combines visual and IR cameras with airborne ultrasound detection. The infrared and visual images can be blended and transmitted to a PC via wireless intranet/internet, enabling clearer, faster identification and pinpointing of both physical incursions and thermal anomalies at remote sites. Ultrasound detection adds another sensor capability to the system, picking up arcing, tracking and corona that might not be detected with the IR camera.

This type of system is currently being integrated with a proven substation data collection system that includes load monitoring. The visual/thermal patterns

The DualVision Ultra 724 camera setup consists of separate thermal imaging and video cameras, plus ultrasound sensor, housed in a single environmentally sealed, temperature-controlled enclosure. The front section holds the cameras and has a slanted IR-transparent window to resist snow/dirt buildup.

correlated with actual operating loads on the hardware provide a new tool for better understanding what constitutes a normal and safe state of the equipment.

This system can also perform presence sensing and intruder detection, while monitoring transformers, regulators, bushings, etc., for temperature excursions. New software allows one IR camera to monitor 32 user-defined regions of interest in the thermal image, each with its own alarm setpoints. Thus, each camera can simultaneously monitor 32 areas of interest on substation hardware, fence lines, gates, access roads, etc.

The software produces a composite IR/visual image, as well as separate images of each. The resulting composite can be viewed in an infinitely blended percentage of visual/IR, simply by moving a slider bar in the software screen. The visual surveillance capability of the system, enhanced with IR imaging, makes it easy to spot intruders 24/7, without supplementary lighting.

Through a secure Internet connection supervisors can view conditions and alarms at a substation. Long-term trend data is easily developed to allow better-informed decisions on crew dispatching, work priorities, maintenance cycles and timing of equipment replacement, ensuring best utilization of capital and manpower.

SOFTWARE ENABLES ONE CAMERA TO DO THE WORK OF 32

The Thermal Data Acquisition and Analysis software is the heart of the system. It allows 32 regions of interest (ROIs) to be defined on the IR camera's thermal image, in any complex shape. In short, the user defines an area of the IR image, and the system constantly monitors its temperature. The emissivity (key to accurate radiometric imaging) of each ROI can be set separately, and each ROI can have its own high/low alarm setpoints. The software can affect a control output, put an alarm on the screen or send an alarm to a SCADA system.

Ten different shapes are available to define the ROIs, including freehand. And, all 32 ROIs are monitored simultaneously by the software, with multiple camera systems being supported by one software installation. An operator can view the output from any one of the systems with the click of a mouse, and the software will automatically jump to any camera with an alarm condition. In addition, the software displays the temperature for any point of interest when the cursor is swept over the image, or it can be directed to do a "peak search", where the cursor will go to the hottest spot in the image.

The software blends the visual and IR camera feeds into a single image with correct aspect ratio and spatial area. By applying an isotherm color pallet to the IR image, hot spots are easily identified while still viewing the scene as a visual image. To the operator, it appears as if a temperature reading is being taken on a visual image.

Temperature values from the ROIs can be output to utility process systems using single-point I/O modules, so a specific ROI channel can have a min/max or average temperature setting, and the 4-2 mA outputs are mapped to this. Thus, each channel is programmable to what the user wants 4 and 20 to equal, and the range in between is fully linearized.

For utilities running PLCs or ACS systems, the camera can be configured to interface with a PLC, rather than I/O modules. The technology is not restricted to using a field point system to interface the software with the plant.

Currently, the software can record up to 75 minutes of blended visual and IR video to a hard drive when capturing every frame from a camera set at a frame rate of 30 Hz. Total

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EDUCATION AND NETWORKING FEATURED AT METERING AMERICA

Education and networking opportunities for electric, water and gas utilities abound at the 7th annual Metering, Billing/CIS America conference, scheduled to take place in Atlanta, Georgia, April 23–27.

The event falls under the American Utility Week banner and will bring together an expected 1,000 key decision-makers from the North American utility industry for seven days of activities, including: workshops, conferences, training, lectures, networking, field visits and a trade show.

Speaker highlights

Keynote speaker at Knowledge2006: **24 April**

Jean-Michel Arès, Vice President and CIO, The Coca-Cola Company

Keynote speaker: **25 April**

Mickey A Brown, Executive Vice President: Customer Service Operations, Georgia Power Company

Exhibition opening times:

Monday 24 April: Open to invited guests for demos and press only: 12– 5 pm

Tuesday 25 April: Open to all attendees: 10 am – 7 pm

Wednesday 26 April: Open to all attendees: 10 am – 2 pm

This unique platform will provide strategic insights on the technologies and trends shaping the future electric, water and gas utilities enterprise, beyond the ‘hype-cycle’.

Through the integration of four leading events - Metering America, Billing/CIS America, Knowledge2006 and UtilityPlus - as well as partner events, American Utility Week will offer the premier platform for the industry to explore the future, offering real solutions and opportunities.

NEW INFRARED CAMERA DETECTS VOLATILE ORGANIC COMPOUNDS THAT POSE HEALTH, ENVIRONMENTAL DANGERS

Often referred to as “fugitive gas emissions”, Volatile Organic Compound (VOC) gases are a major contributor to global warming, cost industry billions of dollars in regulatory fines and damages, and pose deadly risks to both workers and people living close to these facilities. These gases are also a major contributor to higher gas prices.

A new technology, GasFindIR, inverts the physics of fugitive gas leaks. What was once an invisible peril is now clearly revealed.

“It’s good to see the results of our long-term investments and strategies pay off,” said Earl Lewis, president and chief executive officer of FLIR Systems, Inc. “We’ve integrated core competencies across the board, using our knowledge and experience in making military-grade, battlefield-ready IR cameras and adapting them to the exceedingly harsh conditions of petrochemical facilities, a battlefield of a different sort.”

GasFindIR is the first commercially viable infrared camera capable of detecting VOC gas emissions from petrochemical facilities, gasoline refinery installations, natural gas pipelines, transfer stations, supertankers, moving railway tank cars and even landfills emitting methane gas and other toxic chemicals into the environment.

substation monitoring

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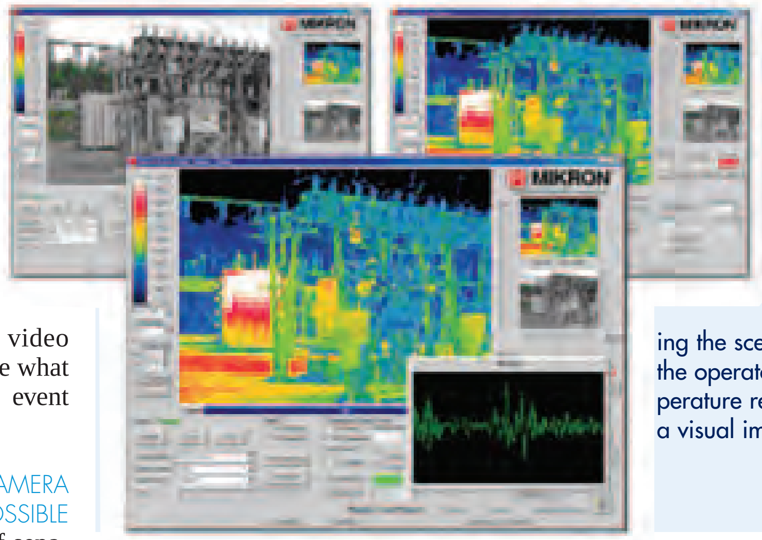
record time can be greatly extended by capturing images at intervals, rather than continuously. Video capture can be triggered by a temperature alarm from one of the ROIs or by direct input from the PC. A user-selectable prebuffer of video allows the operator to also capture what happened in a scene before an event trigger.



The software blends the thermal and IR camera feeds into a single DualVision image with correct aspect ratio and spatial area. By applying an isotherm color pallet to the IR image, hot spots are easily identified while still viewing the scene as a visual image. To the operator, it appears as if a temperature reading is being taken on a visual image.

INEXPENSIVE CAMERA TECHNOLOGY MAKES IT POSSIBLE

The camera setup consists of separate thermal imaging and video cameras housed in a single environmentally sealed, temperature-controlled enclosure. Ultrasound detection can be added to the housing as an option. The ultrasonic sensor and both cameras have Internet IP addresses and offer password protection, allowing control from any computer using wired or wireless Ethernet.

The visual camera can be color or b/w. Cameras can be fixed focus or have auto iris and remote focus. The standard IR camera uses state-of-the-art uncooled UFPA microbolometer technology, providing measurement accuracy of ±2% or 2°C. It can be set manually or automatically for three different temperature ranges. Two image update rates (30Hz/60Hz) are selectable. Standard field of view is 28.9°(H) x 21.9°(V), with autofocus from 30 cm to infinity. Telephoto and wide angle lenses are available.

The housing has a hinged back section containing all the interface connections, including RJ45 Ethernet, RS170 video, connection for a high-resolution LCD, and a power termination strip. The front section holds the cameras and has a slanted IR-transparent window to resist snow/dirt buildup. Cameras are supported on an internal shelf, with space underneath for power supplies, wiring, etc. A remote-controlled pan-and-tilt head is also available.

In addition to substations, this system is ideal for telecom/broadcast facilities, coal piles, hydrocarbon processing plants and similar facilities. Cost depends on configuration. The level of technology, too, should be integrated by a single-source provider on a turnkey basis to limit the variables involved.

In developing any remote monitoring system, keep in mind the need for secure communications. A SCADA system is a fantastic tool, but when remote communication devices are involved, it's important to know the vulnerabilities and address them with proper security technologies.

Jon Chynoweth has been involved in the development and marketing of thermal imaging cameras and related software for 20 years.

Donald Schubert

THE MAKING OF "THE LIFE OF A TRANSFORMER"

It was quite a production. They came by the hundreds from 25 countries as close as Canada and as far as Namibia, Africa. They came for all kinds of reasons: to understand the logistics of acquiring a new transformer, to probe issues like corrosive sulfur, or to "drill deep" into the intricacies of system design, standards, and specifications.

What more than 350 people who attended the Fourth Annual Doble Engineering "The Life of a Transformer" Seminar held recently at the Hilton Clearwater Beach Resort, had in common, however, was a single aim: to learn from the best, which is exactly what they did. They tapped into the unparalleled expertise of industry specialists – more than 30 presenters who focused on what they knew better than anyone, from high-level overviews of transformer design to analyses of bushings, surge arrestors, and load tap changers. For an even more enriching experience, delegates shared their own anecdotes with one another.

Overheard, for example, was the following comment: "When you have a transformer failure, it's like a crime scene. All that's missing is the white chalk outline."

If understanding transformer failures – and ways to prevent them – intrigued the audience, so did the actual production process. Most of the audience had never

seen a transformer being manufactured, and a highlight of the conference was the field trip to the GE Energy transformer assembly facility in Bradenton, Florida. Another was an unforgettable trip to the Kennedy Space Center, complete with in-transit entertainment: naturally, the film Apollo 13.

The "Life of a Transformer" seminar was the brainchild of Doble Engineered Strategies Manager Richard Ladroga, who conceived it while attending the IEEE Power Engineering Society Transformer Committee meetings in Niagara Falls In October, 2000. He noticed that he was one of the youngest in the audience, prompting him to consider what the membership might look like in another 10-15 years. Most of the audience, he reasoned, might be retired and absent – along with their expertise.

The brain drain is well-documented, but that experience need not be lost. Technical conferences such as “The Life of a Transformer” help offset negative factors (the soon-retiring workforce, electric utility deregulation, corporate mergers and employee downsizing, and the loss of new power engineers to other fields such as computer science) by sharing the information, the test results, and, of course, the “crime scene data.”

The logical choice to offer this seminar, Doble has become the “epicenter of industry information” according to Ladroga. "Doble has been in the business almost as long as transformers have been made. Since we do not manufacture transformers, circuit breakers, insulators or bushings, we have always been in a position to act as a totally unbiased broker of information about their performance. “

Plans are underway for next year's event, which will attract attendees ranging from technicians to executives, engineers to consultants, asset managers to insurance underwriters, and chemists to equipment riggers. Intense and extremely practical, the conference will present a tremendous amount of information in a relatively short time, along with handouts, reference materials, and technical papers.

For more information on upcoming Doble seminars, please contact events@doble.com.

2006 CUEE FOCUS FOR KEY BUYERS IN THE INDUSTRY

Join thousands of other attendees at Canada's largest and most important utility show, CUEE 2006 on May 16-17.

- Explore 100s of exhibits, technologies and services;
- Learn about new and innovative products;
- Enjoy free networking receptions on the show floor;
- Benefit from hands-on demonstrations & expert advice;
- Participate in contest give-aways and sport activities.

CUEE show attendees are engineers, buyers and specifiers of utility-related products and services (see exhibitors list below).

Meet one-on-one with thousands of key buyers. (there were 5,530 attendees and 490 exhibitors at CUEE 2004)

De-regulation, acquisitions and mergers have created windows of opportunity in new markets for utility suppliers. CUEE will bring together key buyers for Electric, Gas and Water Utilities, Telephone, Cable TV, and more.

Take advantage of additional marketing benefits through complimentary website listings.

Located at the International Centre in Mississauga, Ontario Canada, you can learn more about CUEE 2006 by calling Bruce Roberston at (416) 269-1620 or 1-877-568-8890, or email: blr29@rogers.com .

Exhibitors at CUEE 2006

COMPANY	BOOTH#
3M	100
Abloy	916
AF Pollution	617
AGO	140,142
Allan Fyfe Equipment	O/S E + 130
Almetek Industries	506
Altec	Outside F100
AMAC	O/Side C30
Arch Wood	111
Atlantic Braids	234
Automated Solutions	216, 218
Avistar	301
Bacou-Dalloz	547
Badger Daylighting	124
Bel Volt Sales	606
Brand FX Body	Outside L6
Bronto Skylift	Outside D20
Brooklin Concrete	Outside B10
Cable Masters	500, 502
Canadian Instrument	244
Canadian Power Products	207,209,211,213
Camoplast	Outside X
Candura	512
Capella	346
CD Nova	543
Charles Jones	725,727
Commercial Equipment	347
Composite Power	O/Q + 317
Corgo Industries	308
Cross Link Tech	310
CUE Engineering Inc.	110
D & R Electronics	112,114
Daimler-Chrysler	538
DC Van	146, 148
DMC	217
Dimensions Unlimited	516
Direct Equipment	719
Drive Products	107,109
Duncan Instruments Canada Ltd.	103
Dupont Canada	417
Electric Power Assoc	206,208
Electro Rent	522
Electromark	306
Elster Metering	737
EnerSys Inc	307
Erico	524
Farmbro	800
FCI -Burndy	328, 330
Fibrobec	Outside K
Filnor Inc	119
Flir Systems	316,318
Gallo Ground Support	231
GE Infra	828, 830
G. M. Fraser	117
Grafton Utility	617 thru 724
Guelph Utility	102
Harper Diesel	523
Hazeland Mfg	517,519
Hetek Solutions	246
Ideal Pipe	409
Ilsco Canada	406
Industrial Scientific	122
IPEX Inc	419
I.T.M. Instrument	311,313
Itron Canada	400
JFC Solutions	600,602
KA Factor Group	607 thru 712
K-Line Insulators	300,302
K-Line Maint	Outddor BB
K-Tek	402
Krown	535
Lakeport Equipment	Outside I
Lakeport Power	129,131,228,230
Langford & Assoc	201, 203
LaPrairie Inc	322,324
Lightning Equipment	Outside V
Lineman's Testing	222,224
Manta Test	101
McCann Equipment	Outside J
Megger	200, 202
Millworks Mfg	423
Mobile Power	123,125
MSC	700
Nasco Inc	401
Noramco	525
North Safety	106,108
North Star	235
NYNAS Canada	518
Olameter	343
Optimum Energy	210,212
Panasonic	545
Pefco Ontario	906,908
Pengo Corp	824,826
Phoenix Mfg	503
Plastic Techniques	303
Posi-Plus Tech	Outside N
Potti Corp	113
Preformed Line Products	902,903
Pro-Tect Wear	607,609
Radiodection	717
Ranpro	747,749
RCC Electronics	820,822
RHC & Assoc	219
R L Brews	243,245, 247
Robert Hydralique	411
RPM Control	425
RS Technologies	912
Salisbury	223,225
S & C	618
Sauber Mfg	Outside H
Schneider Electric	429,431,528,530
Schweitzer Engineering	329,331
Sensors & Software	413
Shepherd's Utility	334,336,338 O/ P
Snell Canada	914
Startco	407
Stinson	143
Structural Glass	135
Super Sucker	428
Surplec	312
SWS Canada	Outside Y
Synertech	116, 118
Telvent	136
The Stresscrete	229
Thomas & Betts	634,636,638
Timberland	Outside U
Trenchless Utility	711,713,715
TS Group	725
Unirope Limited	Outside G
Velcon	403
Wajax Industries	Outside W
W.E. Enterprises	Outside R
Weidmann	309
Whelen Canada	924
Wilcox	Outside A
Williams Mobile	238
Wilson Bohannan	501
Young Utility	412

SMART METERS A WELCOME ADDITION FOR COST-CUTTING LANDLORDS

By Don Horne

Apartment building and condominium owners have faced an uphill battle convincing tenants who abuse electricity use to exercise conservation.

And in many cases, electricity costs have outstripped rent increases.

Illegal marijuana operations, people breeding reptiles and caterers who have their ovens operating around the clock all have taken advantage of the one building, one electricity bill concept.

But Ontario's smart metering initiative — designed to help reduce demand on the province's electricity grid — is also benefiting those same apartment and condo owners who are seeing their electricity costs diminish by as much as 25 per cent.

"Most apartments and condos (in Ontario) have no meters at all; but it is well-documented in parts of North America and Europe where there is sub-metering, there is at least a 20 per cent savings with individual billing," says Rob Brennan, Chief Executive Officer of Triacta Power Technologies.

Without smart metering, statistics show roughly one-third of tenants has a complete disregard for electricity costs — meaning that the remaining two-thirds are subsidizing the wasteful habits of their neighbours.

"It becomes a fairer arrangement, (utilizing) individual metering; rewarding those who conserve energy and penalizing those who waste it."

Anyone who demands more than 200 kilowatts per month in energy must have one installed in the next two to three years. By 2010, everyone demanding more than 50 kilowatts per month must have one.

Triacta Power Technologies is an Ottawa-area based company that produces the PowerHawk 6320 Smart Meter System, recently approved by Measurement Canada. The multi-tenant smart meter platform supports all time of use billing options, including seasonal and critical peak pricing scenarios. It can meter up to 20 tenants (20 single-phase or network meters, 10 three-phase meters or combinations thereof) with two-way communication capability.

According to Mr. Brennan, the one advantage of his company's smart meter is its ease of deployment — especially in retrofit situations.

"It is basically clipboard in size (16x10 inches) so it saves on wall space, and requires no rewiring," says Mr. Brennan.

One advantage for the consumer is the ability to go online and see just how much electricity they are using.

"They can log on and see their consumption," he says. "We can calculate the cost and have that emailed to the consumer. Our company has invested quite a lot in the data management and wireless technologies. At least half of our staff consists of telecommunications and IT people."

Back in May of 2003, Rob Brennan was making a presentation for a web-based monitoring system to his local utility in the Ottawa area.

The following month, he had established Triacta Power Technologies, and soon transformed his company into one of the leaders of smart metering applications.

"It all happened pretty fast; it was a very busy summer," he remembers, now very much a part of Ontario's Smart Metering initiative, providing smart meters for the condominium and apartment market in the Toronto area.

"We are working with Stratacon, providing them with individual meters for the Toronto market.

Triacta's monitor pinpoints any inefficient area by surveying each circuit of a business and providing a real-time breakdown of its energy use. This allows a business to decide which areas it needs to retrofit, whether it's a data centre, or the lighting and air conditioning systems, says Mr. Brennan.

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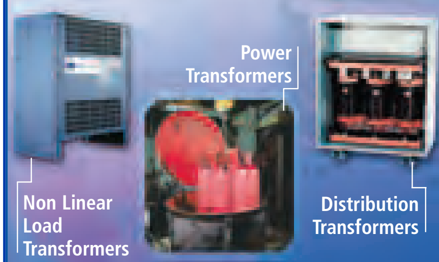

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