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In this Issue

Utility Vegetation Management

The Key Driver of System Reliability

Also

2005/2006 IEEE PES T&D p.34
2006 NATD p.58

Circle **13** on Reader Service Card

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IN THIS ISSUE

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CEA Releases Power Generation in Canada: A Guide

By: Francis Bradley, Vice-President, Canadian Electricity Association, bradley@canelect.ca

The Canadian Electricity Association has recently published a practical and educational handbook on the various generation options available in Canada. Power Generation in Canada: A Guide is aimed at a broad audience and is an important step in stimulating a society-wide discussion on Canada's electricity future. Only with a good grasp of the technologies and their range of implications can stakeholders work effectively together to meet the significant supply challenges, and create the right conditions to foster a sustainable electricity future for all Canadians.

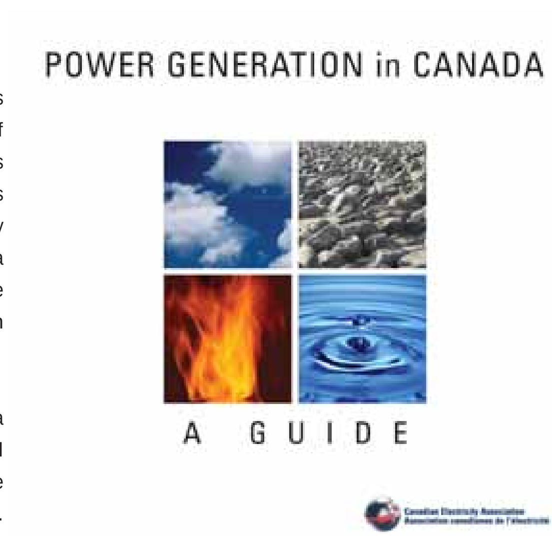
A Focus on Environmental Sustainability

A key consideration in the Guide is the environmental implication of electricity generation, as Canadians expect their increasing electricity needs to be met in an environmentally-friendly fashion. One of the key components in a prosperous economy is low-cost, reliable electricity that does not unduly burden the environment.

Governments are implementing a growing number of environmental demands on the sector through legislative regimes and international commitments. In response to these trends, the industry's environmental performance continues to improve: electricity intensity is declining, air emissions from fossil generation (coal, oil and gas) are declining; waste and hazardous materials are being reduced or more effectively managed; and species and habitat management is a bigger and bigger part of decision-making on new and existing projects.

Measuring and documenting this performance is often a challenge. To meet it, CEA, representing a majority of the country's generation, transmission and distribution assets, has undertaken a number of initiatives. CEA's Environmental Commitment and Responsibility Program, its work on climate change, mercury, and fisheries issues, and most recently its pilot studies on measuring environmental performance, are all examples.

However, a necessary precursor to measuring and documenting the performance of the industry is ensuring that the public understand just what electricity generation entails. To that end, CEA has published Power Generation in Canada: A Guide. The publication is designed to explain



the relative financial, technological, social and environmental issues for all sources of electricity – conventional and emerging. The Guide offers an overview of the issues related to each technology and an assessment of the potential of each technology to be a contributor to the 20-year generation outlook in Canada.

Decisions as to which energy options will be developed in the future are influenced by a series of criteria, some of which are examined in the Guide: future resource potential, resource distribution, technology development, environmental footprint, ability to adapt to changes in demand, and generation cost.

Canada has a large reserve of diverse, indigenous energy resources that can be used to produce electricity. These resources vary in terms of geographical and seasonal availability and development potential across Canada's regions. The use of each resource to produce electricity results in different life-cycle environmental impacts, costs and operating characteristics. Each of these factors needs to be carefully considered and balanced in developing future electricity projects in Canada.

Technological changes and development practices will have a significant impact on the continued use of conventional sources and the feasibility of using emerging technologies. To supply a dynamic and growing electricity demand over the coming decades and to adapt to changing regulatory, customer and societal expectations, Canada will need to draw upon a combination of electricity generation technologies, as well as demand-side management, to ensure a sustainable energy future for all Canadians.

Power Generation in Canada: A Guide provides an unbiased view of electricity generation options without choosing winners or losers while focusing on the electricity industry's ultimate goal: ensuring that supplies of affordable, reliable power are delivered to Canadians in an environmentally responsible way.

An electronic copy of Power Generation in Canada: A Guide as well as further information on generation options in Canada are available on the CEA Web site at www.canelect.ca. ■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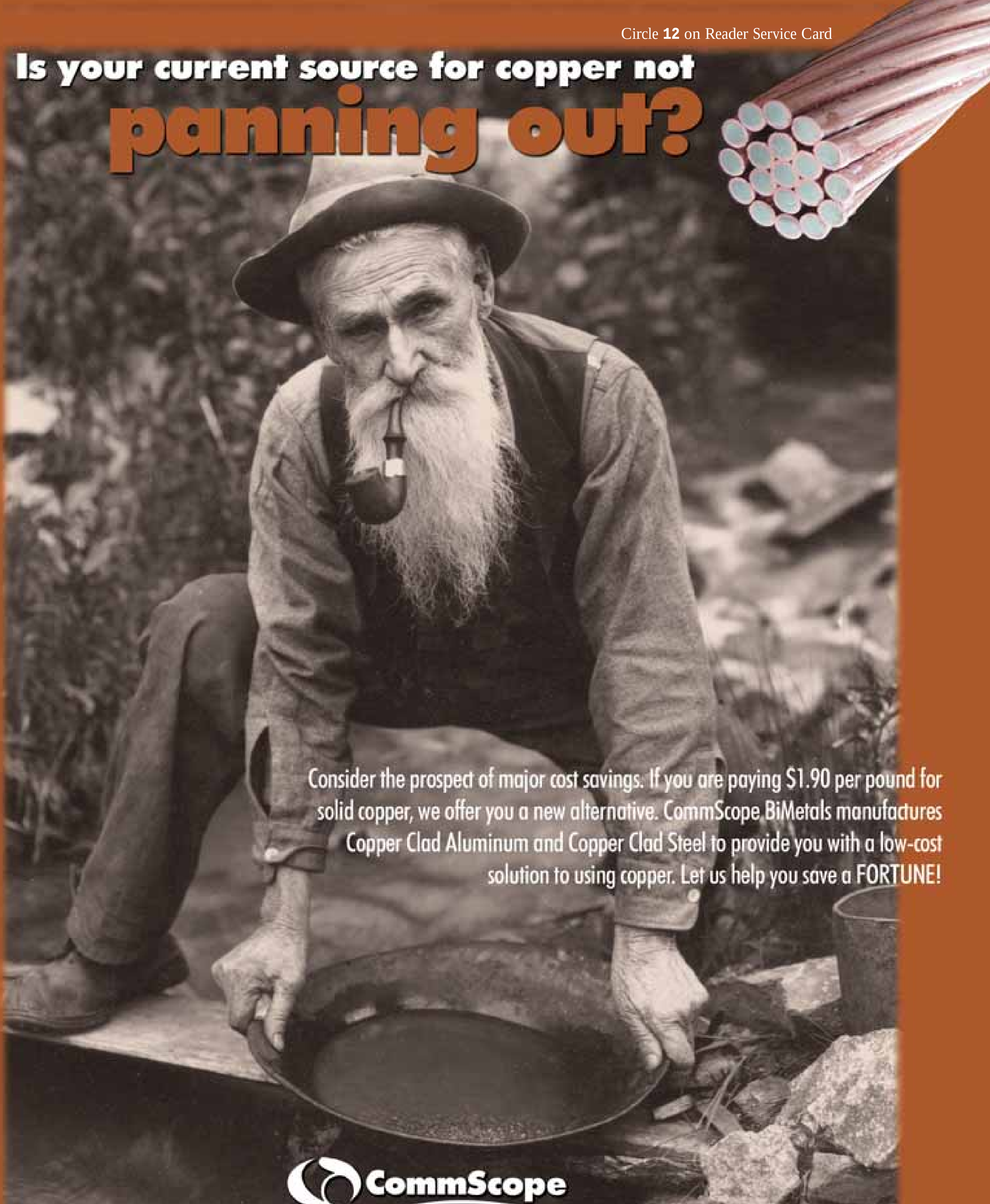
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GARRETTCOM'S NEW THERMAL DESIGN KEEPS 32-PORT MANAGED SWITCH COOL AND CLEAN

GarrettCom™ Inc.'s new Magnum™ 6K32TRC Managed Ethernet Switch builds on the Gigabit port accessibility of its companion 6K32T managed switch with the first free-convection-cooled high-port-count industrial switch. Now dusty, high-particulate-count environments such as substations and plant operational areas can benefit from more powerful Ethernet switches that eliminate the fan-failure concerns of forced-convection designs. The 6K32TRC retains the high flexibility, and low cost-per-port of the fan-cooled 6K32T, permitting up to four Gigabit (Gb) ports to be added in a number of configurations.

GarrettCom has recognized a need for both free- and forced-convection thermal designs, permitting their Magnum switches to operate reliably in a wider range of applications than manufacturers wedded to a single design strategy. Free-convection cooling is a popular design choice for small industrial switches used in high contaminant environments, but the 6K32TRC with its new static thermal design is the industry's first high-port-count, high bandwidth switch.

With the growing need for Gigabit throughput, the new 6K32TRC switch offers the greatest ease of use and bandwidth in its price class. User-selectable Gigabit transceiver modules, auto-negotiating 10/100/1000 Gigabit copper, and a variety of fiber cabling types and distances allow custom per-port flexibility.

The 6K32TRC uses the industry-leading MNS-6K software with Secure Web Manager. GUI-driven with secure web access via Secure Socket Layer, the switch provides a wide selection of security features right for today's security-conscious industrial users. The Magnum 6K32TRC Switch is available with a wide range of power options and takes up minimal space when rack-mounted.

The Magnum 6K32TRC Switch is part of a broad family line of off-the-shelf switches that all share a range of port modules configured with MNS-6K software. GarrettCom's 6K series of managed switches are designed for heavy duty applications and are NEBS and ETSI rated.

For more information on GarrettCom and its Magnum products, visit www.GarrettCom.com

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Industry News

NESCO Sales & Rentals

As of January 1, 2006 NESCO is an S.D.P. Manufacturing exclusive dealer for Indiana, Michigan, Ohio, Kentucky, Tennessee, North Carolina, South Carolina, Georgia & West Virginia.

NESCO has added to their line of Utility Equipment the EZ HAULER 3800 ranked "Best" in class, manufactured by S.D.P. This unique device is actually 5 different units in one compact machine. It can transport anything from telephone poles to transformers to and from the job site with a 3,000lbs. traveling capacity. The track driven machine can fit through areas as narrow as 36" wide, with its tracks fully retracted. This model has fully hydraulic outriggers once it reaches the job site. It also stores it's own 18" auger along the boom for easy access and manageability. The EZ HAULER 3800 has an increased horse power to 36HP and is diesel driven. It has a massive 3,800lbs. lifting capacity utilizing its crane functionality. 360 degree work zone with continuous rotation and low center of gravity also sets it apart from the rest. The 3800 has an attachable bucket like its predecessors, but has a 44' working height. Fully hydraulic pole claws and an independent hydraulic tool circuit is also equipped on this machine. This unit has a wireless remote control that not only runs its boom and winch control, but also controls its auger drive.

If you would like more information about the EZ HAULER 3800 give NESCO a call at 1-800-252-0043. We have DVD demos and you can also schedule a live demo with our sales staff. Visit our web site at www.nescosales.com.

Circle **57** on Reader Service

Opsens introduces reliable, low cost fiber optic sensor for temperature measurement in transformer.

Fiber optic sensors are a well recognized solution for helping the design and testing of transformers, as well as for online monitoring. Apart from the usual claimed temperature accuracy and accessories contingency required for transformer installations, Opsens' winding hot spot temperature monitoring system is designed to ease the installation, operation, and improve the reliability of fiber optic temperature sensors. Opsens' PowerSens system is based on well proven GaAs crystal bandgap sensors. But all GaAs sensing systems are not made equal; here are some of the features Opsens brought to this decades-old technology for addressing long awaited reliability issues.

Cabling: Fiber optic cables are one of the weakest parts of all fiber optic sensors. Minimum radius of curvature of fiber optic, and hence their robustness, is an inverse function of their diameter, meaning smaller is better. Originally of 440 Ìm OD, fiber diameter was downsized to 220 Ìm for improving robustness. Along with its actual 220 Ìm OD optical fiber, Opsens is now offering fiber optic sensors made with telecommunication industry standard optical fiber of 125 Ìm OD for further improved robustness.

Connection: Using telecommunication fiber also allows benefiting from developments arising out of this sector such as physical contact connectors. Physical contact connectors eliminate background light reflections that occur on connector interfaces. Background reflections strongly contribute to reducing measurement reliability. Weak sensors can often be saved using physical contact connectors.

Cable Handling: Fiber optic cable mishandling during transformer coil winding is still the cause of sensor damages. Opsens has developed an all-dielectric connector (TC-connector) for internal transformer uses. The sensor cable length can now be specified with much shorter length such as 0.5m. During coil winding, transport, and placement of the coil, the short sensor cable can be secured in-between coil interlayers. Once secured in the tank, the sensors are mated to the extension cable by way of the TC connector, hence reducing risks of sensor damage.

Readout Interfacing: The PowerSens includes 4x20 panel display, keypad, fully configurable relay outputs, voltage or current outputs, RS-232/RS-485 outputs with SCPI, ModBus RTU or DNP3 protocol. The system can monitor in the standard configuration up to 12 temperature sensors (optional up to 24), a single channel handheld unit the PicoPowerSens can be used in the installation of the sensors. OEM version is available.

PLEASE CONTACT OPSENS FOR INFORMATION: 418-682-9996 OR info@opsens.com

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Industry News

Solidification Products Int'l. Inc. (SPI) products Petro-Plug®, Petro-Pipe™, Petro-Barrier™, Petro Barrier™ Storm Water Boxes, provide oil spill containment from floor drains to large oil containment areas

All products are passive systems with no moving parts and allow water to filter through, but instantly seal in the event of an oil or fuel spill. Our products can be adapted to existing floor drains, refueling areas, and oil containment systems. The Petro-Plug® will fit 3 inch plus floor drains for oil spill protection. All products are patented in the United States with Canadian, and other foreign patents and trademarks pending.

SPI has over 2000 installations in the US and is branching into the Canadian market. What makes our Petro-Barrier™ systems so ideal is the simplicity of use. Our early customers had concerns about maintenance with the Petro-Barriers™ blocking with dirt and debris.

Petro-Barriers™ installed in Hydro Power Dam applications protecting highly sensitive areas

We design into all of the Petro-Barriers™ a filtering technique that allows the water continual drainage and with all of are installations water drainage has not been a problem. Small oil drips and leaks do not block the Petro-Barriers™, the media filters out sheen before discharge and only seals in an oil spill.

Petro-Pipes™ come in various sizes and have a quick clean out filter in the event of dirt build up. The Petro-Pipes™ are used for both retro -fitting and new installations for containment areas.

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SPI systems and products have been used successfully by hundreds of companies; we have the expertise to work with you for all your containment design and application needs. Visit our web site at www.oilbarriers.com or phone us at 1-800-758-3634.

Circle **59** on Reader Service

Utility Horizons™

By Michael A. Marullo, Contributing Editor

BLACKOUT!

Forget about prevention… what we need is faster recovery.

In another few months the August 2003 blackout will celebrate its third anniversary. It seems hard to believe it's been almost three years already, doesn't it? Well, let's do a quick flashback to that rather "dark" period (sorry, I just couldn't resist the pun) of history to contemplate what has happened since the biggest sustained power outage ever recorded struck indiscriminately and without warning on an unsuspecting populace… well, sort of…

First there was the shock of such a huge collapse across what was once the most reliable power grid in the world. Who could have imagined it could ever happen here? Yeah, right; no one outside the power industry maybe! But I had two different people tell me just days before the blackout – quite matter-of-factly – that such an event was probably imminent. No, I don't think they had any insider information, just a healthy dose of common sense. It's been no secret that T&D investment has been severely lacking for a long time and that deregulation has further strained an already weakened infrastructure, so for many, this hardly came as any surprise.

Let us also not forget that we'll be staring down the barrel of another long, hot summer across a large portion of the North American continent well before August arrives this year. In most areas, the drought is reaching crisis proportions, and just the other day we set an all-time record for the high temperature here for an April day: 92 degrees! Should we expect it to be cooler in July and August? On the contrary, once again this year Mother Nature appears to be setting the stage for another hot, dry summer. That usually means we'll possibly see power interruptions, rolling brownouts or – and dare I even say this – perhaps another widespread outage?

As regular readers of this column know, I live very near (what used to be) New Orleans, so long hot summers are nothing new here. However, in the aftermath of Hurricane Katrina, we now have a whole new appreciation for the effects of power outages. Indeed, the attendant problems caused by any such catastrophic event – whether triggered by natural disasters, equipment flaws, operational failures or human error – are all too well documented and still fresh in the minds of people all across the Gulf South. (We're talking about summer outages here, but of course, the threat of blizzards and ice storms will also be looming again as winter approaches in the colder parts of the Upper Midwest and Northeast.)

Yet when we look back at what has transpired since that fateful August 14th in 2003, there just haven't been many extraordinary changes that would give a reasonable person any tangible assurance that it won't happen again. Sure, there has been some progress by giving the North American Electric Reliability Council (NERC) reliability enforcement powers (i.e., whereas compliance was mainly voluntary in the past), but that certainly offers no guarantees.

Let's face it, the North American grid – though a qualified engineering marvel – is a VERY complex network, to say the least. And, it's a rule that the more complicated the network, the harder it is to model. Yet as an industry, we seem hell-bent on finding a way to prevent future outages. Hey, it's admittedly a noble undertaking that challenges the engineering mind in a way that is rarely presented. It is arguably a unique engineering problem in a lot of ways, starting with the fact that the grid is a living thing. That is, it is constantly being changed and reconfigured, and to make matters worse, it's happening at the speed of light! BUT, challenges aside, is outage prevention really where we want to bet all of our R&D chips?

This brings me to the real point of this commentary: Other than the huge (and for some, irresistible) challenge that preventing blackouts poses, why are we preoccupied with prevention when what we really need is a way to recover… faster and more efficiently? I'm not suggesting that we shouldn't be putting resources into prevention; clearly we should and in fact, we must. However, why is so little apparently being done to deal with the more pragmatic dimensions of outages: Fault detection, isolation and restoration?

More specifically, the 8/14 blackout was a certified disaster from both technical and economic perspectives. But when we put aside the political posturing and blame game that ensued immediately after the event and really examine the collateral damage, here's what we find:

- ❑ The most prolonged outages (i.e., roughly 36-38 hours) caused the majority of the economic damage since this was such a long enough period for refrigeration to be severely depleted, lines to be brought to a complete halt, backup batteries to discharge, etc.
- ❑ A substantial portion of the affected areas experienced outages that were a full order of magnitude shorter; many areas as short as a few minutes.
- ❑ Virtually no real damage to generation, transmission or distribution equipment was reported throughout the affected areas.

But, what was reported was scores of easily preventable failures that unnecessarily prolonged the outage. These were mostly failures not of equipment or tools, but rather of policies and procedures manifested by staff that had no idea how to bring their portion of the network and associated assets back up after a complete voltage collapse. Things like empty backup generator fuel tanks; broken and compromised emergency equipment; insufficient access to critical staff needed to properly manage and/or execute emergency procedures; and many other similar problems are what really kept people and businesses in the dark for the most prolonged periods.

The upshot of underscoring these failures is not to lay blame, but rather to illustrate the point that had utilities been able to identify the problems and remediate them quickly – say in a few minutes or a few hours rather than a day-and-a-half – far less economic and collateral damage would have occurred. Moreover, most people would have been far more inclined to write it off as a minor inconvenience rather than a loss worthy of litigation.

Sure, everyone would like to feel like the grid is bulletproof and that it will never fail. But when (not if) it does, wouldn't it be better to be able to recover in a few minutes rather than a few hours or days? The fact is, there is plenty of technology that has been around for a long time that can help minimize outage duration and, hence, the magnitude and intensity of the resultant losses. Why not put a greater portion of what we are currently spending on prevention and put it toward rapid recovery? After all, it's a lot easier to do the really difficult R&D with the power on than with it off. - Mike ■

Behind the Byline

Mike Marullo has been active in the automation, controls and instrumentation field for more than 35 years and is a widely published author of numerous technical articles, industry directories and market research reports. An independent consultant since 1984, he is President and Director of Research & Consulting for InfoNetrix LLC, a New Orleans-based market intelligence firm focused on Utility Automation and IT markets. Inquiries or comments about this column may be directed to Mike at MAM@InfoNetrix.com.

Utility Vegetation Management-
The Key Driver of System Reliability

Using your Utility Vegetation Management assets to drive targeted improvements to system reliability

By: Rick Hollenbaugh, founder and President of Everest Management Consultants, Inc., rick.hollenbaugh@everestmci.com
Bob Champagne, CEO of ePerformance Group International, LLC, rchampagne@epgintl.com

Utility Vegetation Management (UVM) has long represented one of the greatest opportunities for electric utilities. Not only is it the largest preventive maintenance expense in many of our nation's utilities, but it is often the greatest contributor to system reliability and outage management. Electric utilities are now looking towards optimizing how they approach the management of their Vegetation Management programs primarily due to increased regulatory scrutiny, deregulation, mergers and acquisitions and a general discontent by executive management of the overall performance of their current programs. Traditional Vegetation Management operational practices have demonstrated to be ineffective and are rapidly becoming obsolete. Electric utilities are now focusing on leveraging lessons learned and practices found both in and outside the utility in pursuit of significant bottom line impact on both cost and reliability.

The Connection between UVM and System Reliability

Federal and state regulators and utility customers have long been frustrated by the lack of consistent and appropriate reliability performance results. Federal and state agencies have been proactive in their attempts to drive increased electric utility reliability performance. The two primary areas in which these agencies are currently focusing are that of standard development and Performance Based Regulation (PBR). UVM is now being looked at as the major contributing factor in both preventing and managing utility reliability performance.

As most utility managers are well aware, August 14, 2003 represented the worst blackout on record for the U.S. and Canadian utility industries. According to the U.S. – Canada Power System Outage Task Force Final Blackout Report, the outage that occurred that day affected an area with an estimated 50 million people and 61,800 megawatts (MW) of electric load in eight states and the Canadian province of Ontario. The total cost estimates in the U.S. ranged between $4 billion and $10 billion dollars. In the Final Blackout Report, the U.S. – Canada Power System Outage Task Force identified four major outage root cause areas that included inadequate tree-trimming.

The Creation of UVM Standards

As a result of the blackout of 2003, the North American Electric Reliability Council (NERC) worked with electric utility industry experts to develop a Transmission Vegetation Management Program standard. Standard FAC-003-1 - Transmission Vegetation Management Program was adopted and is currently proposed to be effective in the second quarter of 2006.

In January 2005, the Edison Electric Institute (EEI) commissioned Davies Consulting, Inc. (DCI) to conduct The State of Reliability Regulation in the United States study detailing reliability regulation in the United States. The purpose of the study was to investigate the current state of regulation and assess the future of reliability regulation in the U.S. Through its research DCI determined that thirty-nine states and the District of Columbia have at least reliability reporting as a minimum requirement. DCI sees a shift from Return on Equity PBR to Quality of Service PBR and focus on major event-related standards as an emerging trend. Research suggested that regulators will continue to focus on PBR penalties and that Reliability Centered Maintenance may become another area of focus for regulators. According to DCI, electric utilities are returning "back to the basics" driven by heightened regulator emphasis on reliability and quality of service. DCI states, "Utilities are focusing management and financial capital on the core business of delivering electricity, which includes improving customer information systems and developing more strategic infrastructure–related

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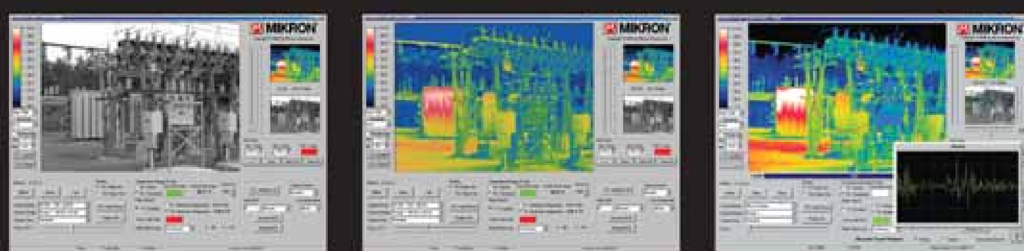

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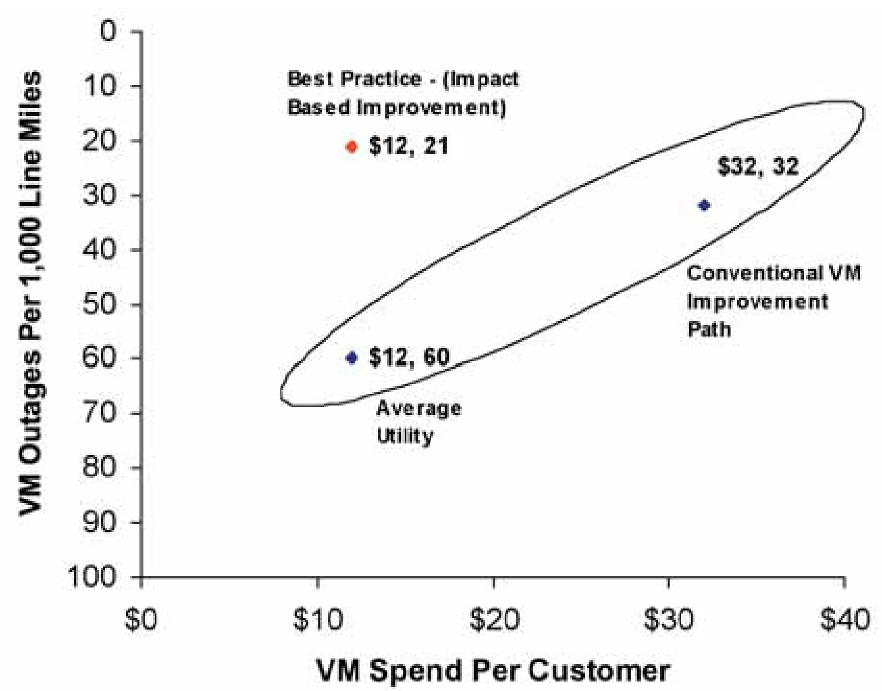
Call 1-888-506-3900 or visit us at www.mikroninfrared.com reliability investments. Furthermore, utilities have initiated strategic business process improvement initiatives aimed at sustainable cost reduction and service improvement." Reliability improvements will be essential, both from a regulatory compliance perspective, and now, due to PBR, real bottom line shareholder returns.

It is natural that UVM standards would be given much needed attention. That said, many within the electric utility industry believe that national standards and PBR will in itself drive greater UVM reliability performance. The premise being that the new PBR standards will in turn drive greater investment in UVM and the resulting improvements in system reliability.

program budgets are often cut drastically at the worst of possible times, in order to meet company earnings per share commitments or other corporate priorities. This creates an interesting dilemma- how to maintain appropriate funding to meet new reliability standards, amidst numerous demands for corporate resources.

By shifting to an impact based VM investment strategy, utilities can capture the majority of reliability improvements at significantly lower spending levels. This is demonstrated in figure 1.

Figure 1: From Conventional VM Improvement Path to Impact Based Improvement



Intuitively, this makes sense. Over the years, conventional thinking has led many regulators and executives to believe that increased investment leads to higher performance. However, there exists a clear tradeoff between spending and effectiveness. If we need to improve performance, we must be willing to make the tough decision to make UVM spending and investment the priority.

The consistency of UVM investment has been difficult to maintain. UVM programs work best when they are properly funded over a sustained period of time. Historically however, UVM

From Traditional Budgets to Strategic Spending

While there is little doubt that increased funding will drive better reliability results, it presents a serious problem for utilities from an operational and cash flow perspective. Rate restrictions and pressure from shareholders will likely prevent us from being able to fund these programs at levels necessary to remove reliability risk. One need only to look at the investment required to bring the New Orleans levee systems to Category 5 protection levels following Katrina. Investment will never be unconstrained. A better solution is needed if we are to balance reliability needs with resource constraints that will always be present. Leading organizations have begun using Asset Management principles to better tie our UVM budget to their strategic impact on system reliability.

Asset Management principles, in short, are all about how to best make use of a company's strategic assets. Originally applied in other capital intensive industries such as Airlines, Petrochemical, and Nuclear Power, Asset Management has been a major force in the strategic deployment of capital. Electric utilities are only now beginning to understand and apply these principles to the cost and reliability of its asset base. At the core of best practice asset management is the process of developing an "asset strategy" and corresponding "investment plan". It requires the enterprise to define and understand the role of each mission-critical asset in terms of downstream asset performance and return on investment (ROI). Each investment is prioritized across key risk factors and performance drivers, and given associated prioritization based on the investment's ability to drive those results. Rather than make decisions based on historical spending, investments are tied to specific risks that will have the biggest impact on system wide results.

There are several progressive electric utilities who have embraced Asset Management based decision modeling to determine appropriate long-term UVM funding requirements by linking cost to reliability. One performance-driven budgeting Asset Management methodology and tool TTM™ developed by Davies Consulting, Inc., Chevy Chase, MD has been implemented at companies such as Duke, Northeast Utilities and OG&E. These companies utilize TTM™ to determine appropriate UVM program funding levels based on required reliability performance thus driving long-term funding stability through quantifiable data analysis outputs. TTM™ allows companies to prioritize work scope based on expected reliability; provide rational for long-term funding requirements; justify long-term business planning objectives; and ultimately drive UVM program performance to deliver the "biggest bang for the buck". For example, a utility can use its actual historical cost and reliability data to develop statistically valid probability curves to determine when each specific circuit must be maintained to meet desired levels of reliability

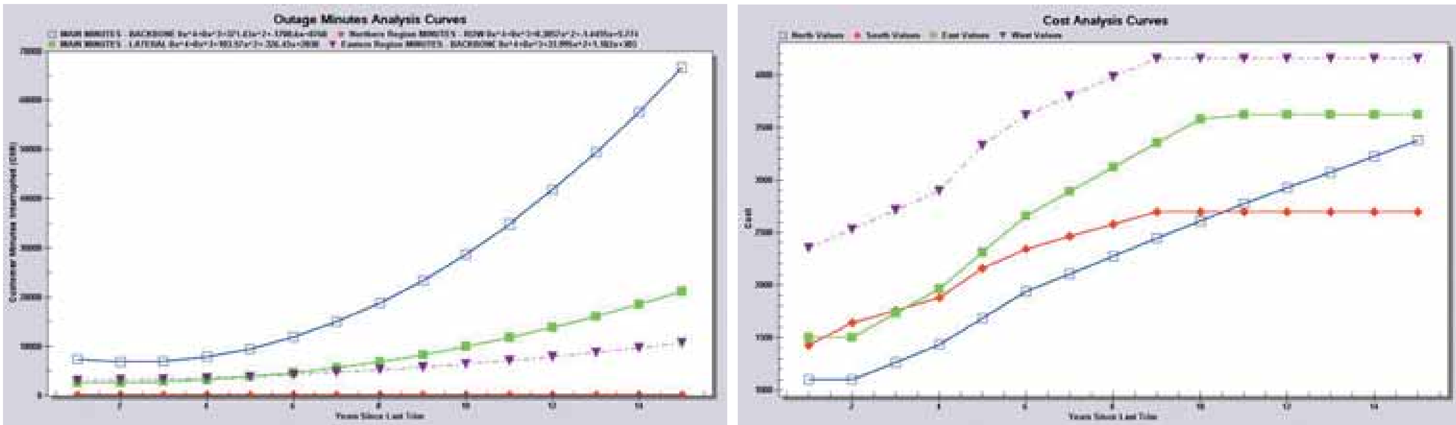


Figure 2: TTM™ cost and reliability probability curves

performance. Each circuit is prioritized and ranked based on its expected reliability payback resulting in annual work scope business plans. Figure 2 illustrates the TTM™ cost and reliability probability curves.

Tracking and Managing Performance

The UVM industry often lacks an appropriate Performance Management strategy that is adequate to drive performance in key business areas. Many UVM programs have performance metrics but what many lack is an integrated strategy linked tightly to corporate objectives. The new UVM business environment will be driven by increased utility executive, regulator and customer stakeholder performance expectations focused on reliability. Performance Management is a significant critical success factor in managing your UVM Program. The case for action to improve UVM Performance Management can be demonstrated in figure 3.

The ability of UVM programs to meet key stakeholder performance expectations consistently in the future will be based on a few performance management critical success factors. First, it is imperative that all UVM performance metrics be vertically linked to all levels of the organization, from corporate goals down through the field work force. Second, there must be a consistent, efficient and cost effective performance management process put into place and driven by fully connected data sources and consistent data analysis and reporting. This has been a historical challenge for the UVM industry. In 2005, Everest in partnership with Cyndrus, a subsidiary of NOLA Computer Services (NOLA), New Orleans, LA. and ePerformance Group International, LLC, (ePGI) New Orleans, LA.

Figure 3: Performance Management Case for Action

Performance Challenge	Current State	Future State
Lack of adequate and consistent long-term funding	Funding is based on last years budget; often changes throughout the year; short-term focused	Asset Management tools and methodologies that clearly link cost with resulting reliability
Complex organizations that continue to operate from a traditional operations and management paradigm	Costly third party contractor overhead; redundant work practices; operational work arounds negating performance improvement of root cause performance issues	Lean Project Management teams; project mangers that set expectations and manage accountability; reengineered key business processes
Vendors inability to proactively deliver continuous improvement in performance	Shrinking vendor base; short-term "bidding and buying" sourcing strategies; changing work scope and UVM planning	Sourcing strategy that uses a minimal number of long-term partnerships w/ performance based contracts
Inadequate performance management tools and strategy	UVM metrics are not always vertically linked from corporate to field; homemade systems that are complex; limited accurate benchmarking	Integrated performance management tools and strategy: increased accurate business intelligence
Lack of VM integrated regulatory, municipal and governmental strategy	Significant federal, state and local UVM maintenance barriers; ineffective "plant the right tree in the right spot" support from stakeholders	Collaborative regulatory, municipal and governmental strategy that meets expectations before pressure to change is mandated

released Everest Performance, Analysis and Report (EPAR™) system. The EPAR™ system is a state of the art performance management system focused on Utility Vegetation Management. The technology used for the EPAR™ system is currently being used by the federal government to manage government performance based contracts. This system and associated strategy has the potential to drive UVM performance management to a higher level within the industry. Figure 4 shows how performance management systems such as EPAR™ can assist utilities in driving UVM cost performance.

Additionally, it is critical that vendor performance based contracts clearly links performance to compensation. This fact is often overlooked and not easily accomplished due to the changing annual work scope and associated budget. UVM programs must also remain flexible to periodically adjust metrics and their baselines based on changing business conditions and new information learned by both utility and vendor. The performance management process must be viewed as collaborative and evergreen in that the UVM business environment and performance objectives must be continuously assessed and refined.

Finally, one of greatest UVM performance management improvement opportunities is the ability to measure and assess operational performance through a benchmarking methodology that utilizes consistent and normalized data. Today's UVM industry benchmarking processes are inherently flawed and produce poor comparative analysis primarily due to the inability to normalize data. An example of how these UVM benchmarking challenges are being overcome is demonstrated by ePGI. ePGI has developed BenchmarkCommunities, the next generation of performance management benchmarking with the development of a state-of-the-art online technology, enabling organizations worldwide instant access to performance data, information, reliable comparative databases and confidential communication to industry peers and thought leaders. It is clear that UVM performance management must include an integrated comprehensive strategy that includes appropriate systems and normalized benchmarking to assist electric utilities in driving greater UVM performance.

Project Management the Driver to Increase UVM Operational and Management Performance

One of the greatest barriers of cost effective UVM reliability performance enhancement is that of dependency on traditional UVM industry practices by UVM professionals. Many UVM programs across the country continue to operate with complex organizations delivering inconsistent performance. The key drivers in eliminating this UVM program complexity is the institution of strict Project Management practices and methodologies in conjunction with best practices found outside the UVM industry.

During 2005, Florida Power & Light's (FPL) Distribution UVM program underwent a rigorous Project Management Maturity Assessment (PMMA) that was led by Project Management Solutions, Havertown, PA and Everest Management Consultants, Inc., Doylestown, PA. This UVM program PMMA was the first of its kind in the nation and established a defined action plan to enhance system reliability and vendor productivity while reducing overall UVM program costs.

The UVM industry can look to the nuclear industry for the value of implementing best practice performance managment. During the 1990's, nuclear plant outage and maintenance duration times were significantly reduced to record number of days by instituting best practices including: Project Management; Asset Management; Cost Accounting; Performance Management; Vendor Partnerships; and First Time Quality. UVM programs must break through the traditional operational and management approches in order to perform at greater performance levels.

Next issue we will explore the UVM industry and the application of Project Management.

What does the Future Have in Store for UVM Reliability Performance?

Improving UVM industry reliability performance is complex. It involves eliminating traditional barriers, driving performance through Asset Management, incorporating new Project Management best practices and enhancing Performance Management systems and strategies. Many people thought that the 2003 Blackout would radically change the UVM

Figure 4: EPAR™ cost performance metrics

Industry and serve as the catalyst for improved reliability. However, to date this has not been the case. If fact, according to the NERC third quarter of 2005 Vegetation Management Report (fourth quarter reporting is not available at the time of this writing), the following fifteen vegetation-related outages were reported for 200 kV and higher transmission lines can be viewed in figure 5:

Figure 5: NERC third quarter of 2005 Vegetation Management Report

Voltage	Number of Tree Interruptions	Cause
230 kV	3	Tree contact from inside the right-of-way zone
345 kV	2	
500 kV	3	
765 kV	1	
230 kV	5	Tree contact from outside the right-of-way zone
500 kV	1	

Despite the recent UVM industry transmission reliability performance and specific distribution reliability challenges facing many utilities within their respective states, the industry remains vigilant. The UVM industry is working hard to meet the new UVM performance paradigm. Many have developed UVM programs that if given proper funding and governmental agency support will perform to the expectations of their greatest critics. However, it must be clear that national standards and PBR focused on improving electric reliability will not and can not be successful if implemented alone. Elimination of each UVM industry barrier identified represents the critical path to success. In closing, we remain cautiously optimistic that brighter days are ahead for the UVM Industry. In the end, if the UVM industry has the ability to successfully overcome its traditional challenges and is provided the support from key stakeholders the industry will meet the electric reliability challenges it is currently facing. In the next issue of Electric Energy T&D, we will explore how best practice Project Management applications will drive future UVM industry performance improvement.

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TWACS®
BY DCSI
Your 100%
AMI Solution
PowerStat • AMIgo™ • OASys™ • Load Control

TWACS® TECHNOLOGY

TWACS communication technology is truly unique, as it works by modulating the voltage waveform at the zero-crossing point, resulting in a communication system that uses the utility's network at the frequency for which it was designed and built. Data can be transmitted through any transformer or wiring configuration. TWACS requires no line conditioning or repeaters, and is not affected by capacitor banks, noise harmonics, feeder switching or underground to overhead transitions.

SYSTEM TECHNOLOGIES

DCSI provides utilities with a true two-way communication system and associated transponder products for AMR, Interval Data Retrieval, Dynamic Load Profiling, Time-of-Use data for Critical Peak Pricing, 20-second On-Demand Reads, Load Control and Management, Power Delivery Quality Monitoring, Prepayment, Remote Hard Disconnect/Reconnect, and Tamper/Leak/Theft Detection. In addition, the TWACS Outage Assessment System (OASys™) is available as well as Short-Hop Radio Frequency (RF) as a solution for reading proximate gas, water and pit-set meters.

ADVANCED APPLICATIONS

TWACS OASys™ technology enables outage discovery, notification of appropriate personnel before the first customer call, system-wide outage assessment and accurate monitoring of restoration progress. TWACS AMIgo™ system enables delivery of vastly increased amounts of interval data at an extremely high rate of speed by fully exploiting parallelism inherent in the electrical grid. Utilities will find that compliance with provisions of the Energy Policy Act (EPACT) of 2005 relating to advanced metering devices can be more easily satisfied with deployment of the TWACS AMIgo system. TWACS Prepaid Metering technology (PowerStat) enables utilities to offer customers the benefits of a more flexible billing approach, which will serve to provide those customers better means of managing and controlling energy expenses. Gas, water, propane and pit-set metering is enabled by utilizing the Badger Meter ORION® and TWACS RFL technologies. Since TWACS provides two-way communication to, and into, each home and business, opportunities exist for communication-based consumer services, including energy efficiency, billing options, home automation and remote site monitoring.

LOAD CONTROL

TWACS load control and interval data delivery enables a utility to meet Demand Response provisions of the 2005 Energy Policy Act. TWACS multifunctional load control enables utilities to reduce highest-cost peak demand by creating the optimum diversity of deferrable loads without impacting energy sales, resulting in improved load factor. The system avoids creation of new peaks during system automatic load restoration - under system control or upon command. The TWACS load restoration system measures effectiveness by recording whether or not load is on at the time of shed cycle. It also minimizes the impact of inrush current that follows an extended outage by initiating cold load pickup.

COMPATIBILITY

The TWACS system is compatible with most residential and commercial meters including single-phase mechanical meters produced by all major manufacturers, several solid-state electric meters in their native protocols, nearly all water/gas dial encoders, and pulse generators/initiators. TWACS management software communicates with other utility computer systems and substations and is MultiSpeak™ II compliant for billing systems interfacing.

CUSTOMERS

DCSI's customers include ATCO Electric, Bangor Hydro-Electric, Florida Power & Light Co., Idaho Power, PPL Electric Utilities, Puerto Rico Public Power Authority, TXU Energy Delivery, Wisconsin Public Service Co., and over 180 electric cooperatives and municipal utilities. PPL's project is the largest two-way AMR deployment in North America, and FPL's TWACS Load Management program is the world's largest two-way PLC Load Control project.

DCSI

Distribution Control Systems, Inc. (DCSI) is located in St. Louis, Missouri, and manufactures and markets their Two Way Automatic Communication System (TWACS®) solutions utilizing power line communications (PLC) technology for utilities deploying automatic meter reading (AMR) and advanced applications. Over 8 million two-way devices are installed or under contract.

SYSTEM EFFICIENCY & INTEGRITY

The cost-effectiveness of the TWACS system is unaffected by population density, terrain and service territory characteristics that typically limit or preclude other technology applications – and system-supporting infrastructure is already in place. The integrity of DCSI's system is an outgrowth of strategic research and development, superior design and production practices, and proactive technical service. DCSI maintains a strong avenue of communication with TWACS clients via an interactive "customer care" program and an annual Users Group conference. Whether the reason to install an automated system is operations efficiency, healthier cash flow, improved customer satisfaction, or the ability to apply multiple value-added services – deploying a TWACS system is an investment in the "future proof" tool for the industry.

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To learn more about TWACS®, call 888-892-2799. Or visit us on the web at www.twacs.com.

A POWERFUL LINE OF THINKING

Information Technology: The Antidotes For Aging Assets

By: Ron Wallace, MRO Software, Director, Industry Marketing – Utilities

Utility companies face a triple threat of aging assets, an aging workforce and legacy IT systems. The solution to these threats is a triple antidote of business process management, system consolidation and IT service management.

During the keynote address at a recent Utilities Technology Conference, the CIO for one of the largest integrated gas and electric utilities in North America said, "Information Technology is a key to future growth and will provide us with a sustainable competitive advantage." The quest to improve shareholder and customer satisfaction has lead many CIOs to reach this same conclusion – nearly all efforts to reduce costs, improve business processes and overall return on assets, both physical and human, depend on IT.

Today key business drivers include regulatory compliance, operational efficiency, aging assets and an aging workforce. Increased regulatory compliance stems from cyber security, physical security and reliability concerns affecting grid integrity, emissions, safety, and, new governance and accounting requirements. Reliability is closely linked to work and asset management in response to blackouts in 2003.

Utility industry brain drain

Aging assets and the aging workforce are also linked to technology as aging infrastructure is replaced with more technically sophisticated equipment, all capable of remote sensing and, in some cases, self diagnosis. To reduce costs, utilities need to capture the processes that long-time employees have in their heads and add these processes to business process automation tools.

The aging workforce is not an imaginary issue. According to the Bureau of Labor Statistics, the median age of utility workers is second only to workers in the oil & gas industry. The problem is further magnified by a preponderance of employees in the 45-54 year old categories. The workforce that grew up with the utility is rapidly reaching retirement age. By 2010 approximately 50% of utility workers are expected to retire. To make matters worse, utilities have instituted a number of programs to reduce staff, including early retirement incentives or layoffs.

Another study has shown that an exodus of professional staff won't be filled in key areas. Gas utility employment is projected to be down 6.2% and electric utility employment down 9.2% by 2010; coupled with a downward trend of about 10% for electric and nuclear engineers. The utility industry is especially sensitive to engineering and technical positions, as well as operations and maintenance personnel since the use of less skilled workers can impact key performance indicators, especially for safety and reliability. This "brain drain" has created the need to move business processes that are in the heads of workers into IT systems so the knowledge is preserved.

Aging assets

The workforce isn't the only aging concern in the industry. The U.S. Department of Energy reported in 2002 that the U.S. transmission system is in urgent need of modernization. The system has become congested because electricity demand keeps growings while investment in new generation facilities has not been matched by investment in new transmission facilities. Transmission problems have been compounded by the incomplete transition to fair, efficient and competitive wholesale electricity markets. Because the existing transmission system was not designed to meet present demand, daily transmission bottlenecks increase electricity costs to consumers and increase the risk of blackouts.

According to the Electric Power Research Institute, industry needs to invest $180 billion over the next 20 years on load growth, upgrading transmission lines and building the "system of the future" using new technologies to greatly improve grid reliability and provide a stable electric supply for future economic growth. And another $123 billion is needed to build out the distribution system.

A 2005 American Society of Civil Engineers report also confirmed the U.S. power transmission system is in urgent need of modernization. Despite increased demand, transmission capacity has decreased. In addition, maintenance expenditures have decreased one percent annually since 1992. In 2002, the Department of Energy stated that the existing transmission system was not designed to meet present demand, which could result in increased electricity costs to

Utility Pole News from Wolmanized® Wood

Get a Pole Warranty

When you select treated wood poles, you do not have to worry about corrosion, gentle handling, spalling, or raptor safety. And, now you don't have to be concerned about termites or rot – not for 50 years.

When purchasing Wolmanized® CCA-treated wood poles, utilities get the assurance of a 50-year limited warranty. If a warranted pole suffers structural damage from termites or fungal decay within the warranty period, you'll be reimbursed for the cost of the original pole.

For details, contact a treater or see www.wolmanizedwood.com/hd/poleswarranty.shtml.

Risk Assessment Verifies Safety

Purchasers or consumers who have concerns about the safety of CCA-treated poles can rest easy. A thorough study assessed risk to lineman and to children exposed to poles. The verdict: Intake of the critical preservative ingredient is less than the amount obtained from food and drinking water.

Printed copies of the risk assessment are available for files and distribution. A summary also appears online. Contact a Wolmanized® wood pole producer or visit the website shown below.

New NAWPC Bulletin Completed

The North American Wood Pole Council has released the latest in its informative series of technical bulletins. To see the new bulletin, "The Wood Pole 2005: Design Considerations, Benefits, and Economic Reward," or previous documents, go to www.woodpoles.org.

Southeastern Pole Conference to Meet in Tunica

A technical conference sponsored by the Southern Pressure Treaters' Association is scheduled to convene Feb. 11-13, 2007, in Tunica, Miss. For information, see www.southeasternpoleconference.org.

Wood Pole Industry Reacts

The wood pole industry is noteworthy for its outstanding response in times of emergency. A survey found that, in the 72 hours following last September's devastating Hurricane Katrina, pole producers shipped 19,200 poles (493 truckloads) to the affected area, despite plant damage, road blockages, fuel shortages, and communications difficulties. A report can be found at www.spta.org.

www.wolmanizedwood.com

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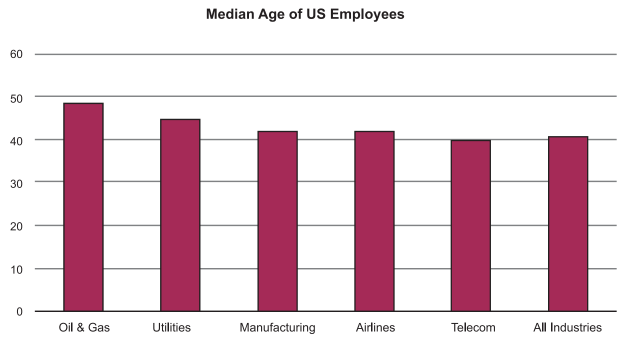
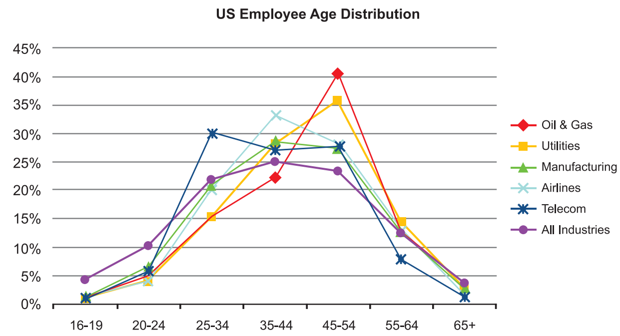




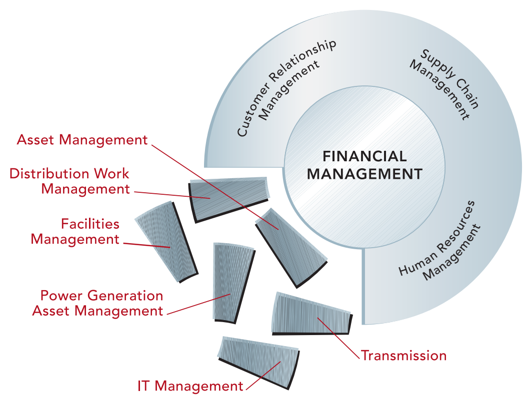
Source: U.S. Bureau of Labor Statistics, 2005

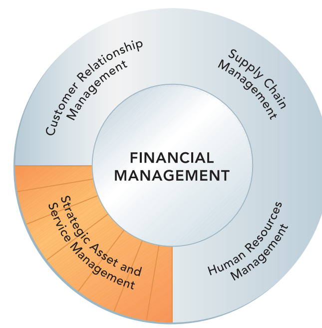
consumers and greater risk of blackouts. The August 2003 blackout cost billions of dollars in lost productivity and revenues.

The bottom line: Aging workforce and aging assets are real headaches and many utilities are counting on new information technology deployments to make workers more efficient and productive and make assets more reliable, safe and affordable.

Business Process Management

The key to solving this dilemma is to have an adaptive enterprise where agility, flexibility and top-to-bottom alignment of work processes to business goals are a core value. These processes need to be flexible so management can quickly respond to the next bump in the competitive landscape. Using standard work processes will drive desired behavior across the organization and promote the capture of asset knowledge held by many long-term employees.





A recent survey of CIOs by a leading IT research firm showed the top business issue in the utility industry was improving business processes. it is easy to see why. For most companies, business processes driving work and asset management activities are the source of the competitive advantage: risk management, revenue generation, and customer satisfaction. Standardized business processes allow management to successfully implement business transformation in an environment which may include workers acquired in a merger, workers near retirement and new workers regardless of age.

Utility executives are depending on technology-based business process management (BPM) to improve processes that allow reduced staffing levels without affecting worker safety, system reliability or customer satisfaction. These standardized and enforced processes result in common work practices throughout the organization, regardless of region or business unit. BPM, used in conjunction with system consolidation, yields an integrated set of applications that can be deployed in a rational way to improve work processes, meet regulatory requirements and reduce total cost of ownership.

How is business process management defined? BPM and workflow are often used synonymously, and while they are related, they are also distinctly different. BPM is a strategic activity for an organization looking to standardize and optimize business processes; whereas workflow is the IT solution to automate processes or the execution phase of business process management.

There are a number of core BPM capabilities that are individually strong. But when grouped together they form a solution that provides a powerful way to standardize, execute, enforce, test and continuously improve asset management business processes.

The eight capabilities are:

- Support for local process variations within a common process model
- Visual design tool
- Revision management of process definitions
- Web services interaction with other solutions
- XML-based process and escalation definitions
- Event-driven user interface interactions
- Component-based definition of processes and sub-processes
- Single engine supporting push-based (workflow) and polling-based (escalation) processes

What is the relationship between BPM and knowledge management? Research has shown the best way to capture knowledge in a worker's head into some type of system is to transfer the knowledge to systems they already use. Work and asset management systems hold job plans, operational steps, procedures, images, drawings and other documents. It is also the best place to put information required to perform a task an experience worker "just knows" how to do. With workflow and BPM, workers can be guided through a de-brief stage, where they can review existing job plans and procedures, and look for tasks not defined sufficiently to perform without the tacit knowledge the worker holds in his head. Then the procedure can be flagged for additional input by a knowledgeable craftsman. The same is true for the application itself, since the BPM tools will allow guidance to be built in with online help, or addition text to explain the next step.

System Consolidation

System consolidation is especially attractive to T&D utilities because they often have several similar, but different, systems for asset management, work management and mobile workforce management. When it comes to maximizing ROI from work and asset management software systems, using one system for all work and asset management needs delivers three money-saving benefits: productivity gains in workforce, greater asset reliability and lower total cost of ownership of the technology itself. Software systems enable organizations to improve upon current operations to: reduce cost, improve revenue generation, mitigate risk, manage regulatory compliance, and maintain a competitive edge. Bottom line: consolidated asset management systems make utilities more competitive.

One form of system consolidation involves reviewing the typical asset life cycle; i.e., where assets are engineered, constructed, operated and maintained. It's not uncommon to use two or three work and asset management systems across the life cycle. So simply moving all these applications to one platform would achieve system consolidation. However, this is just the beginning.

Consolidating applications can yield significant savings. If an organization can operate better with fewer systems and resources, everyone wins. Yet, consolidating simply for the sake of consolidation can be a no-win situation. In fact, there is a tipping point where consolidation no longer provides a meaningful return and can actually erode savings and productivity gains.

The most important part of a consolidation strategy is for the organization to understand the business processes utilized throughout, and which systems are managing those processes. Once understood, they can analyze the consolidation plans to ensure they are rational, while grouping domain expertise and like business processes. In the end, this strategy becomes a balancing act between operational excellence and system consolidation.

Overshadowed by recent focus on revenue growth and profitability, asset management has often been undermined by the lack of a single, organization-wide system capable of managing a diverse asset base. But, with cost-effective,

CONFIGURATION MANAGEMENT

Maintains All Details of Assets Through Entire Lifecycle

Understands Relationships Between Assets

Tracks Owners and Custodians

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Maximo db is the CMDB

CHANGE MANAGEMENT

Identifies and Classifies

Routes Through Correct Approval Process

Plans and Schedules All Tasks and Personnel

Standardize Process to Minimize Outages

RELEASE MANAGEMENT

Identifies and Classifies Releases

Plans and Schedules Subordinate Changes for Rollout

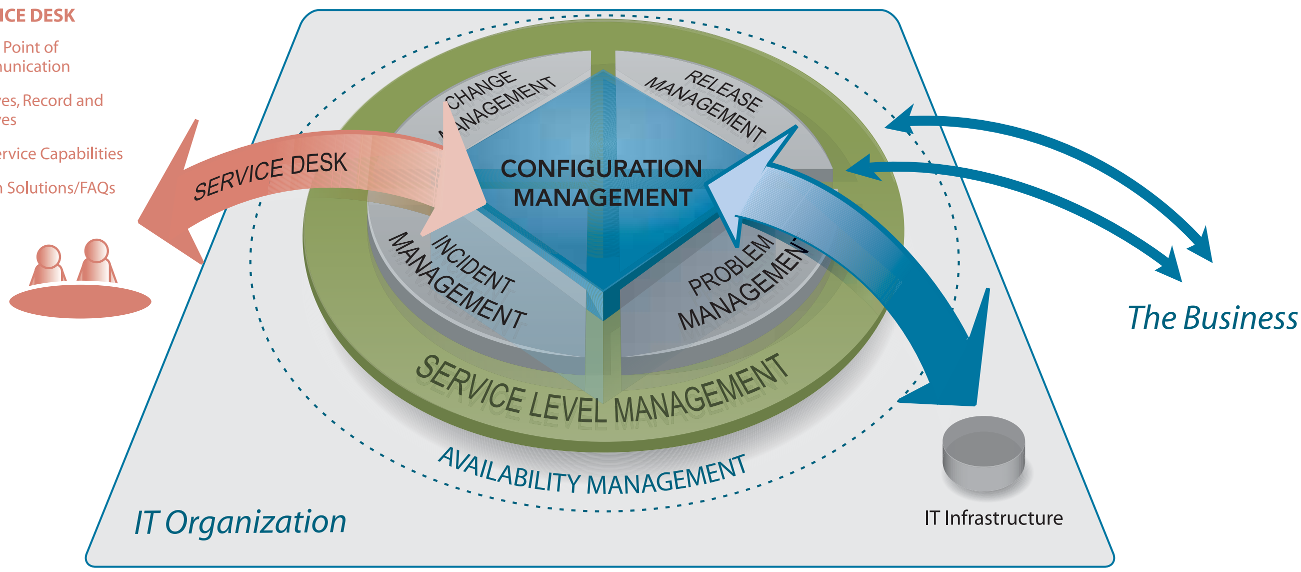
SERVICE DESK

Single Point of Communication

Receives, Record and Resolves

Self-service Capabilities

Search Solutions/FAQs



INCIDENT MANAGEMENT

Identifies, Classifies and Prioritizes Incidents

View Asset Details

Solution Searching to Improve Resolution Times

Records Details in CMBD Automatically

SERVICE LEVEL MANAGEMENT

Defines Services, Captures Agreements, Proactively Monitors Performance

Escalation Management

Any Maximo Process, Not Just Service Desk Processes

AVAILABILITY MANAGEMENT

Records Availability Metrics (Downtime)

KPIs to Ensure Availability

Escalations and Workflow to Monitor and Proactively Modify

PROBLEM MANAGEMENT

Identifies and Classifies Problems

Creates and Implements Solutions

Enables Transition from Problem to Known Error

standards-based technologies now entering the mainstream, organizations can turn to asset and service management systems to eliminate the counter-productive disparate commercial and "home-grown" systems. In essence, asset and service management is joining the enterprise application portfolio. The solution unites business processes across organizational lines where critical assets have historically been fragmented

A system consolidation strategy improves operational efficiency, lowers total cost of ownership and enables agility. Consider how many systems the average employee might touch during a typical day. Consider the maintenance mechanic who uses one system for work management, one for ordering parts, and yet another for reporting his or her time at the end of a shift? Imagine the time spent if these were three distinct systems with differing user interfaces, and the duplication of data that must occur. Imagine a streamlined process in which the mechanic utilizes one system that supports the deliverables and objectives set forth by their work requirements. A rational grouping of systems clearly enables all workers leveraging information technology to be more efficient and effective.

To understand lower TCO, consider how much it costs a company to maintain the three systems vs. one. Take into account maintenance fees, upgrade costs, integration costs and IT efficiency. IT departments can improve their service and likely lower their costs of doing so via a system consolidation program; provided they perform the balancing act of lowering cost of ownership while respecting the needs of the business (do not exceed the tipping point).

To improve agility, apply technology to create competitive advantage; finding the right pieces at the right time. A system consolidation program can move you towards an agile IT infrastructure, based upon standards, that will support the business better by providing a streamlined and integrated set of rational systems, coupled with a likely decrease in investment requirements.

In the earlier system consolidation example, the asset life cycle was consolidated, but there are additional opportunities at most utilities. In a vertical integrated utility, it's possible to use a common platform for T&D assets, generation facilities, vehicle fleets, regional distribution centers and IT assets.

And, finally, system consolidation can help eliminate the plethora of niche or rogue applications that "pop up" throughout an organization on engineers' desktops, in spreadsheets, or stand alone database. Typically, these applications are built to resolve a critical requirement or regulation where it would be too difficult to incorporate this functionality into the existing legacy systems. Using an asset management system with a modern, standards-based platform allows utilities to roll these “rogue” applications directly into their work and asset management.

A system consolidation strategy should center on core competency. To use an everyday example, accountants or dentists are both well-educated, competent service professionals. But just because they share those traits doesn’t mean you would trade one for the other just to “consolidate” the bills you receive and the checks you have to write. Think about their processes and the services they provide. You don’t want accountants filling your cavity. The same is true for your systems’ needs. Your organization’s accounting or human resource software does not possess the unique capabilities to help you manage your mission-critical transmission and distribution, facilities, vehicle fleet or IT assets.

Consolidating systems offers huge opportunities for gains in productivity, elimination of cost from the IT budget, and certainly improves an organization’s agility. It eliminates the historical drift towards stovepipe or niche systems by providing appropriate systems for critical roles and stakeholders within the organization. In effect, grouping like business processes and utilizing rational suites to eliminate duplication, waste and false prioritization due to lack of visibility, training requirements, and a host of other activities can avoid wasting critical resources like time and money.

Information Technology Service Management

The cornerstone of IT Service Management is the IT Infrastructure Library (ITIL), which refers to a set of comprehensive, consistent and coherent codes of best practice for Information Technology Service Management (ITSM). The objective for developing ITSM is to increase the business effectiveness of the Information Technology (IT) organization, while maintaining or improving IT services. The ITIL concepts provide a structure for service-oriented best practices. They are used as a benchmark for organizations attempting to measure the quality of ITSM. Key components of the ITIL best practices include configuration management, incident management, problem management, change management and service level management.

- Configuration Management is the process of identifying, recording and reporting on all IT components.

- Incident Management is the process of restoring normal service operation as quickly as possible in order to minimize the adverse impact on business operations.

- Problem Management is the process of minimizing the adverse impact of incidents and problems caused by errors in the organization’s infrastructure on the business, and to prevent recurrence of incidents related to these errors.

- Change Management is the process of ensuring that standardized methods and procedures are used for efficient and prompt handling of all changes—the goal being to minimize the risk of change-related incidents and improve day-to-day operations.

- Service Level Management is the process of maintaining and improving service quality through a constant cycle of agreeing, monitoring and reporting to meet the customers’ business objectives. Successful Service Level Management depends upon the planning and implementation of service level agreements (SLAs); essentially contracts between business units or the organization and its customers, which guarantee a service deliverable in quantitative terms.

Let’s face it: your utility is going to be using more complex technology-based systems to operate and maintain assets today and into the future. None of these systems stands alone and to gain the most advantage from your business systems it is strategically imperative that you deploy an IT service management system whose mission is to keep your mission-critical business and operational systems up and running. This should be part of your strategy, because only by cost effectively maintaining these new technology-based systems will you be able to recognize the benefits that your need to bring to the bottom line. ■

Maintenance of MV & HV Power Circuit breakers

By: Fouad Brikci, Ph.D., Zensol Automation Inc.
By: Emile Nasrallah, P.Eng., Circuit Breaker Specialist

Preface

This article is the first in a series of articles that will help to bring light to the maintenance practices presently applied to power circuit breakers.

A list of the most popular tests used; with reference to the international standards compliance, is included at the end. Each test provides a bit of information that is complementary to the others, providing a general overview of the circuit breakers testing practices.

A circuit breaker is an important equipment to power electric networks. Its importance is due to the protection role it is playing. Hence, it is imperative to assure its proper operation. This is only possible by applying suitable maintenance.

The main purpose is to help us understand, accurately, the real condition of the breaker being tested thus helping targeting the corrective actions. This targeting helps minimize maintenance spending and increase network reliability, hence leading to efficient network management.

Introduction

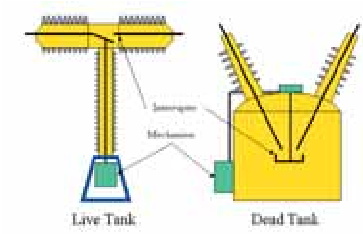
A power circuit breaker is equipment intended to switch on and off electric currents on power transmission and distribution networks for routine operations and protection of other equipment.

Electric transmission system breakups and equipment destruction can occur if a circuit breaker fails to operate because of a lack of preventive maintenance.

Description

Its name, circuit breaker, indicates clearly its role. It breaks electric circuits. To achieve this purpose, it separates mechanically two points in the circuit to a certain distance large enough to break the flow of electric currents.

Circuit breakers come in a great variety and use different technologies:



LIVE TANK: Minimum oil, Air blast, SF6 etc.
DEAD TANK: Bulk oil, SF6 etc.

Despite the big difference all types share common principals, they all have to provide two main functionalities highly related:

- Electrical functionality (Interrupter).
- Mechanical functionality (Mechanism).

Electrical functionality

Circuit breakers are designed to satisfy predetermined breaking conditions and have electrical properties that can be resumed by the following:

- Current carrying property;
- Insulating property;
- Current breaking property.

Mechanical functionality

The requested electrical properties imposes mechanical properties that can be more or less demanding depending on the used technology:

Current carrying property imposes:

- Contact material that is highly conductive;
- High quality of contact make;
- Low contact reaction to ambient atmosphere and temperature.

Insulating property, depending on the voltage level imposes:

- The contacts parting distance in open position;
- Line to ground distance;
- Characteristics of the insulating medium and reaction over time

Current breaking & making properties, imposes:

- The speed of the opening or closing contacts;
- Arc blowing techniques;
- Resistant to arc material;
- Energy required to carry on the breaking or making of large short circuit currents;
- Characteristics of the insulating medium and reaction over time and frequency of current interruption.

Frequency of operation property, influences greatly all the above-mentioned parameters.

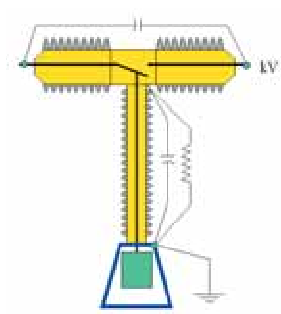


Fig 5

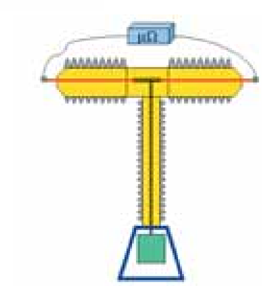


Fig 3

Preventive maintenance

The need for maintenance of circuit breakers is often not obvious, as circuit breakers may remain idle, either open or closed, for long periods of time. The need to predict the proper function of circuit breakers grew over the years as transmission networks expanded and carried increasing energy to longer distances.

The technology advance over the years brought low maintenance breakers but it did not bring more reassurance to network management as to the reliability of operation.

The circuit breaker is, in fact, a black box. The only way to be sure of its condition is to open it for physical inspection. Unfortunately, this way is costly and must be reduced to minimum to prevent unnecessarily maintenance.

Predictive maintenance

Maintenance people created what is now widely known as the predictive maintenance. The purpose is to predict accurately the condition of the breaker, without having to open it for inspection.

Required open inspection would then be limited to corrective or preventive intervention, thus reducing dramatically the cost of maintenance and increasing to the same level its efficiency.

The prediction can take three ways complementary to each other:

TESTING: a wide range of tests where invented to verify the conformity of each of the electrical and mechanical properties to meet the design criteria. Some of these tests are acknowledged and documented by international standards (IEC, ASTM, etc.). Some are still under development and promise great expectations.

MONITORING: continuous surveillance of the breaker by the means of multitude transducers controlled by a computer. Alarms or actions are triggered when settings are reached thus permitting just in time intervention. This way is still under development and is very promising.

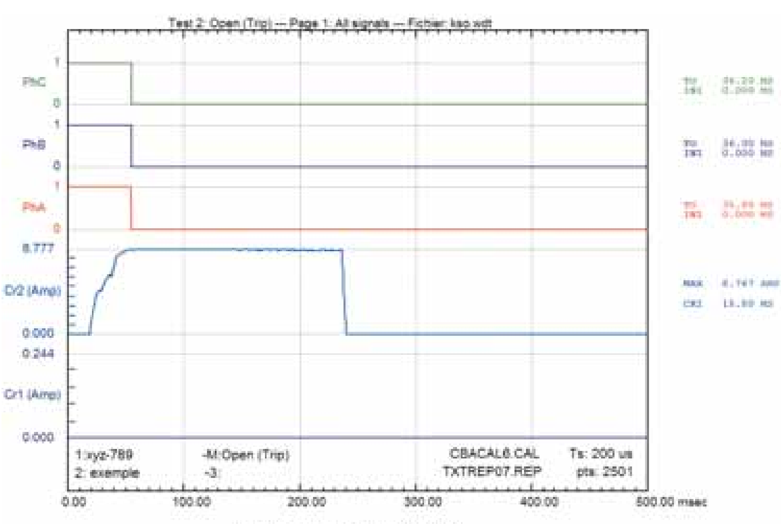
STATISTIC STUDY: continuous measurements, samplings and maintenance interventions, are noted over the years on each breaker. This information assembled in databases, helps conduct statistic studies aiming to target the faulty components or helps a probabilistic modeling of aging in Circuit Breakers for Maintenance.

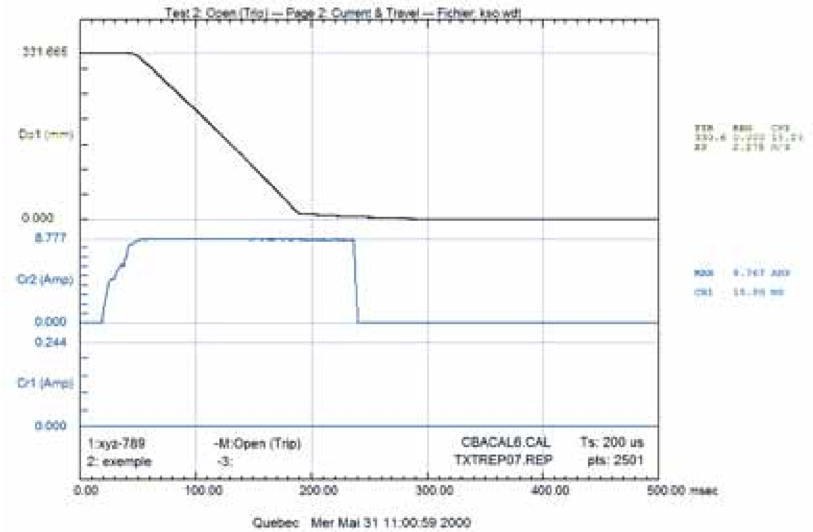
A practice widely spreading by network administrators, is to require for each type of new breaker a statistic study from the supplier on the reliability of the new equipment components, based on their own experience. This will help to focus the maintenance actions on the most vulnerable parts.

Safety Practices

Maintenance procedures have to respect the safety practices and the following points require special attention:

a) Be sure the circuit breaker and its mechanism are disconnected from all electric power, both high voltage and control voltage, before it is inspected or repaired.





b) Exhaust the pressure from air receiver of any compressed air circuit breaker before it is inspected or repaired.

c) After the circuit breaker has been disconnected from the electrical power, attach the grounding leads properly before touching any of the circuit breaker parts.

d) Do no lay tools down on the equipment while working on it as they may be forgotten when the equipment is placed back in service.

Breaker testing

Maintenance tests enable personnel to determine if breakers are able to perform their basic circuit protective functions.

The tests mentioned in the following table of tests, may be performed during routine maintenance and are aimed at assuring that the breakers are functionally operable. These tests are to be made only on breakers and equipment that are deenergized.

The table of tests lists the tests and their purposes, regrouped by the purpose category (Mechanical, Electrical, Chemical).

In general, to conduct a successful test, the following conditions has to be observed:

- Application procedure (provided by the test equipment provider);
- Design specifications with defined tolerances (provided by the breaker designer);
- The breaker instruction book and related outline, basic and elementary drawings (provided by the breaker designer);
- The international standards definitions and specifications if required by the test.
- Good sense of analysis

Maintenance Program

The same need to predict the proper function of circuit breakers that created the predictive maintenance, and since it is not feasible to test indefinitely the circuit breakers, it was obvious to structure the maintenance acts in a maintenance program that defines the maintenance actions and frequency.

Most of breaker manufacturers recommend maintenance programs that suit better their equipment. They generally define three levels:

1- Routine inspection: includes:

- Visual inspection of the outer shape of the equipment.
- Checking the operation counters.
- Checking the pressure gauges.
- Detecting visual or audible leaks.
- Measuring temperature.
- Etc.

This is done with the breaker in service.
Frequency: generally 6 months to 1 year

2- Minor maintenance: Includes, in addition to the routine inspection:

- Thorough inspection of the state and function of subassemblies,
- Breaker testing
- Minor interventions to replace easy access ware parts,
- Changing filters, oil or gas etc.

This needs to isolate the breaker from the network.
Frequency: generally 6 to 8 years

3- Major maintenance: Includes, in addition to the minor maintenance, opening the major assemblies to access internal parts:

- Interrupter;
- Mechanism;
- Tank receiver.

This needs to isolate the breaker from the network.

Frequency: depends on breakers technology (12 years for air blast, 20 years for SF6, etc.)

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UNITED STATES DEPARTMENT OF THE INTERIOR BUREAU OF RECLAMATION DENVER, COLORADO.

About the Authors

Dr. Fouad Brikci *is the president of Zensol Automation Inc. He was the first to introduce the concept of truly-computerized test equipment in the field of circuit breaker analyzers. As a former university teacher in Ecole Polytechnique — Algiers and CNRS - LAAS researcher in France, Dr. Brikci has developed experience in the fields of electronics, automation, and computer science. Most activities were focused on the industrial application of computers. Among his achievements are the development of fully comput¬erized measuring systems for quality control in circuit breaker manufacturing, laboratories, and maintenance services of electric utilities. Dr. Brikci holds a PhD in Electronics and a Master in Sci¬ences in EEA (electronics, electrotechnics, and automation) from the University of Bordeaux, France.*
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Emile Nasrallah *is an electrical engineer specialized in Power circuit breakers maintenance. Since graduation in 1984 he worked as a field engineer. In1990 he joined the worldwide circuit breaker manufacturer GEC ALSTHOM as a specialized field engineer.*
In 1997 he became the manager of MV & HV circuit breaker SF6 division of ALSTOM, responsible of technical support, maintenance and training for SF6 circuit breakers. In 2001 he became manager of Air blast circuit breaker division for AREVA. He was in charge of the Air blast (PK and PKV) refurbishing program in partnership with hydro-Quebec and introduced a unique administration system for the program (average of 35, 735 kV PK air blast circuit breaker per year). In 2005 he joined General Electric Company of Canada as a senior circuit breaker specialist and is in charge of the circuit breaker division of the Montreal service centre, responsible of the remanufacturing program for Oil circuit breakers

No	Name	Description	Breaker Type	Application	Standards	Figure
1	ContactTiming Test	Measures the time fromthe order initation to contacts close or part	All	Mechanical: Overall breaker operation	IEC56, art4.113	Fig 1
2	Travel & Velocity Test	Traces travel and velocity curves	All	Mechanical: Overall breaker operation	Design	Fig 2
3	Functional Test	Cheks the general operation of the breaker	All	Mechanical: Overall breaker operation	IEC694, art7.2.2	
4	Vibration Test	Measures the vibration signature of a circuit breaker	All	Mechanical: Overall breaker Integrity		
5	First Trip Test	Measures the contact timing at first trip	MV breakers	Mechanical: Overall breaker operation		
6	Operation pressure consumption Test	Measures the air consumption of an operation or cycle of operations	Pneumatic & Hydraulic breakers	Mechanical: Overall breaker operation		
7	X Ray Test	Takes an X-ray photo of the inside of closed subassemblie	All	Mechanical: Overall breaker Integrity		
8	Ultrasound Test	Cheks Microcrackes in insulatures	Insulators	Mechanical: Overall breaker Integrity		
9	Contact Resistance Test	Measures the contact resistance between to parts meant to conduct current	All	Electrical: Main Circuit conductivity	IEC694, art7.3	Fig 3
10	Dynamic Contact resistance Test	Measures the contact resistance continously since the first contact make of a moving contact until the contact's	All	Electrical: Main Circuit conductivity		
11	AC Insulation Test	Measures the insulation between open contacts and between line and ground	All	Electrical: Main circuit Insulation	Very Popula	Fig 5
12	Infrared Temperature Test	Measures temperature of parts by infrared device	All	Electrical: Main Circuit conductivity		
13	Auxiliary Circuits Insulation Test	Measures the insulation of the low voltage control circuits	All	Electrical: Control circuits insulation	IEC694, art7.2	
14	Capacitance Test	Checks the capacitance value on capacitors used on breaker (grading, coupling, etc.)	Capacitors	Electrical : Equipment Integrity		
15	SF6 Mixture percentage Test	Measure the percentage of SF6 in insulation gas mixture	SF6 breakers	Chemical: General quality of medium		
16	SF6 By-Products Test	Measures SF6 byproducts level in SF6 insulation gas	SF6 breakers	Chemical: General quality of medium		
17	Water Content in gasTest	Measures the moisture content in the insulation medium	Air Blast & SF6	Chemical: General quality of medium		
18	Tightness Test	Checks the tightness of the insulation medium	All	Chemical: General quality of medium	IEC694, art7.4	
19	Oil dissolved gas analysis Test	Measures the gas content in the insulation oil	Oil breakers	Chemical: General quality of medium	ASTM; D3612	
20	Oil Dielectric Test	Measures the dielectric carachteristics of insulation oil	Oil breakers	Chemical: General quality of medium	IEC156; ASTM: D877,	
21	Oil Acidity test	Measures the degree of acidity in insulation oil	Oil breakers	Chemical: General quality of medium	ASTM: D974	
22	Oil interfacial tension	Measures the interfacial tension of insulation oil (for particles in oil)	Oil breakers	Chemical: General quality of medium	ASTM: D971	
23	Oil Power Factor	Measures the power factor	Oil breakers	Chemical: General quality of medium	ASTM: D924	
24	Water in Oil	Measures the PPM of Water in Oil	Oil breakers	Chemical: General quality of medium	ASTM: D1533	
25	Oil Density	Measures the density	Oil breakers	Chemical: General quality of medium	ASTM: D1298	

Why You Need to Be There…Now More Than Ever

Welcome to the dynamic and burgeoning city of Dallas and the **2005/2006 IEEE PES Transmission and Distribution Conference and Exposition**. As has been the tradition in the past, this IEEE PES event will present the information and detail necessary to manage technology and business solutions in the years ahead. It will present the future of our industry through an outstanding compilation of technical and business sessions, special presentations and exhibit displays.

We are pleased and excited about this year's program and schedule of events. Our host committees, located in New Orleans (Entergy) and here is Dallas (TXU Electric Delivery) have put together an exceptional menu of technical and business-related topics.

Industry experts and recognized authorities will be sharing their expertise and impressions of the changes and challenges that lie ahead. There is an overwhelming amount of material to assimilate and absorb for both first-timers and seasoned veterans.

The Landscape of the Future

We know that the next few years will be increasingly volatile as the electric utility industry continues to move through a period of reacquainting itself with an improvement in the management of its infrastructure and operations.

There is little doubt that the landscape of today's electric utility is being altered and the traditional operating procedures are continually in review. Many companies realize that they can no longer continue with business as usual.

All forms of technology and the knowledge and expertise gained through the application of that technology is the key to electric utilities successfully sustaining and maintaining and building their utility business and customer base in the future.

Whether it is through the implementation of leading edge or tried-and-true technology, effectively using technology improves productivity while at the same time enriching job fulfillment.

As we implement new and exciting improvements we have learned that human intelligence and intellectual resources are any utility's most valuable asset. And that knowledge applied to work creates value. The utility of this decade and beyond will require the employee to be an innovator, troubleshooter and knowledge worker.

This year's **2005/2006 IEEE PES Transmission and Distribution Conference and Exposition** is designed to offer electric utility personnel and other interested attendees answers to complicated questions by thoroughly engaging them in a conference program and an exposition that displays the industry's newest technology products and concepts.

This year's conference and exposition promises to be the most important in its history. Never before has the electric utility industry faced so many monumental challenges. Our theme, "*Join the Parade of Technology*" is an idea that utilities must understand and adopt if they are to be successful in the future.

Providing Solutions to Your Problems

Thousands of attendees from across the United States and around the world will arrive in Dallas to participate in the world's largest transmission and distribution event. Many of the attendees are in search of answers their most pressing problems. The focus of a majority of the attendees at the event will be on electric utility technology.

As an attendee you will gain authoritative analysis and critical insight into the issues you now face. The IEEE PES 2005/2006 event is an intensive learning experience and an ideal opportunity to build valuable relationships with your colleagues and experts from around the world who are interested in improving their base of knowledge.

From our unique Opening Session, scheduled at 8:00 am on Monday, May 22, through to our Closing Ceremony and Reception on Wednesday, May 24, the technical and business program examines the business solutions and methods and procedures for operating and maintaining power-delivery systems at peak levels.

The show can be used to move your utility ahead. Over the years, the show has evolved to become a process technology event filled with innovations that involve the latest systems technologies that will allow you to manage operation more effectively.

This year's event is organized to provide attendees with an event that concentrates on the world of transmission and distribution and all of its elements—a focused yet thoroughly comprehensive forum that will draw the highest attendance of professionals from around the world.

Electric utility professionals have discovered that the IEEE PES Transmission and Distribution Conference and Exposition is an essential means of accomplishing the goal of reaching and establishing face-to face contact with their peer group.

Every utility manager and operating professional who is interested in remaining on e step ahead of the challenges of tomorrow should plan now to participate in the power delivery industry's most powerfully event. Every attendee is making Dallas the headquarters of a knowledge-building experience in May 2006.

All of the volunteers who have planned and organized the hundreds of presentations and activities look forward to welcoming you.

Sincerely,

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Sponsoring TXU Electric Delivery Executive
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Randy Helmick
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Hawk IR International	319
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Company	Booth
Kanohar Electricals Ltd./Kuhlman Electric	3641
KEC International	3956
Kelman	3825
KEMA	2415
KEPCO - Korean Pavilion	4015
Key Bellevilles, Inc.	657
Kinectrics	1858
Kirk Key Interlock Company	2727
KMG-Bernuth, Inc.	4060
Konnext Inc.	317
Koontz-Wagner Electric Company	923
Korea Electric Power Corporation	4119
Korea Electrotechnology Research Institute (KERI)	1055
Kortick Manufacturing	3156
Krenz and Company Inc.	1124
Kuhlman Electric Corporation	3641
Kysor Panel Systems	748
LaMarche Manufacturing Company	3015
Laminated Wood Systems, Inc.	1954
Landis + Gyr Inc.	720
LAPP Insulator Company LLC	3341
Laser Technology	715
Lerro Corporation, The	4141
Light Star	4017
Lindsey Manufacturing Company	2721
LinearVision, LLC	557
Loresco Inc.	1207
LS Cable	352
Luxtron Corporation	329
MacLean Power Systems	1115
Magnetic Technologies Corporation	831
Manitoba HVDC Research Centre	347
Manitoba Hydro International	347
Manitoba Hydro Laboratories	347
Manta Test Systems Inc.	1058
Mass Int'l / Demirer Kablo	455
Mastec Energy Services	3053
Maxwell Technologies SA	622
Maysteel LLC	3841
MCMI -MCM International Inc.	4052
MCR Safety	755
MCW/AGE Power Consultants	3455
Megabras	2656
Megger	2331
Mehta Tech, Inc.	1760
Menk-USA, LLC	4041
MGM Transformer Company	655
Microhard Systems Inc.	3821
MicroPlanet	970
Microwave Data Systems, Inc.	348
Midsun Group Inc.	854
Mikron Infrared, Inc.	4115
Milbank Manufacturing Company	2226
Milsoft Utility Solutions	2651
Mitsubishi Electric Power Products,Inc.	2241
Modern Insulator Limited	3651
Moloney Electric	2021
MPHusky Corporation	1827
MSE HEXA Core	4137
MSE Power Systems, Inc.	3025
Multicircuits	3759
Myers Power Products, Inc.	4031
Namsung Industries	4027
Nantong Shenma Electric Technology Co., Ltd.	3814
NASCO Industries, Inc.	1566
National Material Company	2958
National Strand Products, Inc.	2042
NEETRAC/Georgia Tech	2422
Neoptix Fiber Optic Sensors	1018
Neptco Inc.	3823
Network Mapping Limited	1263
New River Electrical Corporation	554
Newell-PSN LLC	523
Nexans	341
Niagara Transformer Corporation	307
Nippon Kouatsu Electric Co., Ltd.	3716
Nix of America	353
NJUNS, Inc.	1257
NOJA Power Switchgear Pty Ltd.	2852
Nolan Power Group LLC	1655
Noram SMC. Inc	1353
Nordic Fiberglass, Inc.	2841
North American Galvanizing Company	3927
North American Wood Pole Coalition	1514
NovaTech, LLC	3515
Novinium, Inc.	961
NRECA TechAdvantage 2007 Expo	2125
NSi Industries, LLC	3654
NURI Telecom	4118
NxtPhase	2714
Nynas USA, Inc.	817
Ofil Ltd.	2620
Ohio Brass (Hubbell Power Systems)	1441
Okonite Company, The	823
Omicron Electronics Corp. USA	1841
On-Line Monitoring Inc.	2025
Open Systems International, Inc.	3215
Operation Technology Inc.	457
Opsens Inc.	1821
Optimal Geomatics, Inc.	3014
Optisense Network Inc.	3161
Origo Corporation	3158
Orto De Mexico, S.A. De C.V.	333
OSIsoft	4018
Osmose Utilities Services, Inc.	1149
Ox Creek Energy Association Inc.	3917
P & R Technologies	615
Palmer Wahl Instruments	3661
Park Electric Company	1154

Company	Booth
Partner Technologies Inc (PTI)	3831
Passoni & Villa SpA	956
Pauwels Canada Inc.	3631
Pauwels Contracting Inc.	3631
Pauwels International N V	3631
PBP-Preissinger/Electromech	808
PCORE Electric Company	949
Peak Power Engineering	3157
PenCell Plastics, Inc.	1941
Penn-Union Corporation	3560
Pennington Crossarm Company	1914
PennSummit Tubular	2559
Pennsylvania Transformer Technology, Inc.	3349
Performance Pipe	2621
Phenix Technologies, Inc.	1307
Phoenix Electric Corporation	641
Phoenix International A/S	1357
Piedmont Bushings and Insulators, LLC	1661
Plymouth Rubber Company, Inc.-Plymouth/ Bishop Division	2615
PNA/API	3657
PNM	1065
Polaris Connectors	1755
Pondera Engineers	2224
Positron Industries Inc.	418
Post Glover Resistors, Inc.	1059
Powel-MiniMax Corporation	1049
Powell Industries, Inc.	913
Power Asset Recovery Corporation	1866
Power Delivery Products, Inc.	3152
Power Engineers, Inc.	2251
Power Line Hardware Company	318
Power Line Systems, Inc	2040
Power Measurement	1616
Power Monitors, Inc. (PMI)	441
Power Quality Systems	3948
Power Substations Inc.	452
Power Transmission Solutions, Inc	755
Powerlineman.com LLC	2357
Powerohm Resistors, Inc.	3622
Powertech Labs Inc.	2850
PPC Insulators	1759
Preformed Line Products Company	541
Premax	2521
Procom System	4019
ProGlass, Inc.	960
Prometek Inc.	1054
Prysmian Cables & Systems	2418
PT Technologies	619
Pucaro Electro-Isollerstoffe	1557
QEI, Inc.	1352
QualiTROL Corporation	741
Quanta Services	3815
Radar Engineers	522
Rahemo, S.L.	2248
Raytech USA, Inc.	2225
Realtime Utility Engineers	2141
Reinhausen Manufacturing Inc.	1315
Reuel Inc.	2449
Rezzak Copper	957
RFL Electronics Inc.	2914
RH Systems	2861
RHM International	3418
Richards ManufacturingCompany Sales, Inc.	933
Ripley Company	718
Ripley Photocontrols Div of SouthConn Technologies, Inc.	1523
Ritz Instrument Transformers, Inc	3933
Roechling Machined Plastics	1519
RS Technologies	3218
RTDS Technologies Inc.	1549

Company	Booth
RTE	3947
RuggedCom Inc.	447
Rural Electrification Magazine	2127
S&C Electric Company	3040
Sabre Tubular Structures	1808
Sadem	1253
Sadtem/LaPrairie Inc.	1253
Saft America, Inc.	359
SALCO Inc.	2858
Sam Dong Co., Ltd.	3941
Sargent & Lundy,LLC	1525
Satec, Inc.	1754
Schonstedt Instrument Company	809
Schweitzer Engineering Laboratories, Inc	1531
Schweitzer Engineering Laboratories, Inc	4153
Secucontrol Inc.	1622
Sediver Canada	549
SEFCOR, Inc.	2627
Sensa,	1767
SensorLink Corporation	1421
SensorTran	2755
Seochang Electric Communication	4025
Serveron Corporation	1659
Shakespeare Composite Structures	3125
Shallbetter, Inc.	3624
Shallco	521
Shanghai Huaming Power Equipment Co., Ltd.	2859
Shermco Industries, Inc.	4135
Shijiazhuang Hwaneng Electric Co.	2558
Siba Fuses	1859
Sicame Corporation	2030
Siemens Power Transmission & Distribution, Inc	625
Sievert Industries, Inc.	717
Sigama Machining and Favrication Ltee`	1664
Slingco Limited	1856
SlipNOT Metal Safety Flooring	2918
SMC Electrical Products	1849
Smit Transformers Sales, Inc.	1919
Solidification Products Int'l. Inc.	2722
Solon Manufacturing Company	1609
Southern Electrical Equipment Company - SEECO	3953
Southern States, LLC	1040
Southwire Company	433
Spintelligent/Metering Interntional	3461
Sprint Nextel	3514
St. Louis Screw & Bolt	3456
Stalcop L.P.	3159
Stanley Consultants, Inc.	2316
Startco Engineering Ltd.	3920
Steel Grip Inc.	414
Stratos	560
Strongwell	3751
Subnet Solutions Inc.	1624
Sunrise Technologies	2321
Superior Cables USA Ltd.	559
Supreme & Company	3522
Survalent Technology	2215
Synertech Moulded Products Inc.	2823
T & D World Magazine	2051
T & R Electric Supply Company, Inc.	915
Taihan Electric USA., Ltd.	3056
TAMINI Transformers	2414
Taylor-Made Communications, Inc.	3018
TBEA	3357
Tech Products, Inc.	1854
Techimp	1363
Tele-Fonika Cable	458
Telemark Solutions	4117
Telemetric	2657
Terra Remote Sensing Inc.	2753
Tettex	2960
Therm-A-Guard Div., Universal Thermography, Inc.	3057
Thermodynamics	1855
Thermoforte	2751
Thermoteknix Systems Ltd.	4057
thermOweld Continental Industries Inc.	422
Thomas & Betts Corporation	2829
Thomas & Betts/Meyer Steel Structures	2829
Threaded Fastners	2953
Timco	3554
Trachte, Inc.	525
Trafo and AEPI do Brazil	2149
TransAmerican Power Products, Inc.	1649
Transformer Monitoring Solutions	428
Transformer Protector Corporation/Kuhlman Electric	3641
Tranter Radiator Products Inc.	1918
TRC Companies, Inc.	3748
Tree Tech USA	2027
Trench Limited	2131
Trenwa, Inc.	624
Triangle MicroWorks, Inc.	1648
Triple Crown Products, Inc.	814
Tyco Electronics Corporation/Energy Division	841
Tyndale Company	955
UCA International Users Group	1164
Ulteig Engineers	2855
Underground Devices, Inc.	2315
Underground Systems, Inc.- USI	330
UNIFIN International	911
Union Metal Corporation	415
United Services Group	3415
US Goldenway Inc.	2961
Utilco	518
Utility Automation&Engineering T&D/ Electric Light & Power Magazine/	3052
Utility Products	4127
Utility System Inc.	761
Utility Wind Integration Group	316
UtilX Corporation	1008
V&S Schuler	2853
Vacudyne, Inc,	3421
Vaisala	2018
Valmont Newmark	2041
Vanguard Instruments Company, Inc.	2257
Viat Instruments	2026
Virginia Transformer Corporation	3725
Volani Metais Industria E Comercio Ltda.	2158
Von Corporation, The	2351
W.A. Chester. LLC	2840
W.H. Salisbury & Company	3019
W.I.R.E. Services	347
Wacker Silicones Corporation	910
Washington Group International, Inc.	427
Water-Jel Technologies	421
Waukesha Electric Systems	3031
Weather Decison Technologies, Inc.	4133
WEG Electric Motors Corporation	754
Weidmann Systems International Inc.	1415
Weidmann-ACTI	1415
Weschler Instruments, Div of Hughes Corp.	2743
Weselak Sales Agency	2122
White Rubber Corporation	1915
WIKA Instrument Corporation	3454
Williams Metals and Welding Alloys, Inc.	460
Wilson Bohannan Padlock Company	2815
Wilson Construction, Inc.	621
Wind Turbine & Energy Cables	856
Windsor Communications, Inc.	459
WLT Technologies Inc.	1460
Worley Parsons	665
Xamax Industries, Inc.	3521
XEGsys	1360
Yaskawa Electric America, Inc.	1158
ZAPEL	1652
Zensol Automation Inc.	816
ZIV USA, Inc.	1254

Schedule of Events

May 21-24

Please visit our website at www.ieeet-d.org for updates to the event schedule.

Sunday, May 21

Tutorial Sessions
9:00 am-5:00 pm
Reliability

10:00 pm-12:00 pm
Engineering Ethics for Today's Power Engineer

1:00 pm-5:00 pm
Cyber Security of Control Systems

2:00 pm-4:00 pm
Engineering Ethics for Today's Power Engineer

6:00 pm-9:00 pm
Conference Reception—
Cajuns and Cowboys Ready To Get It On in Dallas at Eddie Deen's

Companion Tours
10:00 am-4:00 pm
Fantastic Fort Worth: A City Tour

10:30 am-3:30 pm
A Trio of Cultural Art

Monday, May 22

8:00 am-10:00 am
Opening Session
Dallas Convention Center

10:00 am-5:00 pm
Exhibition Floors Open

11:30 am-1:00 pm
Luncheon
Exhibition Show Floor

1:00 pm-5:15 pm
Educational Track (ES01-ES02)

10:00 pm-5:00 pm
Poster Sessions
Exhibit Hall A

1:00 pm-5:00 pm
Panel Sessions
Meeting Rooms

2:00 pm-4:00 pm
Super Session 1 (Ballroom C2)
Transmission Investment–It's Time

3:00 pm-5:00 pm
Student Poster Sessions
Exhibit Hall A, Poster Area

3:15 pm-5:15 pm
Educational Track (ES01-ES02)

Companion Tours
10:00 am-4:00 pm
Divine Grapevine–Wine Tasting 101

11:00 pm-4:00 pm
Mystery! Spotlight on the Kennedy Assassination

Tuesday, May 23

8:00 am-10:00 am
Special Interest Group 1
Material Costs

8:00 am-5:00 pm
Educational Tracks (ES03-ES06)

8:00 am-5:00 pm
Technical Panel Sessions

9:00 am-12:00 pm
Super Session 2 (Ballroom 2)
Wind Energy

9:00 am-5:00 pm
Special Short Course
Power Systems Basics for Non-Engineering Professionals

9:00 am-6:00 pm
Poster Sessions
Exhibit Hall A

9:30 am-5:00 pm
Info Session

10:15 am-12:15 pm
Special Interest Session 2
Broadband

10:15 am-12:15 pm
Special Interest Group 5
Iraq Reconstruction

10:00 am-6:00 pm
Exhibition Floor Open

10:15 am-12:15 pm
Educational Track

1:00 pm-4:00 pm
Super Session 3
Reactive Power

1:00 pm-3:00 pm
Poster Sessions
Exhibit Hall A

1:00 pm-5:00 pm
Special Interest Session 3
Blackouts

1:15 pm-3:15 pm
Educational Track

3:30 pm-5:30 pm
Educational Track

4:30 pm-6:00 pm
Networking Reception
Dallas Convention Center Exhibit Halls

Companion Tours
10:00 pm-3:00 pm
Legendary Ladies of Dallas

10:30 am-3:00 pm
A Trio of Cultural Art

Wednesday, May 24

8:00 am-11:00 am
Educational Track

8:00 am-12:00 pm
Technical Panel Sessions

9:00 am-12:00 pm
Super Session 4
Cyber Security

9:00 am-12:00 pm
Special Interest Session 4
Transmission Capacity

9:30 am-3:00 pm
Info Session

9:00 am-3:00 pm
Poster Sessions
Exhibit Hall A

10:00 am-3:00 pm
Exhibition Floor Open

11:30 am-1:00 pm
Collegiate Luncheon

1:00 pm-4:00 pm
Technical Panel Sessions

2:30 pm-4:00 pm
Closing Ceremony and Reception

Companion Tours
9:00 am-2:00 pm
Shopping Tours

Automating the thinking and reducing guesswork about the health of electrical transformers.

By: Jeff Golarz, Product Manager, Serveron Corp.

In a sense, a new era in Dissolved Gas Analysis (DGA) has arrived. And not too soon; as so much of this understanding has been more of an art than a science in the past. With the ongoing and much –reported age-wave retirement, much intimate knowledge of transformers is leaving the utilities. The embedding and systemization of their knowledge into interpretation software programs has been something we have now added to our Dissolved-Gas-Analysis (DGA) transformer monitoring devices.

Automatically-generated and actionable, Dissolved-Gas-Analysis (DGA) diagnostics for transformers.

Paradigm shift: **takes the industry from a detective-corrective mode to a strategic-preventative mode.**

These days, the electric utility world is stepping up its investment in an array of technical developments in systems that have the ability to accurately capture, track and analyze outage information. The impetus is partly explained by the growing movement by commissions to regulate quality through Utility performance.

While useful, this emphasis belongs in the tactical arena of detective-corrective – a kind of closing of the barn door after the proverbial cows have been stolen.

Leading companies have focused their commitment to quality and energy reliability through the development of devices that significantly prevent transformer failures. It is appreciated now, that the average age of transformers in America is about 42 years and are approaching the end of their designed life expectancy. It is not overly dramatic to predict that all of these transformers will eventually fail, and sooner rather than later.

With on-line dissolved-gas monitoring and now, with automatically-generated analysis and interpretation of the monitoring data – there is a clearer way to quickly understand the health of transformers and to take action to prevent failures. One could describe this progress as “strategic-preventative” as opposed to “detective-corrective”.

Fortunately, in this case, doing the right thing and saving lots of money - happen together.

Power transformer failures increasingly result in tank-rupture, fires, extensive damage to other equipment and disastrous consequences including blackouts. The economics for on-line DGA monitoring deliver a compelling business case for utilities world-wide. With automated interpretation of the data, we continue to learn about the contributing factors that affect transformer health and how to detect and act on the information. The combination of automated interpretation tools and the monitoring that generates the underlying data should revolutionize the way utilities manage these critical transformer assets and deliver impressive ROI.

It has taken 2 years to monitor and gather data on the equivalent of 220,000 transformers.

Transformer users would have to carry out manual DGA on 220,000 transformers twice a year to equal the volume of transformer gas data that we gathered and analyzed in the past two years.

Becoming authorities, by virtue of the database we have grown and diagnostic tools employed, has enabled the drawing of correlations and trends between the DGA data and the transformer-events.

Standards and Guidelines; Making sense of them.

There are a number of Standards and Guidelines for diagnostic tools supporting DGA interpretation and these include the North American Standards setting body, the Institute of Electrical and Electronics Engineers (IEEE) who have issued Std C57.104-1991: IEEE Guide for the

Circle **37** on Reader Service Card

	H_2	CO	CO_2	CH_4	C_2H_2	C_2H_4	C_2H_6	O_2	H_2O
Cellulose decomposition		✓	✓						✓
Mineral oil decomposition	✓			✓	✓	✓	✓		
Leaks in oil expansion systems, gaskets, welds . . .			✓					✓	✓
Thermal faults – Cellulose	✓	✓	✓	✓				✓	
Thermal faults in Oil @ 150°C-300°C	✓			✓		trace	✓		
Thermal faults in Oil @ 300°C-700°C	✓			✓	trace	✓	✓		
Thermal faults in Oil @ over 700°C	✓			✓	✓	✓			
Partial Discharge	✓			✓	trace				
Arcing	✓			✓	✓	✓			

Fault Gas Indicators

Interpretation of Gases Generated in Oil-Immersed Transformers" (approved June 27, 1991). IEEE PC57.104 Draft 11d: Draft Guide for the Interpretation of Gases in Oil-Immersed Transformers" (most recent draft is dated April 21, 2004; currently being balloted for approval).

Then there is the International Electro-technical Commission (IEC) – Geneva, Switzerland (IEC 60599-1999: The Interpretation of Gases in Transformer and Other Oil-filled Electrical Equipment in Service), and CIGRE of France.

The table at left represents the common knowledge about fault conditions and the dissolved gases that indicate those conditions. The table above shows dissolved Hydrogen as being common to most faults. The problem with Hydrogen, and our caveat here is, that Hydrogen is not really a diagnostic gas.

H2 is a very light molecule with extremely low solubility in the oil. There is little doubt that H2 due to any type of discharge rises in bubbles due to buoyancy & oil flow, collects in small gas pockets, and ultimately escapes through gaskets, welds & oil preservation system. H2 has little likelihood of showing up (especially at a drain valve) particularly with directed-flow as used by most large power transformers. H2 may have time to dissolve during a day-in/day-out thermal problem but the type of oil preservation system makes a huge difference as to how much is accumulated.

On-line DGA more & more shows such differences. In addition, H2 can be caused by a variety of conditions inside a transformer – rust, moisture in a galvanized pipe fitting (i.e. connected to a drain valve), and sunlight. Almost everything causes H2 in mineral oil. Hydrogen is not a diagnostic gas.

On-Line DGA data populating diagnostic tools delivers useful interpretation power and trending; the insight is in rate of change (ROC), not in snapshots.

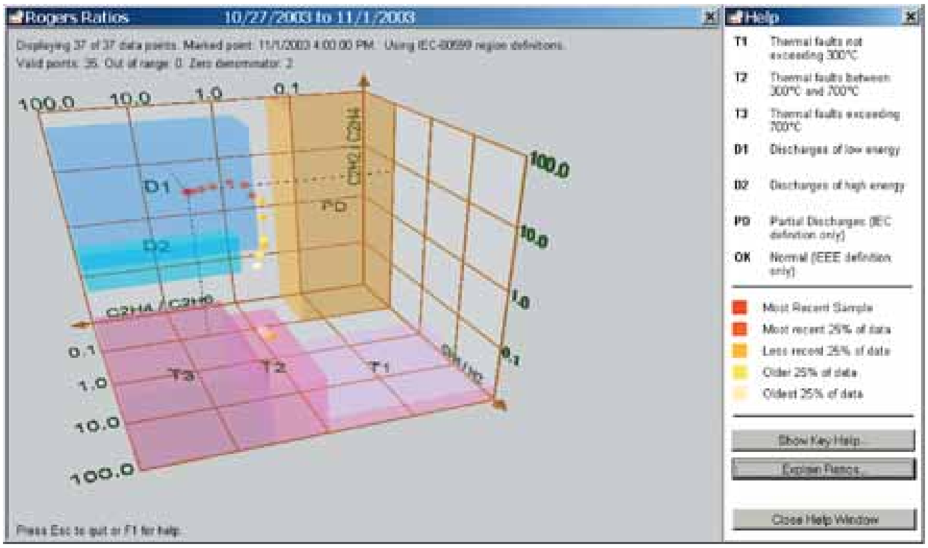
An inherent difficulty for IEEE (& IEC) DGA interpretation guides is that they cover the entire range of transformer sizes, design types, oil quantity, oil preservation systems, operating conditions, maintenance history & age. Just about everything makes a difference.

Therefore, it is the Rate-of-change (ROC) that becomes more important than absolute values.

Results from periodic oil sampling from transformer drain valves are highly variable for many reasons & can be downright misleading. On-line monitoring of all the individual gases is discovering this every day.

The opportunity therefore is on-line diagnostic tools that deliver rates of change not only of individual gases, but of the ratios that provide

Figure 1



enhanced (and actionable) information about the health of the transformers. Therefore, the next evolution is: automation of diagnostics with inputs from on-line DGA – a new capability.

Good examples of models that deliver actionable, automatically-generated interpretations and insights are the Duval triangle and Rogers' ratios. Rogers's ratios are recognized in the IEEE Standards & Guidelines and are equivalent to the "Basic Gas ratios" in the IEC.

Duval's Triangle Model is recognized in the IEC Guidelines and this as been automated also. The CO2 vs. CO ratio is a third useful metric as an indicator of thermal decomposition of cellulose insulation with high potential for detecting emerging problems (IEC 60599-1999).

The relationships of gas concentrations can be displayed in 3-dimensional graphical representations on-line, together with the gas concentration data – to provide a diagnostic of root causes, and where necessary a call-to-action. (See Figure 1 and side bar of Rogers Ratio, to the left.)

Populating diagnostic models with on-line data enables new insights

Duval Triangle (IEC 60599 Appendix, developed by IREQ/Hydro Quebec) combined field service evidence with laboratory experiments published in 1989 followed by enhancements in 2002. This method uses the individual ppm of 3 gases – CH_4, C_2H_4 & C_2H_2 – relative to the total ppm of those three gases, to locate a point

This Three-phase 700 MVA 400 kV GSU transformer was monitored continuously with one-line generated diagnostics including Rogers Ratio analysis. Trending demonstrated increasing Methane (CH_4), Ethane (C_2H_6), Ethylene (C_2H_4) and a sudden increase in Acetylene (C_2H_2) initiating an alarm. The transformer was removed from service within 12 hours.

This problem was clearly a thermal fault evolving to a discharge of low energy.

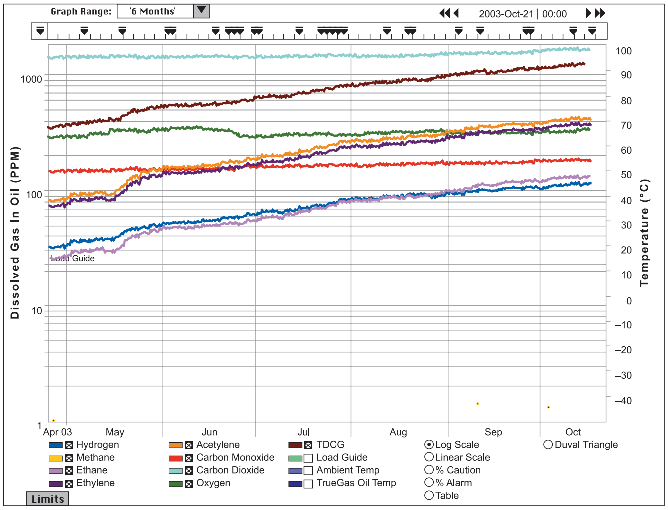
The Transformer was inspected. Intermittent grounding was provided by the fastening bolt causing a transient potential rise and subsequent discharges occurring between the corona ring on the high voltage lead and the main tank ground point.

An on-site repair was performed and the transformer was returned to service.

Figure 2

	GAS	*Partial Discharge*	*Thermal Fault (Oil)*	*Thermal Fault (Oil)*	*Thermal Fault (Oil)*	*Electrical Fault*	*Electrical Fault High Energy (Arcing)*
Duval Triangle (IEC 60599)	CH_4, C_2H_2, C_2H_4	PD	T1 t < 300°C	T2 t = 300-700°C	T3 t >700°C	D1 Low Energy Discharge	D2 High Energy Discharge
Rogers Ratios (IEEE PC57.104-1991)			Low Temp. Thermal < 300°C	Thermal 300-700°C	Thermal > 700°C	Low Energy Discharge	High Energy Discharge
1) Acetylene/Ethylene	C_2H_2/C_2H_4		< 0.01	< 0.10	< 0.20	>1.0	> 0.6 < 3.0
2) Methane/Hydrogen	CH_4/H_2		> 1.0	> 1.0	> 1.0	> 0.1 < 0.5	> 0.1 < 1.0
3) Ethylene/Ethane	C_2H_4/C_2H_6		< 1.0	> 1.0 < 4.0	> 4.0	> 1.0	> 2.0

Figure 3



within the triangle. Sections within the triangle designate: thermal fault < 300 C; thermal fault 300-700 C; thermal fault > 700 C; low-energy discharge; high energy discharge; and partial discharge.

In addition to the automation of the Rogers Ratios model (equivalent to Basic Gas ratios per IEC), we have also automated the Duval model. It is a more recent development that according to experts, delivers a useful and reliable interpretation of transformer health. Figure 2 shows a comparison of the Duval triangle and Rogers Ratio methods.

The take-away from this chart is that as one's experience grows in the category, the greatest value lies not in the absolute values, but in the trending. Trending is the way to catch a problem.

How a multi-million dollar transformer was saved with on-line monitoring and automated diagnostics of the data – a real life example

Figure 3 shows on-line DGA is for a Three-phase 700 MVA 400 kV GSU transformer showing increasing Methane (CH_4), Ethylene (C_2H_4) & Ethane (C_2H_6) and slowly increasing Carbon Monoxide (CO).

Looking at the gases individually, each are in the "normal" PPM range. However, both Duval and Rogers ratios say it's hot (hot metal). Later, (months), individual gases demonstrated that condition.

However on-line, automatically generated diagnostics delivered an earlier, actionable insight. See Figure 4.

The utility was able to manage load, monitor diagnostic ratios, and nurse the unit until repair. The concentration of dots on the Duval triangle indicates close to a T3, but still in T2 range due to load management and monitoring.

It was the combination of DGA monitoring data and the diagnostic tools that provided the insight to a problem that would not have been obvious otherwise.

The cause was a defective brazing (shown in Figure 5), an excellent example of the value of the automation of high-level diagnostic capability – to manage transformer performance and reduce the risk of unplanned failure.

Figure 5

Summary

Reliable, affordable, smart technologies exist today that can manage critical utility assets. Given the criticality of the transformers fleets, it makes sense to begin thinking seriously about wide programs of transformer DGA monitoring with the use of on-line automatically generated diagnostic functionality. It makes good sense and it makes for good governance. ■

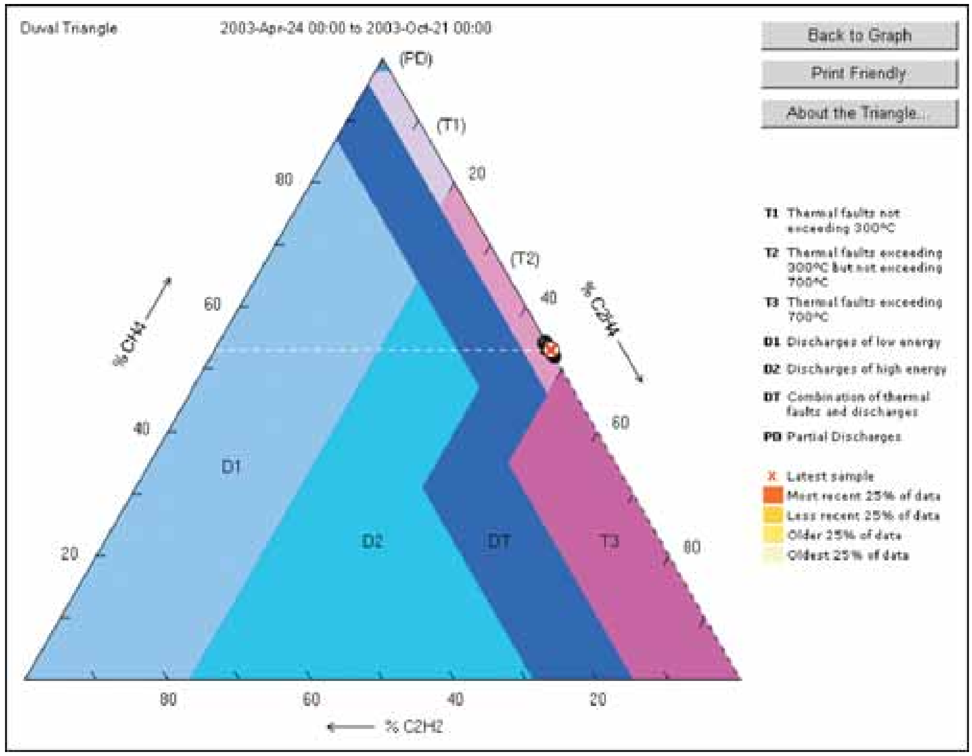


Figure 4 - The Duval Triangle indicates T2 - Thermal Fault - 300 to 700 C.

UNDERVOLTAGE LOAD SHEDDING – PART 1

By: Charles Mozina, Consultant, Beckwith Electric Co., Inc.,
marketing@beckwithelectric.com

I. INTRODUCTION

This article discusses why voltage as well as frequency load shedding may be necessary to prevent major system blackouts. It is the first of two articles on the important subjects of power system voltage collapse and undervoltage load shedding. The first article will discuss the causes of system voltage collapse while the second article will propose schemes to address the problem. The second article (part2) will be in the next issue of T&D. Investigations of recent blackouts [1,3,7] indicate that the root cause of almost all of these major power system disturbances is voltage collapse rather than the underfrequency conditions prevalent in the blackouts of the 1960 and –'70s. This article explores the nature of recent power system blackouts (2003 east coast, 1996 California and others) and explains why voltage collapse is the leading edge indicator of impending power system problems. Part 2 of this article will discusses the design and security issues that need to be addressed in the design of an undervoltage load shedding (UVLS) scheme and why relying on underfrequency load shedding (UFLS) maybe "too little, too late." Part 2 will also address the current level of UVLS on utility systems as well as current NERC (North American Electric Reliability Council) pronouncements on the subject.

II. WHY VOLTAGE COLLAPSE IS THE CAUSE OF RECENT BLACKOUTS

Power systems today are much more susceptible to voltage collapses than they were 35 years ago as we increasingly depend on generation sources that are located remotely from load centers. Generators in eastern Canada and the midwestern U.S. provide large amounts of power to east coast load centers such as New York City. Generators in Washington, Oregon and western Canada provide substantial power to southern California. Two factors promote generation that is remote from load centers:

- The economics of purchasing power from lower-cost remote sources rather than more expensive local generation.
- The public's reluctance/refusal to permit new generating plants to be built in urban high-load areas, causing utilities/IPPs to build these plants remote from these load centers.

These two fundamental changes in operation of the U.S. power grid result in the transmission of power over long distances. This makes the power grid very dependent on the transmission system to deliver power to the load centers. It also results in increased reactive power losses when transmission lines trip.

Another key factor that results in rapid system voltage collapse is the nature of the loads that are being served by utilities. Many of today's loads are single-phase small air conditioning motors. This was not the case 35 years ago when air conditioning was not as prevalent. These small motors are prone to stall when subjected to voltage dips caused by transmission system short circuits. During hot weather, these motors comprise a high percentage of the utility load. The slow tripping of stalled motors and the relatively slow re-acceleration of more robust motors result in low system voltage after a transmission system fault is cleared [2]. The voltage dip and its effect on these motors are exacerbated if the transmission system fault is cleared via a time delay backup relay or is a mullti-phase fault. Such a slow-clearing fault resulted in the voltage collapse that caused a blackout of the city of Memphis in 1987 [3].

Fig. 1 shows an example of voltage recovery for a Phoenix area transmission system fault incident that occurred in July 1995 during hot weather.

Fig. 2 illustrates a basic power system with the remote generators supplying a significant amount of power (Ps) over a considerable distance to the remote load center. The load is comprised of resistive load and motor load. During a voltage dip resistive load current will decrease and help limit the need for local reactive support. Motor loads are essentially constant kVA devices. The lower the voltage, the more current they draw—increasing the need for local reactive

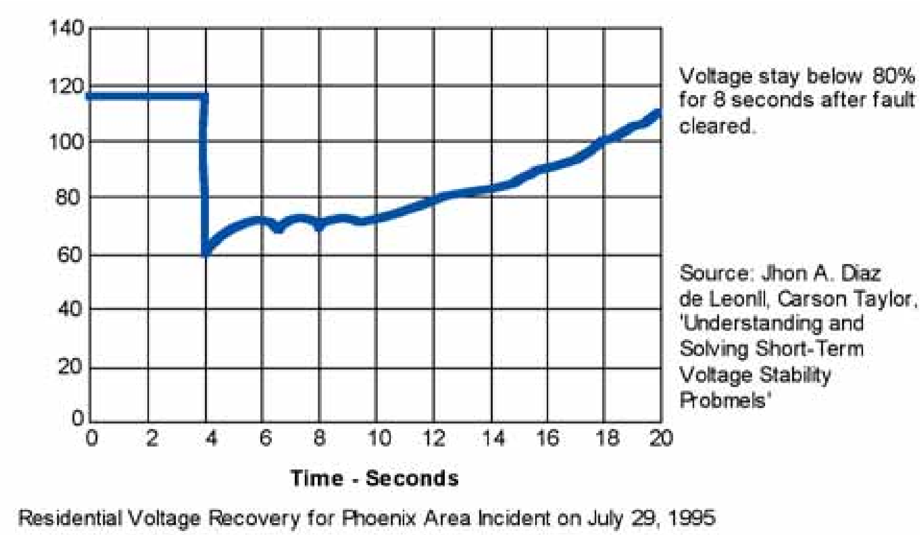


Fig. 1 Example of Delayed Voltage Recovery Resulting from a Transmission Fault

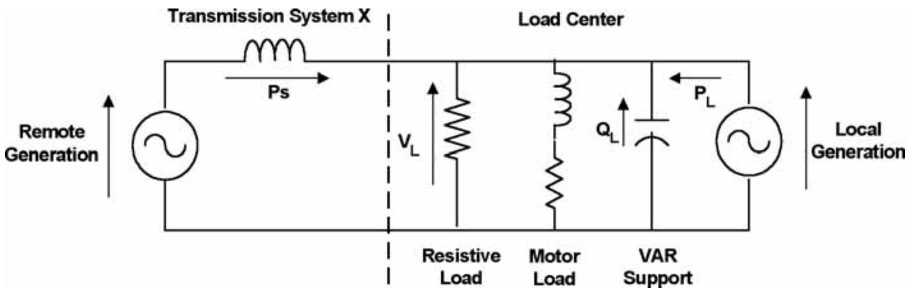


Fig. 2 Basic Power System

(VAr) support. Power systems loads consist of both resistive loads as well as reactive motor loads. During hot weather, however, air conditioning motor loads comprise a large portion of total load, thereby making the system more susceptible to voltage collapse.

Reactive power (VArs) cannot be transmitted very far, especially under heavy load conditions, and so it must be generated close to the point of consumption. This is because the difference in voltage causes VArs to flow and voltages on a power system are only typically +/- 5% of nominal. This small voltage difference will not cause substantial VArs to flow over long distances. Real power (MW) can be transmitted over long distances through the coordinated operation of the interconnected grid whereas reactive power must be generated at, or near, the load center.

Since VArs cannot be transmitted over long distances, the sudden loss of transmission lines results in the immediate need for local reactive power to compensate for the increased losses of transporting the same power over fewer transmission lines. If that reactive support is not available at the load center, the voltage will go down. For these reasons, voltage—rather than frequency—has become the key indicator that the power system is under stress. Utilities recognize that frequency can remain normal as voltage sags to a low level prior to a complete system collapse and are implementing UVLS schemes to complement their existing underfrequency load shedding programs.

II. TYPES OF POWER SYSTEM INSTABILITIES DURING SYSTEM DISTURBANCES

A. Basics – Voltage vs. Frequency Stability

In a power system, frequency is a measure of the balance of MW generation and MW load. When MW generation and MW load are exactly in balance, the frequency is at the normal level of 60 Hz. When load exceeds generation, the frequency goes down. The rate of decline depends on the inertia of the generators within the system. Under normal conditions, there are slight changes of frequency when load suddenly increases or generation trips off-line which results in a slight (hundreds of a hertz) reduction in frequency until the aggregate generation in the system can be increased to meet the new load condition. If there is a large negative unbalance between MW load and MW generation, the frequency is reduced. UFLS schemes on the utility system are designed to restore the balance by shedding load.

Voltage is a measure of the balance of MVAr load and MVAr capability within a power system. If that reactive support is not available, the voltage goes down. Reactive power system support can only come from two sources: shunt capacitors and generators/synchronous condensers. Shunt capacitors are a double-edged sword. They do provide reactive support, but they also generate fewer VArs as the voltage dips. The VAr output of a capacitor bank is reduced by the square of the voltage. Shunt capacitor banks cannot quickly adjust the level of reactive power.

Generation at the load center can provide a dynamic source of reactive power. As the voltage goes down, the generator can quickly provide increased reactive support within its capability limits. Unlike shunt capacitors, the amount of reactive support does not drop as system voltage goes down. The amount of reactive power is controlled by the generator automatic voltage regulator (AVR). It is essential that the AVR control be properly set and the generator protection system allow the generator to contribute the maximum reactive power to support the system without exceeding the generator's capability.

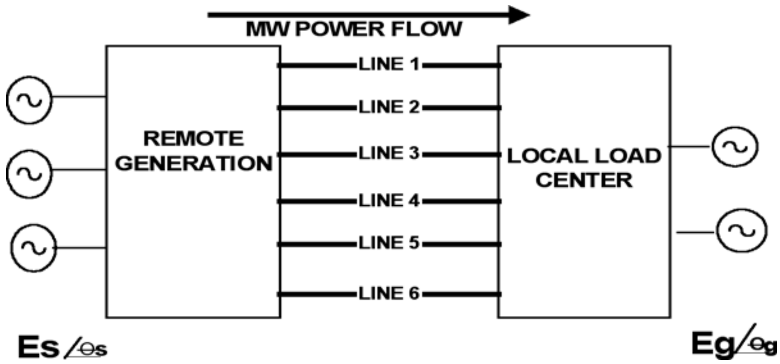


Fig. 3 Power System with Remote Generation

B. Voltage Instability

Fig. 3 illustrates a simplified power system with a remote generator supplying a substantial portion of the load at the load center through six transmission lines. Es is the voltage at the remote generator buses and Eg is the voltage at the load center buses. As lines between the remote generators and the load center trip the MW power flows over fewer lines resulting in increased VAr losses.

Fig. 4 illustrates how voltage decays as lines trip. This type of P-V analysis (real power relative to voltage) is an analysis tool, used by utility system planners, to determine the real power transfer capability across a transmission interface to supply local load. These curves are also called nose curves by system planning engineers. Starting from a base-case system (all lines in-service), computer-generated load flow cases are run with increasing power transfers while monitoring voltages at critical buses. When power transfers reach a high enough level, a stable voltage cannot be sustained and the system voltage collapses. On a P-V curve (as in Fig. 4), this point is called the "nose" of the curve. The shape of the nose of the curve depends on the nature of the load at the load center. High levels of motor load combined with capacitor bank support of load center voltage tend to make the voltage drop very rapidly for a small increase of power at the nose of the curve. The set of P-V curves illustrates that for baseline conditions shown in curve A, the voltage remains relatively steady (changing along the vertical axis) as local load increases. System conditions are secure and stable to the left of point A1. After a contingency occurs, such as a transmission circuit tripping, the new condition is represented by curve B, with lower voltages (relative to curve A). This is because the power being transmitted from the remote generators now follows through five, rather than six, transmission lines. The system must be operated to stay well inside the load level for the nose of curve B. If the B contingency occurs, then the next worst contingency must be considered. The system operators must increase local generation (Eg) to reduce the power being transmitted for the remote generators to reduce losses, as well as increase voltage at the load center to within the safe zone, to avoid going over the nose of curve C.

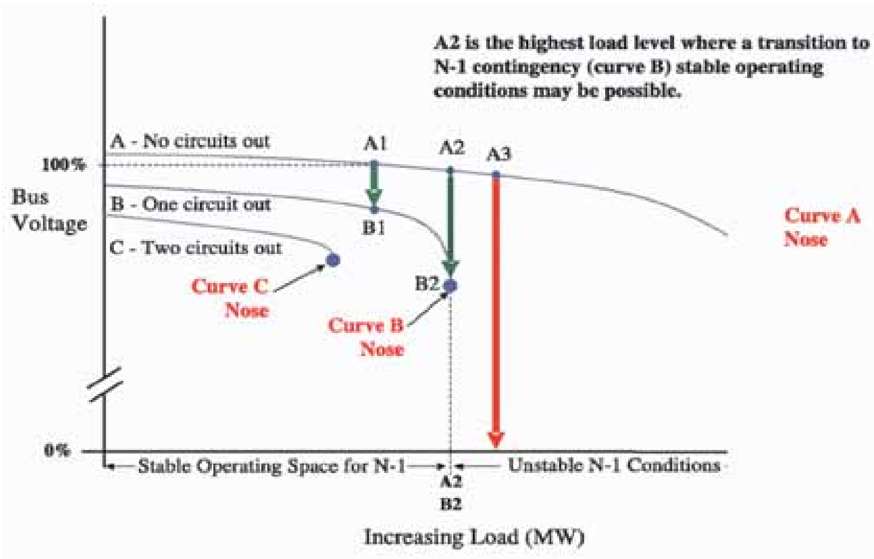


Fig. 4 Real Power (MW) vs. Voltage (P-V) Curve -- Nose Curve

In the case of the 2003 East Coast blackout [4], three key transmission lines were lost in rapid succession due to faults caused by tree contacts. The voltage at the load center was reduced before the system operators could take effective corrective action. Effective operator action was inhibited by the lack of data from key transmission system substations due to a computer problem at the system operating center. The loss of the fourth line due to load entering a third zone relay characteristic was the final tripping that triggered the blackout.

In the case described above, voltage decay was relatively slow and there was time for system operator intervention to address the voltage decay problem. There have been cases where the voltage decayed so rapidly that operator action was not possible. These cases involve slow-clearing multi-phase transmission system faults that occur during heat storm conditions when the utility load is primarily made up of air conditioning motors. Due to the extended length of the voltage dip resulting from the slow-clearing transmission system fault, motors in the area began to stall and draw large amounts of reactive power after the fault is cleared. The rapid change in load power factor results in low system voltage as shown in Fig.1. Since there is little reserve of reactive power during peak load periods, the area voltage collapses. Such an event occurred in western Tennessee (Memphis) and resulted in an outage of 1100 MW of load. The entire event took less than 15 seconds [5].

C. Phase Angle Instability

When the voltage phase angle between remote generators and local generators ($\theta g - \theta s$ in Fig. 3) becomes too large, phase angle instability can occur. In many cases, this event happens in conjunction with the voltage collapse scenario described above. There are two types of phase angle instability.

Fig. 5 illustrates how steady-state instability occurs. The ability to transfer real (MW) power is described by the power transfer equation and is plotted graphically. From the power transfer equation in Fig. 5, it can be seen that the maximum power (Pmax) that can be transmitted is when $\theta g - \theta s$ = 90°, i.e. sin 90° = 1. When the voltage phase angle between local and remote generation increases beyond 90°, the power that can be transmitted is reduced and the system becomes unstable and usually splits apart into islands. If enough lines are tripped between the load center and the remote generation supplying the load center, the reactance (X) between these two sources increases, thereby reducing the maximum power (Pmax) which can be transferred. The power angle curve in Fig. 5 illustrates this reduction as line 1 trips the height of the power angle curve and maximum power transfer is reduced because the reactance (X) between the two systems has increased. When line 2 trips, the height of the power angle curve is reduced further to where the power being transferred cannot be maintained and the system goes unstable.

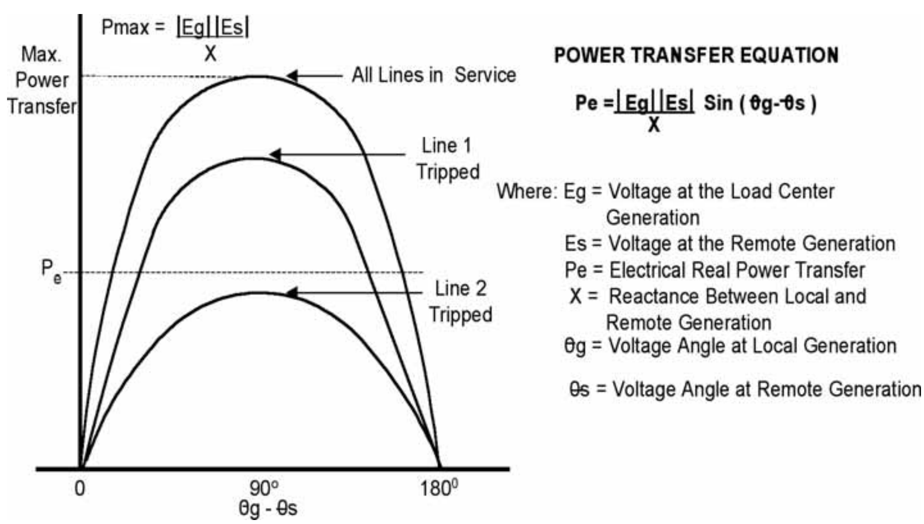


Fig.5 Power Angle Analysis - Steady-state Instability

1) ***Steady-State Instability:*** Steady-state instability occurs when there are too few transmission lines to transport power from the generating source to the local load center. Loss of transmission lines into the load center can result in voltage collapse as described above, but it can also result in steady-state phase angle instability.

At this point, the power system is in deep trouble. During unstable conditions, the power system breaks up into islands. If there is more load than generation within an island, frequency and voltage go down. If there is more generation than load within an island, frequency and voltage generally go up. Voltage collapse and steady-state instability occur together as transmission line

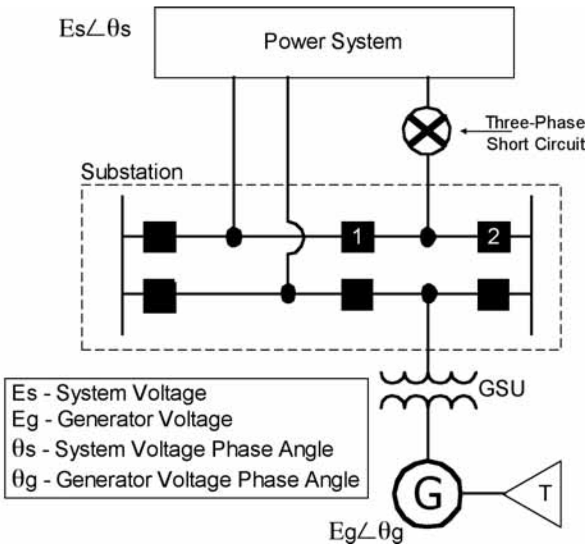


Fig.6 Typical Large Power Plant One-Line Diagram

tripping increases the reactance between the load center and remote generation. Generally, the voltage drop at the load center is the leading indicator that the system is in trouble with low frequency occurring only after the system breaks up into islands. Analyses of major blackouts indicate that voltage is more of a leading edge indicator of power system impending collapse. Waiting for the frequency reduction may be waiting too long to shed load to save the system.

2) ***Transient Instability:*** Voltage phase angle instability can also occur due to slow-clearing transmission system faults. This type of instability is called transient instability. Transient instability occurs when a fault on the transmission system near the generating plant is not cleared rapidly enough to avoid a prolonged unbalance between mechanical and electrical output of the generator. A fault-induced transient instability has not been the cause of any major system blackout in recent years. However, generators need to be protected from damage that can result when transmission system protection is slow to operate.

Relay engineers design transmission system protection to operate faster than a generator can be driven out of synchronism, but failures of protection systems have occurred that resulted in slow-clearing transmission system faults. It is generally accepted [2] that loss-of-synchronism protection at the generator is necessary to avoid machine damage. The larger the generator, the shorter is the time to drive the machine unstable for a system fault. Fig. 6 illustrates a typical breaker-and-a-half power plant substation with a generator and a short circuit on a transmission line near the substation. If the short circuit is three-phase, very little real power (MW) will flow from the generator to the power system until the fault is cleared. The high fault current experienced during the short circuit is primarily reactive or VAr current. From the power transfer equation (Fig. 5), it can be seen that when Eg drops to almost zero, almost no real power can be transferred to the system. The generator AVR senses the reduced generator terminal voltage and increases the field current to attempt to increase the generator voltage during the fault. The AVR control goes into field-forcing mode where field current is briefly increased beyond steady-state field circuit thermal limits.

During the short circuit, the mechanical turbine power (P_M) of the generator remains unchanged. The resulting unbalance between mechanical (P_M) and electrical power (Pe) manifests itself with the generator accelerating, increasing its voltage phase angle with respect to the system phase angle as illustrated in the power angle plot in Fig. 7.

The speed with which the generator accelerates depends on its inertia. The larger the generator, the faster it will accelerate. If the transmission system fault is not cleared quickly enough, the generator phase angle will advance so that it will be driven out of synchronism with the power system.

Computer transient stability studies can be used to establish this critical switching angle and time. The equal area criteria can also be applied to estimate the critical switching angle (θ_C). When area A1 = A2 in Fig. 7, the generator is just at the point of losing synchronism with the power system. Note that after opening breakers 1 and 2 to clear the fault, the resulting post fault power transfer is reduced because of the increase in reactance (X) between the generator and the power system. This is due to the loss of the faulted transmission line. In the absence of detailed studies, many users establish the maximum instability angle at 120°. Because of the dynamic nature of the generator to recover during fault conditions, the 120° angle is larger than the 90° instability point for steady-state instability conditions. The time that the fault can be left on the system that corresponds to the critical switching angle is called the “critical switching time.” If the fault is left on longer than that time, the generator will lose synchronism by “slipping a pole.” For this condition, the generator must be tripped to avoid

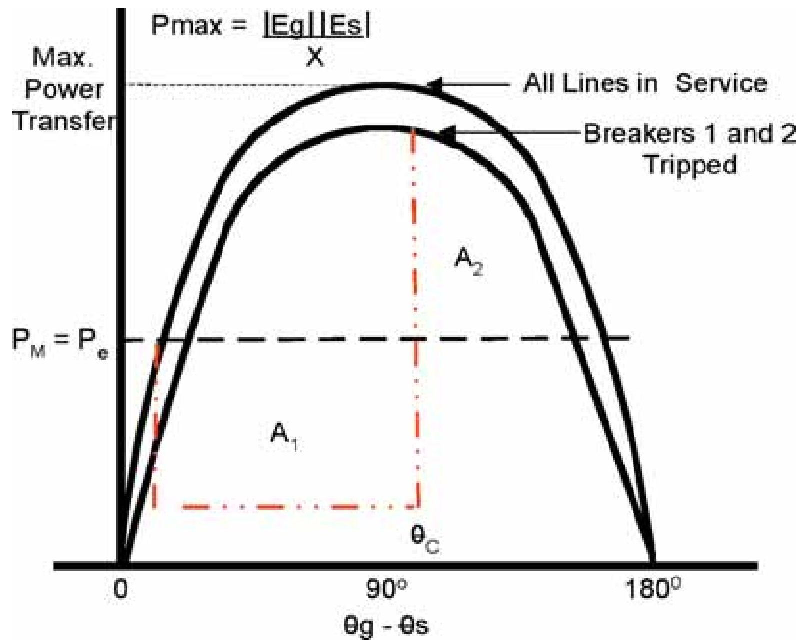


Fig. 7 Power Angle Analysis – Transient Instability

shaft torque damage. Out-of-step protection, which is also called loss-of-synchronism protection (relay function 78), is typically applied on large generators to trip the machine—thereby protecting it from shaft torque damage and avoiding a system cascading event.

D. Dynamic Instability

Dynamic instability occurs when a fast-acting generator AVR control amplifies, rather than damps, some small low frequency oscillations that can occur in a power system. This problem has been most often associated with the western region of the U.S. It can, however, occur anywhere the load is remote from the generation. While fast excitation systems are important to improve transient stability as discussed above, a fast-responding excitation system can also contribute a significant amount of negative damping. This reduces the natural damping torque of the system, causing undamped megawatt oscillations after a disturbance such as a system fault. This type of event can occur if the generator is interconnected to a weak system and loads are far from the generating plant. As discussed, the operation of today's power grid makes this scenario much more likely in many regions of the U.S.

Small signal stability is defined as the ability of the power system to remain stable in the presence of small disturbances most often caused by remote faults. If sufficient damping torque does not exist, the result can be generator rotor angle oscillations of increasing amplitude. When these megawatt oscillations grow, the generator can eventually be driven unstable, lose synchronism and slip a pole. To address this problem, a Power System Stabilizer (PSS) is utilized in conjunction with the generator AVR to provide positive damping when megawatt oscillations occur.

The next issue of T&D will address the current status of undervoltage load shedding programs and the design criteria for a secure undervoltage load shedding program.

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About the Authors

Chuck Mozina is a consultant for Beckwith Electric. He is an active 25-year member of the IEEE Power System Relay Committee (PSRC) and is the past chairman of the Rotating Machinery Subcommittee. He is active in the IEEE IAS I&CPS, PCIC and PPIC committees, which address industrial system protection. He is a former U.S. representative to the CIGRE Study Committee 34 on System Protection and has chaired a CIGRE working group on generator protection. He also chaired the IEEE task force that produced the tutorial "The Protection of Synchronous Generators," which won the PSRC's 1997 Outstanding Working Group Award. Chuck is the 1993 recipient of the Power System Relay Committee's Career Service Award and he recently received the 2002 IAS I&CPS Ralph Lee Prize Paper Award. His papers have been republished in the IAS Industrial Applications Magazine.

Chuck has a Bachelor of Science in Electrical Engineering from Purdue University and is a graduate of the eight-month GE Power System Engineering Course. He has authored a number of papers and magazine articles on protective relaying. He has over 25 years of experience as a protection engineer at Centerior Energy, a major investor-owned utility in Cleveland, Ohio where he was the manager of the system protection section. In that capacity, he was responsible for the electrical protection of the company's generating plants as well as the transmission and distribution system that served over 1.2 million customers. For ten years, he was employed by Beckwith Electric, a manufacture of protective relays, as Application Manager for Protection Products. He is also a former instructor in the Graduate School of Electrical Engineering at Cleveland State University as well as a registered Professional Engineer in Ohio.

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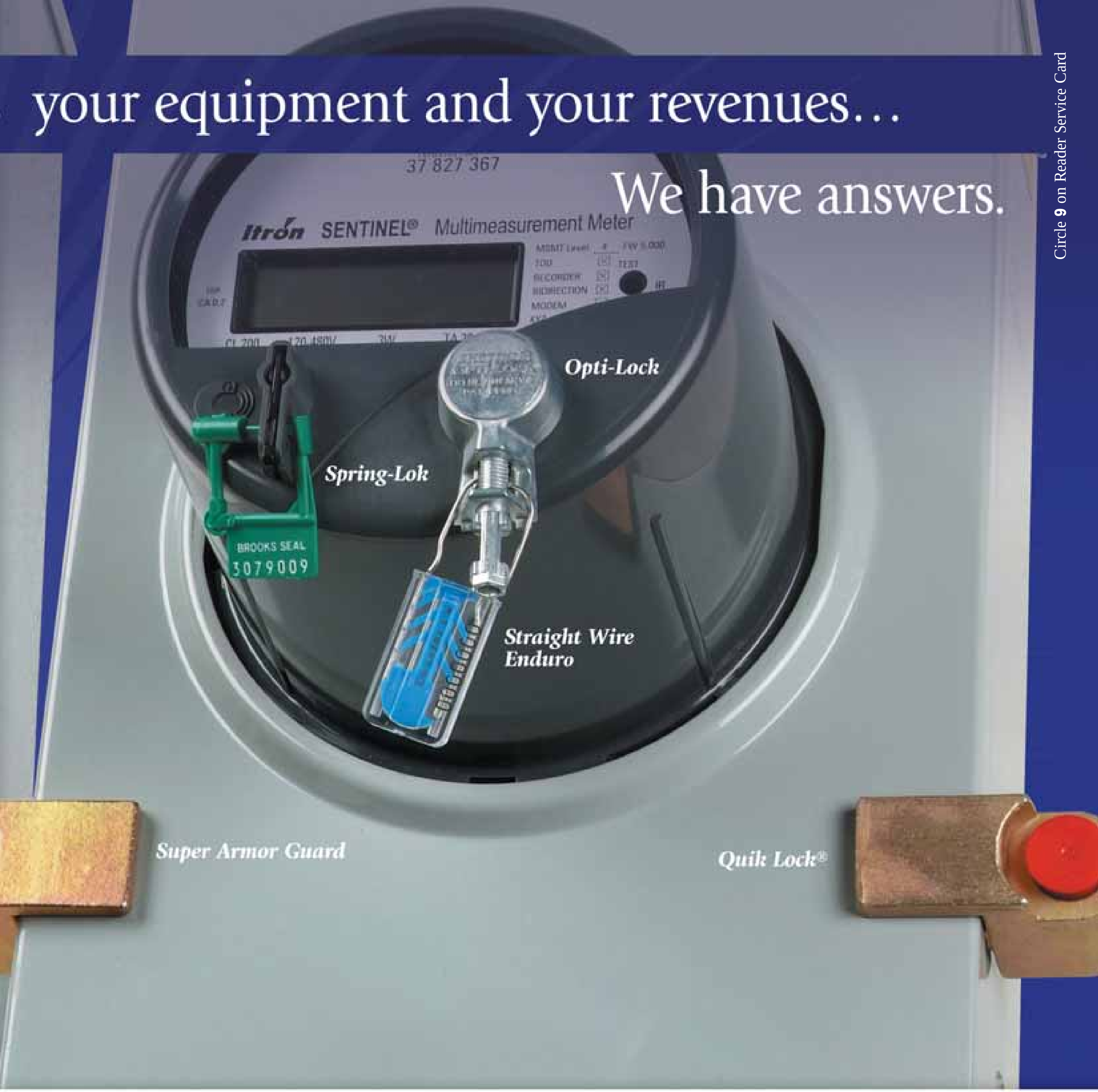
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Maintaining Reliability of Supply and Price Competitiveness in North America: Hydro-Québec's Strategies

The recent substantial rise in oil prices has an impact on medium and long term supplies of electricity. In the open and competitive North American energy market, electricity prices have also been subject to upward pressure. What are Hydro-Québec's strategies to maintain availability of supply and competitive rates for its more than three million customers? André Boulanger is an engineer, trained at Université Laval (Québec City, 1976) and studied business management at the University of Western Ontario (London, 1995). He started his career at Bell Canada and worked as project manager and consultant for various firms. In 1983, Mr. Boulanger joined Gaz Métropolitain where he held a variety of management positions for over 20 years. He joined Hydro-Québec in 2003 as President of Hydro-Québec Distribution. The division manages assets totaling $10 billion (Can.), employs 7,500 people, operates a grid of some 107,000 km of distribution lines and operates 24 thermal power plants.

Tuesday, June 13, 2006

8:00 a.m. - Registration and Conference opens
8:30 a.m. to 10:00 a.m. - Keynote Breakfast
10:30 a.m. to 12:00 p.m. - Sessions
12:00 p.m. to 1:00 p.m. - Lunch
1:00 p.m. to 3:45 p.m. - Sessions
4:00 p.m. to 5:00 p.m. - Networking Reception

Wednesday, June 14, 2006

8:00 a.m. - Registration opens
8:30 a.m. to 12:00 p.m. - Sessions
12:00 p.m. to 1:00 p.m. - Lunch is available on show floor
1:00 p.m. to 2:30 p.m. - "Practically Speaking"
2:30 p.m. to 4:00 p.m. - Sessions
4:00 p.m. to 5:00 p.m. - Networking Reception
7:30 p.m. - Optional Dinner at Le Cabaret du Roy in Old Montréal

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10:30 a.m. to 12:00 p.m. - Sessions
12:00 p.m. to 12:45 p.m. - Lunch is available on show floor
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1:30 p.m. to 2:15 p.m. - Sessions

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Fiber Optic Temperature Sensors Applied to a Various Array of Transformers

By: Sharon Walsh, Product Line Manager, Energy/Oil and Gas Industry, FISO Technologies Inc.

Reliability in the electric power industry formerly came from the ability to plan power systems with significant redundancy. Increasing competition and limited resources are forcing utilities to reduce capital spending and find cost-effective resources and solutions to optimize their new equipment and apply appropriate preventative maintenance of their system.

It is only fair for utilities to make the most efficient use of their transformers using various approaches. The most common approach includes a desire and need for increased loading. In some cases, it has been shown through an overall life cycle cost analysis that it is more profitable to overload existing transformers and accept the penalty of increased loss of life, than to relieve the loading by installing larger or more transformers. Increased loading appears to be a commonly used mean but it can lead to serious problems if no efficient method is applied to accurately and safely monitor the necessary parameters. The most important parameter in a transformer's life cycle relies on the certainty of the winding's hot spot(s) value through the transformer's lifetime.

Fiber optic sensors are an excellent and increasingly cost effective way to access capacity and gather information on the unit's health through direct temperature measurement of the hot spot. Fiber optic temperature sensors were previously dedicated for use in large power transformers basically due to the expenditure of the fiber optic systems opposed to the cost of the transformer itself. The use of a direct method allows accurate measurement of the transformers' hot spot for an increased knowledge of operational condition assessment; load planning, asset management and end of life determination.

Considering their design particularities and the impact of temperature on aging of the insulation and life expectancy, the need for direct temperature measurement of small, medium and large power and distribution transformers is much needed.

Hot Spots and their known consequences

For a long time, transformer load was applied conservatively and it was common to add or replace a transformer when it surpassed the 60%-70% load levels. Such load levels did indeed preserve the transformer's health over longer periods of time as demonstrated with transformers which operated or have been in operation for over 40 years. Nowadays, it is more common to run the transformer closer to its maximum nameplate capacity, planning less redundancy and causing more frequent overloading of the transformer. This situation has a direct impact on the winding hot spot temperature

According to ANSI/IEEE C57.12.80-1978, the continuous rating of a transformer is "The maximum constant load that can be carried continuously without exceeding established temperature-rise limitations under prescribed conditions". There is a wide array of temperature limitations such as ambient temperature, top oil temperature, core lamination temperature, average winding temperature rise and the maximum winding temperature rise.

One of the most important parameters in determining the balance between lifetime and load within the liquid filled transformer is the "hot spot" temperature or the maximum winding temperature rise. This represents the temperature of the hottest part within the transformer, typically residing in the windings. Should the hot spot exceeds given limits, the rate of deterioration of the solid and liquid insulation system in the transformer will accelerate rapidly.

Temperature has a major influence on the aging of the insulation and on the transformer's lifetime. An accurate prediction of the hot spot in the winding is consequently very important for both manufacturers and end-users considering the hot spot is responsible for the degradation of the transformer oil and paper insulation.

Since the temperature distribution is not uniform within a transformer, the insulation paper will ordinarily undergo the greatest deterioration when exposed to high temperatures. When insulation paper loses its properties, it weakens the transformer both dielectrically and mechanically. In addition, higher winding hot spot temperatures not only weaken the winding insulation material but it can ultimately result in the formation of gas bubbles that facilitate the dielectric breakdown of the transformer's oil. Needless to say that, a similar situation is undesirable and as it is in most cases irreversible.

Transformers

Manufacturers offer various transformer types and designs according to the utility's requirements and needs. Some transformer designs are more at risk considering their complexity and special characteristics. Fibre optics monitoring system provides added value to these specific types of transformers.

- **Autotransformers;** these transformers tend to have a higher leakage flux when compared to a typical transformer.
- **Converter transformers;** these transformers show fundamental differences in the flux pattern.
- **Axial split designs;** Transformers such as generator step-up (GSU's) designed with two low voltage windings build one on top of the other. Cooling and flux distribution is not as straightforward as with typical transformers and therefore require close monitoring.
- **Phase shifters**
- **Zigzag**
- **Stepdown transformers**
- **Repaired or upgraded transformers;** specially if a know weakness of the design have been find out

There are other aspects to be considered when deciding to choose direct fiber optic monitoring versus mechanical or electronic simulated methods. A transformer presenting special characteristics is often subjected to natural but yet undesirable phenomena.

- **High impedance;** causing more leakage flux, worsening the hot spot
- **High harmonics;** knowing that the magnetic leakage flux is proportional to the square of the frequency. For example, the third harmonics (180Hz) generates 9 times more flux than the fundamental (60Hz), contributing to the winding Eddy losses.

Lastly, it is important to consider in which condition the transformer will operate regardless of its design and/or size.

- **Load situation**

- **Overload situation**

- **Critical transformer**

- **Replacement/Backup transformer**

- **Physical location;** According to According to the IEEE C57.12.90 – 1999 (Revision of IEEE C57.12.90-1993) IEEE Standard Test Code for Liquid-Immersed Distribution, Power, and Regulating Transformers an altitude correction must be applied to the temperature rises.When a transformer tested at an altitude of less than 1000 m (3300 ft) is to be operated at an altitude above 1000 m.

The Use of Fiber Optics Inside Small, Medium and Distribution Transformers

The use of fiber optics has mainly been applied to large power transformers due to their complex design and the benefits gained from direct temperature monitoring are easily paid back. This same technology is now applicable to small, medium and distribution transformers considering it offers an excellent and increasingly cost-effective solution for direct, accurate and real time hot spot temperature measurement.

The distribution transformers tight insulation design and ongoing utilization along with less cooling justify the significant needs for direct, accurate and real time overall temperature of smaller power and distribution transformers. In small distribution transformers the temperature rise is significantly higher due to the number of turns and layers in the windings, compared to larger transformers which have less turns and more cooling ducts. Outdoor ambient conditions may have an effect on the loading capacity of the distribution transformers according to the IEC 60076-7.

Unlike the large power transformers there is no predetermined top oil and hot temperature for the distribution transformers under short term emergency loading but is however known that here may be gas bubble formation should the hot spot exceed 140 C°. Fiber optics is the most accurate and suitable monitoring method to validate hot spot temperatures within the windings.

Small and medium transformers may also necessitate direct fiber optic temperature monitoring depending on operating conditions as mentioned previously.

Benefits of direct temperature monitoring using fiber optics

There are technical benefits associated to the use of fiber optics for hot spot monitoring of transformers.

- Provides assistance in transformer design and rating verification;
- Safely maximizes loading and overloading;
- Reduces overall physical stress on winding;
- Prevents premature failure;
- Prevents outages and catastrophic failures.

There are also economical benefits such as better knowledge of operational condition assessment, load planning, and asset management. End of life determination becomes easier to plan and consequently to manage considering there are less costly interventions.

- Reduces inspection and maintenance costs;
- Reduces failure-related repair or replacement costs;
- Improves real-time transformer loading capability;
- Defers upgrade capital costs due to load growth;
- Defers replacement capital costs due to equipment age or condition.

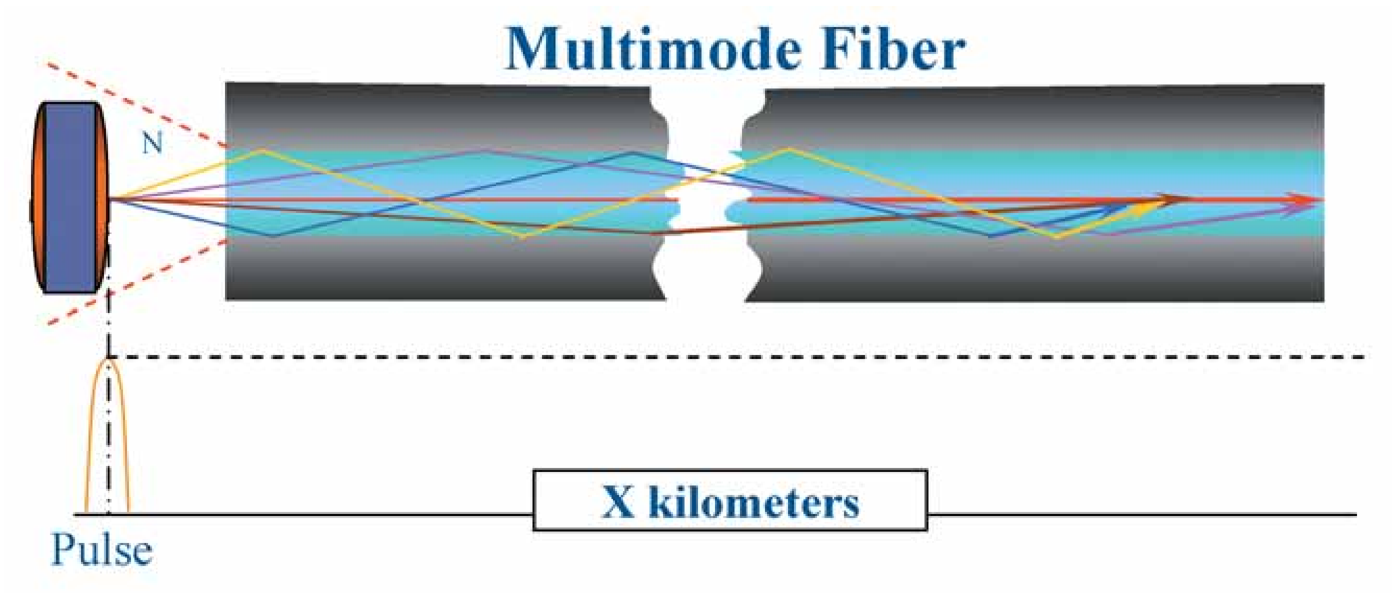

Figure 1: Fiber, Light and GaAs

Available Technologies

Point sensing fiber optic sensors are the most commonly used for hot spot monitoring. There are a few technologies available such as GaAs (Gallium Arsenide) Absorption and Fluoroptics.

Fiber optic temperature sensors for direct winding temperature measurement in transformers are based on light absorption and transmission of light by a semiconductor (GaAs). The effects of temperature variations using this semiconductor are well know and predictable. A tiny GaAs semiconductor is bonded to one end of a well polished optical fiber using high temperature adhesive.

The sensor is comprised of a multimode optical fiber packaged in two layers of durable bright yellow and royal blue PTFE TeflonTM, which is terminated with a semiconductor (GaAs) crystal and a dielectric reflective coating at the fiber tip. The sensors robust and all-dielectric construction offers excellent thermal (-30 to 225° C largely covers the expected range), high tolerance to multiple connections and bending and chemical resistance to oil and kerosene vapour along with a high tolerance to vibration and installation stresses.

Light that is transmitted through the semiconductor impinges on the dielectric reflective coating at the end of the sensor, and is then reflected back to the spectrum analyzer via the optical coupler. This optical signal is converted into an electrical signal using a CCD (charge-coupled device), and processing electronics then evaluate the cutoff wavelength of absorption within the multi-wavelength spectrum. Consequently, analysis of the optical spectrum by the spectrum analyzer is equivalent to knowing the semiconductor's temperature within the transformer windings. The algorithm/calculations does not depend on light intensity but its spectral response. Since this communication is performed optically, using highly dielectric components within the transformer itself, the reliability of the signal is never compromised by the electric fields.

Although there are several fiber optic direct winding temperature measurement solutions, product reliability, company knowledge, cost-effectiveness and efficient support should be considered. Well established and knowledgeable companies constantly thrive to offer the best solution possible by innovating and offering instrument grade solution adapted for the electric industry.

Up to this day, they are a certain number of available products on the market. Non-

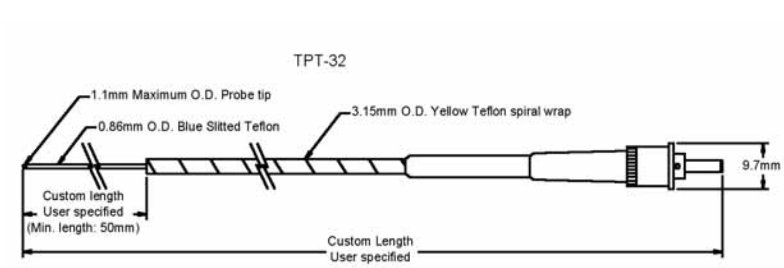

Figure 2: Fiber Optic Temperature Sensor Design

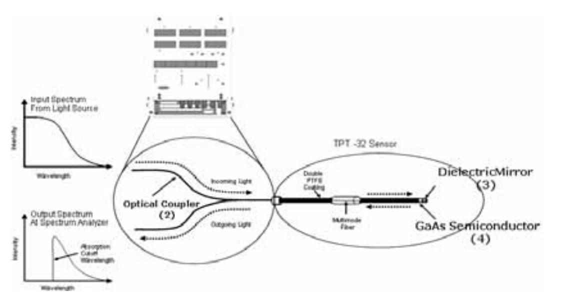

Figure 2- Operating Principle

experienced players and OEM type products may not be the most suitable choice as they may not be as reliable and well adapted for the specificity of the application. Their knowledge and experience may be very limited and they are not in a position to offer a successful and proven history regarding the long term reliability of their products. It is important to note that OEM type products' environmental and shielding (EMI, RF) capabilities may be questioned unless integrated within a thoroughly certified third party unit. ISO 9001 compliant suppliers as well as product certification demonstrates and ensures the company's genuineness and stringent quality standards in design and manufacturing of the product.

Conclusion

Initial investment, design complexity and the utilities' monitoring capabilities does indeed play an important role in deciding to opt for the optical method.

There is a real benefit associated to on-line monitoring. According to the article "Profitability Assessment of Transformer On-Line Monitoring and Periodic Monitoring" published by Jacques Aubin, André Bourgault and Claude Rajotte, it is estimated, that the failure resolution can amount to approximately $13,000 USD/year for equipment which do not use monitoring compared to $ 6000 USD/year when using monitoring. If you compare the cost associated for the purchase, installation and annual support based on a 20 year expected life of monitoring system, which grossly amounts to $1025 USD/year, there is an annual benefit from failure resolution cost of approximately $ 6000 USD/year.

For a fraction of the overall transformer cost, utilities can integrate a fiber optic "insurance policy. Choosing to do so does not only provide you with long term thermal information but it also provides you economic benefits such as reduced inspection, maintenance costs, failure and improved real-time transformer loading capability confidently.

About the Author

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Ms. Walsh earned her Bachelor Degree in Consumer Affairs with a minor in Marketing from Laval University in Quebec, Canada.

Highlights from the North American Study of Substation Automation and Integration Activities and Plans

By: Charles W. Newton, Newton-Evans Research Company, Inc., Ellicott City, Maryland

North American electric power utilities account for more than one quarter of the world total for spending related to substation automation and integration (A&I) programs. Newton-Evans Research estimates the current annual global spending for substation automation and integration programs at about $550-600 million, with an overall potential market size of nearly $40 billion. The year-end 2005 study has found that 76% of the North American utility respondents indicated having a substation automation and integration strategy in place.

Ranking of Importance of "Potential Obstacles" to Implementing Substation Automation for New and Existing (Retrofit) Substations:

New Substations - The lack of appropriate communications technology (substation to substation) and the fact of not enough skilled internal staff were the leading "potential obstacles" to substation A&I program investments. Lack of funding was especially important for investor-owned utilities and for Canadian utilities.

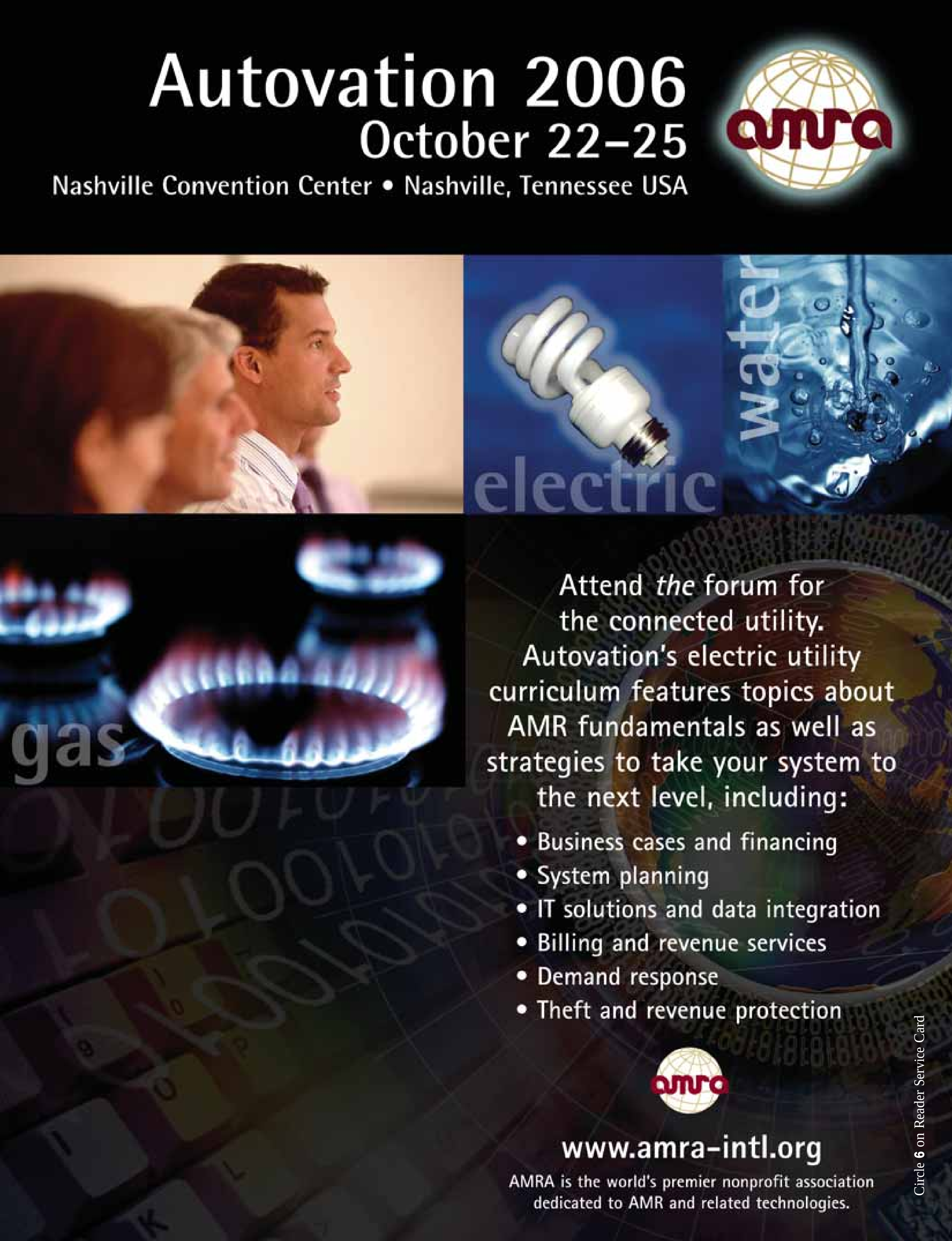
Existing (Retrofit) Substations - For retrofit substations, the biggest obstacles reported were lack of funding and benefits/costs perceptions. This finding was reported by IOUs, public power utilities and Canadian utilities. Cooperatives were more likely to be concerned with the benefits, but concerns over substation communications were strong as well.

Spending Estimates for New and Retrofit Substation Automation Programs between 2005-2007:

North American utilities reported significantly increased plans for spending on substation automation-related programs from earlier studies. The total of about $155 million is more than double the amounts reported as available for substation automation spending in the 2002 study. Again this year, IOUs in the US and Canada dominated spending plans, but the other utility groups also plan to spend in the millions of dollars ranges. Plans for spending on retrofit substations for the next five years (192 million dollars) outpaced plans for similar spending on new substations over the same five year period (177 million dollars).

Approach to Obtaining Substation Automation Systems and Equipment:

Forty-six percent of the North American utilities indicated that they bought from "Best in Class" suppliers of individual substation equipment for A&I programs. Nine percent indicated purchases only from larger suppliers active in the market. Over one third (34%) reported buying equipment only, and then integrating the equipment internally. Thirteen others reported use of consultants to develop a comprehensive substation A&I plan. Only three reported purchasing directly from substation system integrators.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Current and Planned Use of Protocols Within the Substation:

Just about three quarters of the North American utility respondents cited current use of DNP3.0 (Serial) and nearly one quarter indicated use of DNP 3.0 (LAN). None of the current international standard IEC protocols was cited by any utilities as being in use by August 2005. There were some plans to use IEC 61850 by 2007 (six percent). Modbus and Modbus Plus remain strong, with 37% citing some use of Modbus (serial) and 22% citing use of Modbus Plus.

Current and Planned Use of Protocols from the Substation to An External Host:

One half of the group was using DNP 3.0 and 22% had moved on to DNP 3.0 LAN. There was only minimal use of any other protocol listed, while several write-ins of older legacy proprietary protocols were still popular. Among these were: ACS, CDC, Conitel, L&G/Telegyr, QUICS and Tejas/Valment/Metso protocols. Current users of DNP serial were by and large planning to migrate to the LAN version of DNP. Officials indicated that for the most part (81%) they were using standard versions of protocols, while 18% were using both tailored and standard versions of communications protocols. Fewer than ten percent of the North American utility substation officials indicated that they were encrypting data transmissions (or protocols) used in substation communications.

Current and Planned Choices of Physical Links and Media from the Substation to External Hosts/Networks:

Over one half of the respondents indicated at least some use of fiber or synchronous optical network linkages. Forty-three percent continue to rely on leased lines, while 40% cited use of MAS radio, and 38% were using microwave. Importantly, IOUs are the subgroup most likely to use at least some telephony in their comms media mix. IOUs were also planning to use some frame relay and microwave, more than other subgroups.

Number of Ethernet Ports Available in a Typical Substation:

Thirty-six officials indicated that no Ethernet ports were typically available in their T&D substations. Of those who did indicate having such ports available, the nominal midpoint was 8 ports, with a few having either 24 or 48 ports. Eighty percent of the respondents to this question indicated that their substation Ethernet ports were in fact secured. Two thirds of those who had indicated secure ports stated that they were secured via port security methods, while 19 said "other" methods were being used. Other methods included: NMS, authentication, OP addressing, firewalls, and passwords.

Number of Simultaneous Wireless Connections Allowed in the Substation:

Forty-four of 74 respondents indicated that they allow "no" simultaneous wireless connections in their substations. Fifteen said that one or two were permitted. The need for simultaneity seems to be more apparent when the substation data is required by two or more entities (utilities, utility-ISO/RTO, utility engineering/ utility operations).

Use of Modems in the Substation Communications Schema:

Twenty-two percent of the 97 respondents indicated no use of modems. This was especially likely among public power utilities. IOUs were very likely to be using at least some modems. Most of the modem users were using at least some hardwired modems (97%), while 12% were also using some cellular modems and seven percent were using other forms of wireless modems.

Security of Remote Connections (Such as Modems, Wireless Connections):

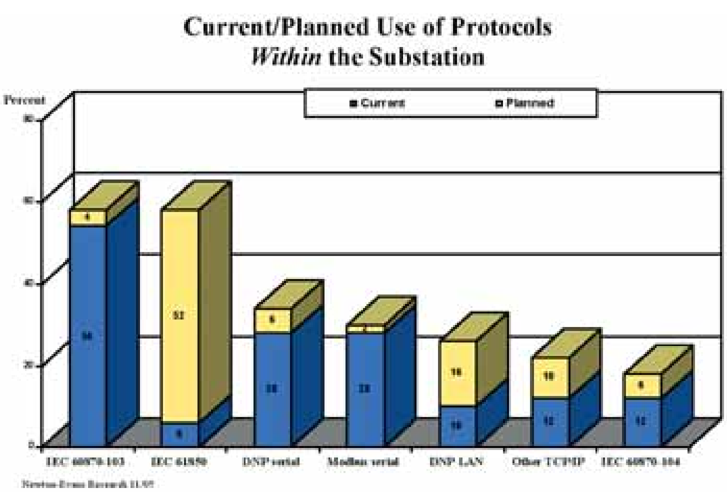
Fifty-nine percent of the 96 respondents to this question indicated that their remote connections were secured, while 41% admitted using unsecured connections. Only 37 of the 57 users who cited having secure connections indicated having ALL of their connections secured. Only 19% of the 96 responding utility officials indicated that they encrypted or otherwise protected communications in remote connections. Eighty-one percent admitted to using unsecured communications in their remote connections. Only one third of the utilities were making use of routable paths to their end devices. Most (77%) of those utilities using routable paths were also monitoring the pathing.

Current and Planned Choice of Communications Architecture within and to the Substation:

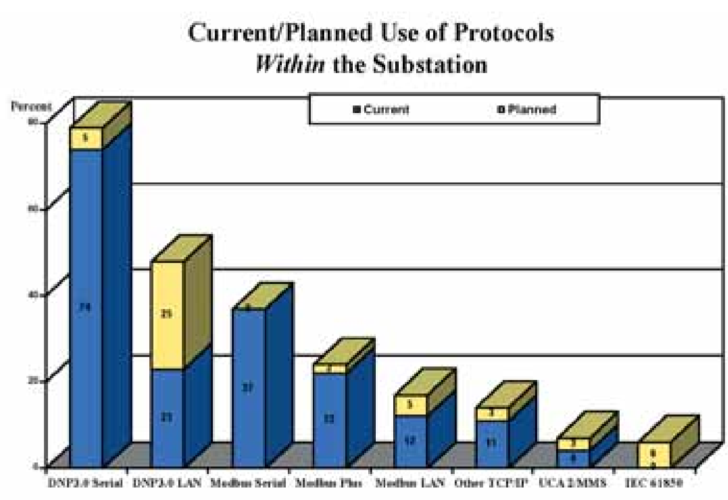
Within the Substation - By and large, serial links continue to be widely used in North American substations in mid-2005, regardless of the type of utility operating the substation. LAN usage is found in substations operated by 42% of the respondent sites. There was minimal use of and minimal plans for VSATs and WANs in the substations of North America, based on the study findings.

To the Substation - Current communications architecture to and from the substation was still likely to be serial links, but the use of WANs has increased from earlier Newton-Evans studies. Plans call for even more use of WAN architecture over the next few years, followed at a distance by increased uses of LANs.

Comparative Communications Protocol Use and Plans: International v. North American Utilities



International Utilities



North American Utilities

Current and Planned Handling of Primary Substation Information Processing Tasks "Inside the Fence":

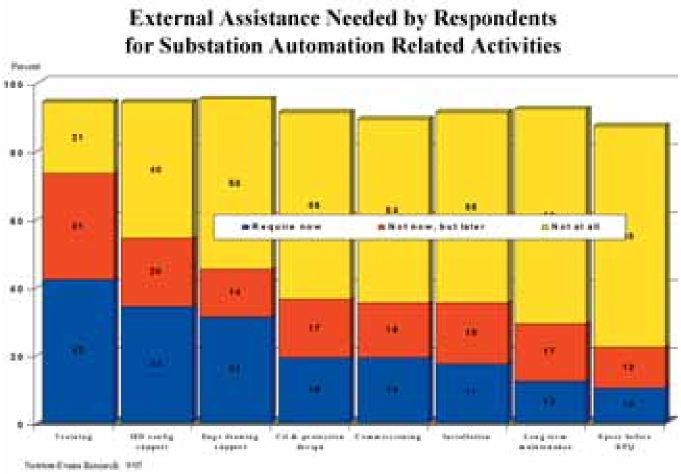
By late 2005, smart RTUs were prevalent in North American substations, with dumb RTUs next. PLC use was acknowledged by 26% of the group. PC use in substations had reached 20%. Dumb RTUs were still in use at least in some substations among 53% of Canadian utilities and one half of the responding electric cooperatives.

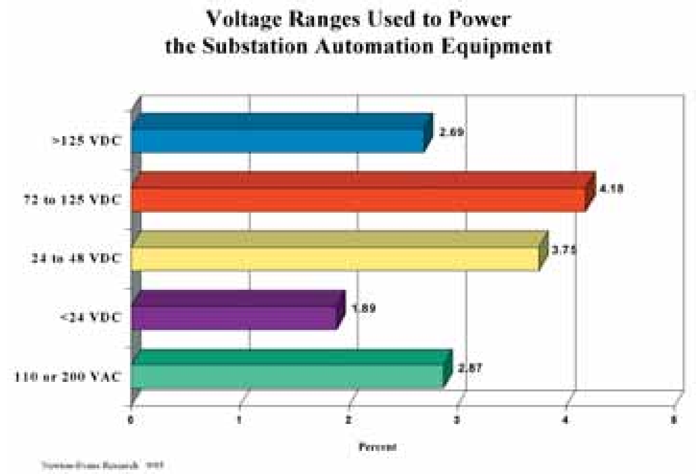
Current and Planned Connectivity of Substations to Other Utility Systems:

Across the industry, utility SCADA or EMS systems led the way with 93% indicating links from substations back to these systems. Smart feeder devices were mentioned by 41% of the group, and protection engineering by 36%. Plans centered around establishing some degree of linkage capability from the substation to the corporate WAN, to GIS systems and to trouble call, protection engineering and maintenance, but all of these plans were below 20% mention rates.

External Assistance Needed for Various Substation Automation Activities:

This question was asked to gain insight into what types of services could be provided by third-party firms, whether they are specialist service firms, or equipment or systems suppliers, into the substation marketplace. By mid-2005, utilities were indicating a need for training assistance (42%), for IED configuration support (34%) and for engineering drawing support (31%). These rates exceed the demand seen in earlier Newton-Evans studies.





Level of Current and Planned Automation Indicated for Transmission and Distribution Substations:

The respondents included 81 transmission utilities and 95 utilities with distribution substation assets. Together, these utilities accounted for about 35% of T&D substations in North America. Respondents were requested to indicate whether their transmission and distribution substations were not at all automated, or whether they had one of four stages of automation. These four stages were identified as:

Stage 1 - IED implementation; substation has IEDs installed - no integration

Stage 2 - IED integration; installed IEDs are integrated, utilizing 2-way communications capability and NO substation LAN

Stage 3 - IED integration; installed IEDs are integrated, utilizing 2-way communications capability and/or substation LAN

Stage 4 - Applications are run at the substation level to automate various substation functions.

In this study, 7,031 substations were classified by respondents as transmission voltage substations. Another 18,938 units were classified as distribution voltage substations. There were plans in place to construct 223 new transmission voltage substations over the 2005-2007 periods, and an additional 725 new distribution class substations were also planned. The Newton-Evans estimate of total North American utility operated T&D substations is some 64000 units, with non-utility operated substations hovering in the 6,500-8,000 unit range.

Specific Equipment Types in Use and Planned for Use in Conjunction with Substation Automation Programs:

Transmission Substations - Seventy-five utility officials took the time to indicate which of 15 specific equipment types were or were planned to be part of their utility's transmission substation-wide automation programs. RTUs, digital relays, redundant protection schemes and digital fault recorders were all indicated by more than one half of the respondents as component parts of their utility substation automation programs.

Distribution Voltage Substations - Ninety-two officials provided information on the equipment types being used or planned for use in conjunction with distribution substation automation programs. In distribution substations, RTUs, digital relays and LTC transformers were indicated as the most widely used components in automation and integration programs.

Voltage Ranges Used to Power Substation Automation Equipment:

Respondents were requested to indicate the most used voltage ranges to power substation automation equipment in the substations operated by the utilities. Range choices were: 110 or 200 VAC, <24 VDC, 24 to 48 VDC, 72 to 125 VDC, and >125 VDC.

Based on the North American utility responses, the most frequently used voltage ranges used to power T&D substation automation equipment were: 72-125 VDC followed by 24-48 VDC.

Current and Planned Use of Substation Security Measures:

Seven optional responses were listed in this question on substation security methods and practices. Utilities were asked to indicate whether they were using or had plans to use any of the following: encryption of RTU communications, password protection for IEDs, video camera surveillance, improved intrusion detection, secure facilities, eye/fingerprint identification, and limited accessibility to substation-related keys.

Three security measures stand out from the group as having been implemented by mid-2005. These included two physical measures and one cyber measure. First, limited accessibility to substation-related keys; secondly, secure substation facilities (locked building and enclosures); and thirdly, password protection for access to intelligent electronic devices. Plans for adding additional security by 2007 include: improved intrusion detection, deployment of camera surveillance and encryption of RTU communications.

Additional Observations Gleaned from the Study:

- The years 2002-2004 were slow growth - or no growth - years in most categories of intelligent electronic equipment sales related to the modern, increasingly digital, electric power substation. Few retrofit programs were undertaken except for the most critical of substations.

- Increasingly, it is becoming more difficult to separate substation product classifications as manufacturers tout their platforms as "multifunctional" and the product positioning of many electronic devices now cuts across multiple product classifications.

- Newton-Evans further estimates that only about 12% of utility operated substations have been fully automated and integrated by year end 2005. Most of these are in fact newly or recently constructed substations.

- Most substation equipment manufacturers (mid size and smaller companies) and integrators surveyed in the second half of 2005 have indicated some moderate-to-good growth market conditions within their utility sales sectors, resulting in sales that are as much as 5% to 15% higher than 2003 or 2004 sales levels.

- Economic growth has continued in many electricity dependent sectors. In turn, this spurs demand for increased electric power, and increasingly reliable power. This results in internal planning for infrastructure and automation programs.

- There remains some concern in the industry about the dearth of skilled engineering resources due to retirements and layoffs. This may further impact the ability of technology supplier companies to engage utilities for other than short-term requirements. However, third party engineering and integration service firms are now making significant strides in winning substation automation-related business from planning to design to construction.

- If distributed generation activities continue to increase across the world, there is some positive benefit that will occur for the substation automation, integration and retrofit business, as utilities become more involved with DG efforts.

- In summary, retrofit substations will be upgraded as warranted, based on load growth, criticality to customers, and development of DG programs. New substations will increasingly be designed and constructed as integrated and automated remote assets for the utility.

- Protocol use and plans among North American electric power utilities continue to differ from the trends among utilities in the international communities. North American utilities continue to strongly support DNP 3, and will likely migrate to a LAN version of this protocol. See the comparative charts at the end of the release.

- International utilities tend to use IEC protocols. Currently, the 60870-5-103 protocol is popular, especially in Europe, while migration to IEC 61850 is underway in Europe, the Middle East and Africa, and among some of the largest utilities elsewhere. Nonetheless, Latin American and Asian Pacific utilities report strong use of Modbus and Asia-Pacific utilities tend to align themselves more with DNP 3 at the present time. ■

HV CAPACITORS RESPOND TO MARKET DEMANDS WITH IMPROVED PRODUCTION PROCESSES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HV capacitors are key components in circuit breakers and capacitive voltage transformers, used in the transport and distribution of electrical energy in electric utility grids and other high-voltage installations worldwide.

There is a steadily increasing need for energy which is increasing the requirements for transmission and distribution, and a trend towards higher voltages. This means that the requirements for HV capacitor producers are getting tougher, particularly in terms of increasing reliability and cutting production times.

This article describes how Maxwell Technologies, which has around 65% of the worldwide market share for HV capacitors, is responding to these tougher requirements by implementing improvements at its manufacturing facility in Switzerland.

HV CAPACITOR APPLICATIONS

Around 80% of Maxwell's HV capacitors are used in high-voltage circuit breakers for transmission and distribution applications. Dead tank breakers are mostly used in North America, live tank (AIS) breakers in Europe, and GIS breakers around the world. The other 20% are in HV applications that are related to transmission and distribution, for example in laboratory applications.

In live tank switchgear circuit breakers, grading capacitors are used to allow the high voltage to be distributed uniformly in the interrupting chambers. In dead tank breakers, coupling capacitors increase the breaking power of the switchgear.

GIS breakers, which also use grading capacitors, are very compact, mostly used in cities where there is no space to install the external breakers. They are also used for tough environments with extreme temperature.

Very high precision is required for laboratory, testing or calibration equipment, and high-quality high voltage capacitors are required for these applications.

The most important capability of a breaker is its ability to handle high voltage and current, for example 550kv and 40kA. Approximately 60% of the electric utility grid employs circuit breakers rated at an interrupting short-circuit current of 40kA, with most of the balance rated at 63kA. By adding a single coupling capacitor to the circuit breaker, upgrading it from 40kA to 63kA, the circuit receives substantially increased protection. HV capacitors are also used in some systems rated up to 80kA in specialized applications where there is very high power generation, such as in areas of high industrial density.

Maxwell's revenue from HV capacitors is roughly split evenly between the three main markets: Americas (North and South), Europe and Asia. Infrastructure projects in China and other developing countries have been driving strong demand for some time, and there is also now increasing replacement and upgrading activity in the more mature European and North American markets.

TRENDS TO HIGHER VOLTAGE LEVELS

In the US, Europe and China, the most common transportation voltage level is 550kV. 800kV is also used in US, Canada, Korea and is tending to be applied in India and China. This is primarily due to the longer distances that power is transmitted over, requiring higher voltages to minimize transmission losses.

With losses related to the inverse square of voltage, the savings due to higher voltages can be substantial. The resistance of cables is fairly fixed, so increasing the voltage is the main way that transmission losses can be reduced. Also, by increasing the voltage and hence reducing current for a given power, a thinner and lighter cable can be used to carry the lower current.

For example, in China, there tends to be fewer, larger power plants with higher capacity, rather than smaller power plants every 100km or so. The Three Gorges power plant, for instance, supplies power over a huge area.

Worldwide energy demand is forecast to increase strongly – the US government's Energy information Administration (EIA) has forecast the demand for electricity generation will nearly double between 2002 and 2025, from 14,275 billion kilowatt hours to 26,018 billion kilowatt hours (Source : EIA International Energy Outlook, July 2005, http://www.eia.doe.gov/oiaf/ieo/world.html). Other commentators have predicted this doubling will happen as quickly as 2016.

While the installed base of infrastructure will increase, particularly in developing markets, it will not double, supporting the need for higher voltages to increase capacity.

At the higher voltages, reliability and a proven track record become even more important factors in selecting HV capacitors, with operating lifetimes measured in decades not years.

IMPROVING THE PRODUCTION PROCESS

To respond to these changes in the HV capacitor market, and in particular to improve quality and reliability, there has been a need for improvements in the production process.

The main steps to build a high voltage capacitor are as follows, listed in the order that the steps are followed:

- windings
- stack of windings
- assembly
- tightness test
- drying
- impregnation
- electrical test

The basic capacitor electrodes consist of aluminum foil and a dielectric. Maxwell's capacitors have a dielectric that is paper, synthetic film, or a combination of both. A paper/polypropylene dielectric has been found to perform significantly better than previous paper dielectrics, with lower dielectric losses and a more stable capacitance/temperature relationship.

Capacitor units, made on a robotic production line from reels of aluminum foil and dielectric strips, are flattened and then welded to other units to build up a capacitor stack. Once the required stack is built, it is assembled into a casing.

This article focuses on the next three steps in the process: tightness test, drying and impregnation. It describes the changes made in the new process, the improvements achieved, and the benefits for customers.

MOTIVATION

In identifying the need for improvements, it was realized that by automating these process steps a linear flowing manufacturing process could be designed with time and cost optimized.

The objectives were set as follows: firstly, a 20% reduction in lead time, with a reduction of the process throughput time by a factor of 5. The fabrication lot was also to be reduced to the most economical quantity.

The number of processes was targeted for a reduction of 50%, and the production area reduced by 50%.

Perhaps most importantly for customers, targets were set to increase of the product quality and reliability. Finally, a requirement was set to reduce waste with oil to comply with the ISO 14000 certification

The project cost budget was set at $1 million US. Initially, the first price estimation was higher at $1.5 million US. After optimizing the processes, the project was able to be completed within the initial cost target.

The timescale for realizing the project was set at six months, and it was essential that the new installation should not create any delay in deliveries of the HV capacitors. These two targets were also met.

IMPLEMENTATION

Several cycles have been tested and several connection systems have been developed so that the drying time of the capacitor stack (after it has been placed inside the insulator housing) has been optimized without affecting the dryness of the active part before impregnation. Previously, many capacitors were dried together in a large drying chamber. The process has been changed so that fewer capacitors are dried in smaller drying chambers, while the number of chambers has been increased to maintain the same overall capacity.

The new system means that each drying and impregnation cycle now takes only two or three days, instead of 2 to 3 weeks as it did previously. Also, by using independent modular units, different technologies can be impregnated in the same time, which allows optimal fabrication lots and number of fabrication units to be defined, therefore maximizing the number of cycles per week and achieving better flexibility.

The assembly of the complete capacitors is done with "dry" parts. Full drying and impregnation is performed on the assembled unit. With this new process the throughput time has been dramatically reduced, because there is no contamination from humidity.

Previously, the tightness test that was made at the end of the process detected any problems very late after the assembling. With the new process, the tightness test is made directly after the assembly and the test time has been reduced from 72 hours to 5 minutes with a completely new test concept. As a result, if a disassembly is required for corrections, it can be made very quickly without creating any delay of deliveries.

Some of the ideas incorporated have been very simple, but still effective. For example, the porcelain insulators are now left in the packaging they are received in until the final electrical test stage. This means that the manual handling of the heavy insulators has been substantially reduced, which has cut the risk of damages. This has also helped reduce the fabrication area required, and also minimized packaging waste.

RESULTS

Manufacturing throughput time has been cut from 5 weeks to 1.5 weeks, while the lead time has been reduced from between 16 and 20 weeks, to only 12 weeks.

The fabrication lot has been reduced from 144 pieces to 6 pieces, and the number of core processes halved from 6 to 3. The new process also means that the production and storage area required have both been halved.

In terms of quality, the reject rate has been reduced by a factor of 10, from 0.5% to 0.05%.

There have also been improvements in quality. Comparing measurements between products manufactured with old and new processes, in the case of high stress loads the break down time of the capacitors could be increased from 500 hours to 700 hours.

Additional tightness tests with intentional leaks have also shown that the new system could detect the leakage on the first pass, where the previous system could not. This means that the first pass yield after the tightness test has been improved from 97% to over 99%.

Inventory is reduced, and with less handwork and clean working stations there has been a reduction in production costs, as well as an increase in staff motivation which has resulted in better productivity.

BENEFITS TO CUSTOMERS

Most importantly, what does this mean for customers?

Firstly, delivery time has been reduced from 16 weeks to 12 weeks. The process is now also more flexible, enabling the impregnation in parallel of different technologies without increasing the lead time.

The production capacity has been increased through the flexibility of modular units. Additional process units can be installed very quickly and easily to increase the production capacity if required.

Then, the reliability of HV capacitors has been improved with the new process. One factor is that the active part is now impregnated without any contact with the humidity in air. With the reduction in manual handling, the risk of damage is reduced – in fact; there have been zero porcelain breaks during handling in the first year of operation of the new process. By investing in smaller, module units for the drying/impregnation cycle, there is now also no risk of big quantities of defect capacitors due to a single problem in this cycle. www.maxwell.com ■

About the Authors

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Alain Riedo joined Maxwell Technologies SA, formerly Montena Components, as Director of Sales in 1988, and was appointed General Manager in 1994. He has overall responsibility for Maxwell's global high voltage capacitor and equipment businesses and oversees the company's ultracapacitor business in Europe.

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Etienne Savary joined Maxwell Technologies SA, formerly Montena Components SA resp. CONDIS SA, as design engineer in 1986, was appointed Quality Manager in 1990 and Business Unit Manager in 1996. He has now responsibility for research and development for CONDIS high voltage capacitor by Maxwell Technologies SA.

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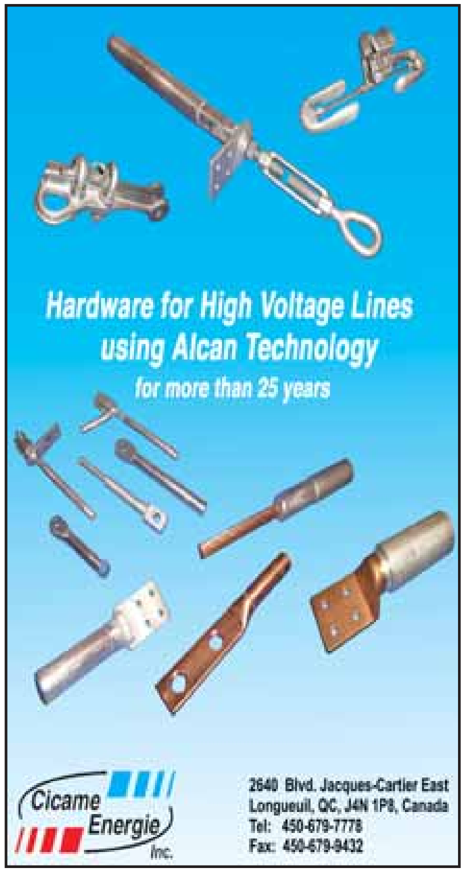

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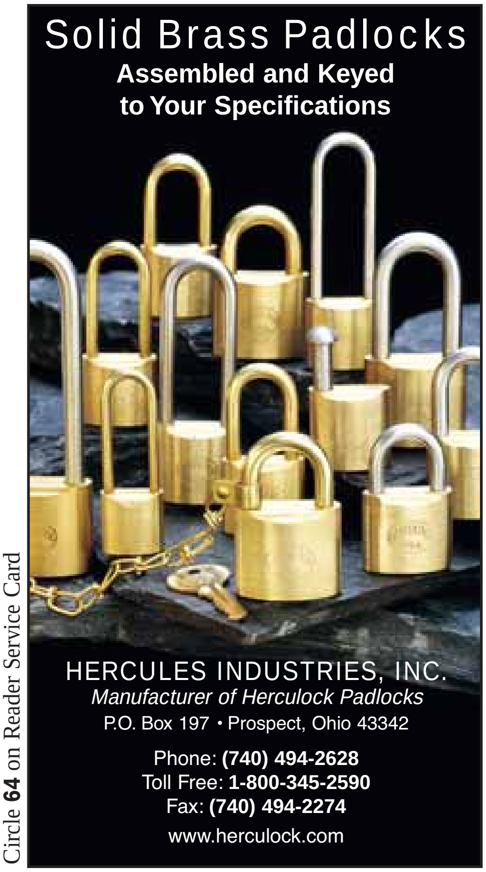

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