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Electric Energy T&D MAGAZINE

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In this Issue

The world of transmission and distribution returns to Chicago. What better venue for a world-class event!


The next generation of transformer oils is already here

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Electric Energy T&D MAGAZINE

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Power transformers are one of the most dangerous electrical equipments because of the large quantity of oil they contain which is in direct contact with high voltage elements.

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It's hard to beat a pair of Dickies® jeans. With great fit and styling, they are among the best-selling jeans in America.
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ASAT Solutions Inc. – Introducing the DAP*mini™* as the Ideal Companion to GE D20 RTUs

Calgary, Alberta, Canada – ASAT Solutions Inc. introduced its latest product, *DAPmini™*, at the DistribuTECH 2008 Conference and Exhibition in Tampa, Florida.

DAPmini™ is the latest addition to ASAT's Digital Automation Platform (DAP) product family. It addresses the increasing information needs of utility customers while leveraging existing automation infrastructure.

With a form factor that fits into a D20 chassis, *DAPmini™* was developed for upgrading the popular GE D20 RTU with minimized effort, hardware and software changes, risks and costs, making Ethernet communication and HMI the integral features of D20 RTUs. *DAPmini™* enables utility users to further utilize the existing D20 assets, and migrate the existing infrastructure to be part of the future Smart Grid.

The GE D20 RTU has been the most robust, reliable and popular RTU for utility SCADA application over the last two decades. However, many users are facing one or more of the following challenges:

- The D20 RTUs are still running well but users need more processing power, memory and functionalities to meet their growing needs.
- A complete replacement of D20 RTUs is not a practical option in near term
- There is a need
  - for a practical migration path from your D20 RTUs to the next-generation substation automation platform for enabling Smart Grid
  - to add Ethernet capability to the D20 RTUs
  - for an ease-of-use HMI for visualization of substation information
  - for IP-based remote maintenance and diagnostic capability
  - to integrate Ethernet and serial based IEDs in the substations
  - to address access security of the D20 RTUs
  - for a D20 upgrade solution with minimized hardware and software change, minimized re-commissioning and outage duration, and minimized risks and costs.

DAPmini™ provides a plug-and-play solution and a non-disruptive migration approach for upgrading the D20, and features:

- PowerPC embedded CPU
- Linux 2.6 operating system
- MySQL database
- 2x Ethernet LANs
- 4x RS-232/485/422 serial communication
- Full graphic HMI functions
- SCADA and relay protocols library
- IRIG-B input and output
- Data traffic monitor and protocol interpreter functions
- IP-based remote Wesmaint to D20
- Routing and firewall

For more information:
Email: info@asatsolutions.com
www.asatsolutions.com
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Cooper Power Systems Presents Secure Substation IED Access with Cybectec Enterprise Solutions

Secure Passthrough reduces costs and service restoration delays

Cooper Power Systems announces the introduction of the new Enterprise Passthrough Manager, a module of Cybectec Enterprise Solutions. Enterprise Passthrough Manager provides an enterprise-level secure single point of access to IEDs for maintenance and engineering.

Enterprise Passthrough Manager includes a client, installed on users' workstations, and a server, installed in a central location, which manages connections between remote IEDs and users on the corporate network. With Enterprise Passthrough Manager, users can access IEDs via native vendor tools, with comprehensive access control.

Cybectec Enterprise Solutions manages all IEDs and communication gateways from one convenient location where device passwords, configuration, history and user access logs are kept.

"With Enterprise Passthrough Manager, authorized users connect to substation devices as if they were in the substation" explains Jonathan Piel, Cooper Power Systems' Global Product Director of Substation Automation. "Even better, the system keeps a trace of all communication exchanges with the substation devices. It provides the unique unifying solution to the NERC CIP requirement for maintaining a user audit trail with diverse legacy equipment.

Enterprise Passthrough Manager's security features permit choosing access rights in groups or down to the single device. Harmful commands can also be filtered out, to protect IEDs against mistakenly sent commands or internal sabotage attempts.

"Being able to hide IED and gateway passwords from users effectively prevents users from logging on the devices from outside the Cybectec Enterprise Solutions system," states Pierre-Luc Simard, Technology Architect for the Cybectec product line. "With Cybectec Enterprise Solutions, we are going beyond NERC CIP. We are offering added value to utilities for their investment in a centralized, secure system."

Cybectec Enterprise Solutions includes automated event retrieval with Enterprise Event Manager and centralized NERC CIP-compliant security with Cybectec Security Server. Utilities that use Cybectec Enterprise Solutions improve the reliability of their network, reduce their downtime and protect their network against cyber-attackers.

Cooper Power Systems, Inc., with revenues of approximately $1 billion, is a division of Cooper Industries, Ltd. (NYSE: CBE). Cooper Power Systems is a global manufacturer of world-class power delivery and reliability solutions for the electrical and industrial markets.

elster

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always a step ahead with proven AMI solutions

Utilities worldwide are faced with the issues of rising fuel costs, deregulation, peak load, grid reliability and conservation. Elster Integrated Solutions (EIS) is playing a central role in addressing these issues by providing proven, reliable AMI solutions to IOUs and smaller utilities alike. A turnkey solution provider, EIS brings together an exceptional team, leading-edge technologies and strategic partners to deliver value added solutions that mitigate risks and accelerate ROI. Our AMI systems and solutions for gas, electricity and water help utilities improve operational efficiencies, reduce costs and support conservation efforts.

Elster's EnergyAxis® System is the largest, true two-way, RF mesh deployment in the world. Proven to work in multi-utility applications ranging from high-density metropolitan environments to lightly populated rural areas, the system supports residential and commercial and industrial applications. Its' standards-based, open architecture is flexible and adaptable to utility needs today and future-proofed to support rapidly changing infrastructure, applications and communications technologies. A proven foundation on which to build reliable demand response, distribution automation and smart grid solutions, Elster's EnergyAxis System is a step ahead of any AMI on the market.

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Through its Energy Automations Solutions group, it is also a leading provider of software, communications and integration solutions that enable customers to increase productivity, improve system reliability, and reduce costs. For more information, go to *www.cooperpower.com, www.cannontech.com* or *www.cybectec.com*.

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Step and Touch Potential Gets Grounded

By Lewis Shaw

For those in the lineman profession every day has the potential to bring the unexpected. Lineman must always think safety first, and be diligent when performing even the most routine tasks. However, even with such precautionary measures, it's hard to protect against unknown hazards.

Every year dozens of lineman are either injured or killed due to unfortunate circumstances involving high voltage mishaps. According to the Safety Fireman's Archive, in 2002 alone more than 50 linemen in the United States were killed while on the job. A preconceived notion in the industry is that you are safe if the line is tagged and there are grounds on both sides of the work area. However, that is not always the case.

Over the years lineman have become quite proficient in creating an equal potential zone at the pole top, however their still remains hazards on the ground that are often overlooked. These can be defined as, "step" or "step and touch" potential. On a pole or in a bucket, we can create and control the equal potential zone. On the ground the voltage becomes difficult to control. The danger becomes the difference in voltage between the workers feet, should they bridge too large a gap. The second danger becomes the difference in voltage between the workers feet and his hand, should they touch an energized object. For example; when operating an un-insulated gang operated switch from ground level, if the switch fails, a line can drop onto the base of the switch. The entire switch, including the handle being used by the worker, would then be energized at full line potential. OSHA has addressed this hazard in the Equi-Potential Zone requirement.

The Occupational Safety and Health Administration (OSHA) requirement 1910.269 states "Equi-Potential Zone: temporary protective grounds shall be placed at such locations and arranged in such a manner as to prevent each employee from being exposed to hazardous differences in electrical potential."

Compliance with the OSHA regulation can be achieved three ways. One option is the use of a Portable Protective Ground Mat. This item offers a means to create an equal potential zone at ground level. The second option is OSHA suggests, is to insulate the worker with equipment such as rubber gloves, or as the third option, preventing access to areas where the hazardous voltages exist. The ultimate goal is to protect the worker from contact.

According to Dick Cole at Hastings, the use of a portable mat for activities like switching processes, splicing cables in trenches, making cable terminations on transformers, opening or closing overhead air breaks, and working on control boxes offers a new level of protection and safety. We had a customer situation not to long ago where the mats were being used at a site where the switchman was performing a routine switching procedure. While performing their duties an incident occurred that had sufficient voltage and current to burn several portions of the mat stitching yet the worker remained unharmed. The internal braid grid and the larger external perimeter braid remained intact. This extra piece of equipment saved the workers life.

For more information regarding this topic please visit:

http://www.cdc.gov/niosh/88-104.html

http://www.osha.gov

http://www.hfgpgrounding.com

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Early Findings from 2008 Newton-Evans Study of Electric Power Control Center Officials Indicate Significant Activities Underway to Develop "Smart Grid" Components and Strengthen Security Measures.

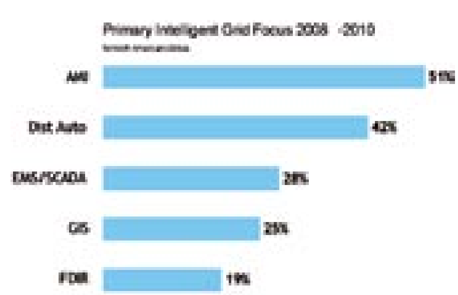
Early findings from the ongoing 2008 study of mission critical, real-time electric utility systems including energy management, supervisory control, and distribution network management include the following:

Communications Protocols:

Despite marketing pressures from global equipment suppliers, the vast majority of North American utilities reporting in to date are not likely to adopt the IEC 61850 protocol beyond experimental testing during the time horizon of this new study. Officials are satisfied with their current communications protocols, led by DNP 3 (both serial and LAN versions) and are using TCP/IP to a greater extent than found in earlier studies.

Smart Grid Activities Underway:

When asked about plans concerning which aspects of an intelligent or smart grid program are being highlighted during 2008-2010, officials are indicating two "hot" areas for investment at this time. These are: advanced metering infrastructure and distribution network automation, including fault detection, isolation and service restoration.



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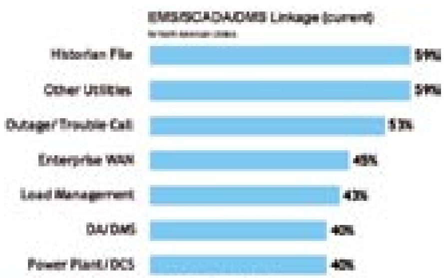
Linking Control Center-Based Systems to the Enterprise:

Linkage to other utility enterprise systems continued to be on the increase, despite concerns for "optimizing security via 'isolation'" with the key to secure control center operations based on limiting links to non-real-time access via periodic downloads to authorized requestors or indirect access to and from the control system via historian files.

The most frequently mentioned plans for additional links this year from control center systems were reported as: NERC compliance reporting systems; outage management systems; geographic information systems and customer information systems.



Outage Management Systems

A majority of large and mid-size North American electric utilities now operate outage management systems (OMS) separately from their SCADA system. About 15% indicated that their outage management applications would remain integral to their SCADA or distribution management system (DMS). Some reported home-grown OMS capabilities are still limited to "trouble ticket tracking".

System Reliability Issues Leading to Action

System reliability issues are being addressed by public service commissions throughout North America. The adoption of performance-based or penalty-based rate structures is still not widespread, but these are available in some of the most populous states and provinces.

Increased Spending on Energy Management and SCADA Systems Upgrades

Much of the industry's increase in spending for control systems-related developments over the most recent two years and planned for the next two years has been as a direct result of regulatory involvement at the federal and state/provincial level. Regulatory concerns have resulted in adoption of programs for renewable energy (renewable portfolio standards), automated metering (advanced metering infrastructure) rate structures, demand response and the like. Each of these in turn can be considered as components of the embryonic "smart grid" as much as can utility efforts aimed at developing distribution network automation, linking geographic information systems to outage management systems, asset management applications and SCADA activities.

More information regarding the ongoing Newton-Evans Research four volume series entitled: ***Worldwide Market Study of Energy Management Systems, SCADA and Distribution Management Systems in Electric Utilities: 2008-2010*** is available here: *lforrest@newton-evans.com* or *eleivo@newton-evans.com* or visit *www.newton-evans.com*.

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Novinium Completes First Phase Of Long Submarine Crossing Rejuvenation

Novinium has successfully completed the first phase of a long submarine cable rejuvenation project for BC Hydro utilizing its patent pending N-REX™ cable injection process for long submarine cables.

The BC Hydro project is a 4.4 km submarine crossing in a remote part of British Columbia running from Sarah Point on the mainland to Cortes Island. On this submarine crossing there are four individual cables: two PILC cables and two 1/0 XLPE compact strand cables. They were installed in 1981 and are the only source of power for Cortes Island, an island about 160 km northwest of Vancouver, British Columbia.

Since these XLPE cables were nearing the end of their expected life, BC Hydro wanted to preemptively rejuvenate these cables and not have to bear the cost of replacement.

In the spring of 2006, BC Hydro initiated rejuvenation of the first XLPE cable by contracting with a supplier of the first generation cable rejuvenation process. After about 8 weeks, the fluid that was being injected stalled and could no longer be pushed through the cable due to increased viscosity when the fluid reacted with water in the cable.

Because these cables provided a critical link to the island, BC Hydro contracted with Novinium in the fall of 2007 to implement its N-REX process, which had previously been utilized on another challenging submarine injection in Puget Sound in the state of Washington. Novinium developed the N-REX process for long submarine cables recognizing that the insulation and conductor shields of these cables would be saturated with water and that this moisture would have to be removed before the cable could be rejuvenated. The N-REX Process consists of three phases: establish flow along the entire length of the cable with N-REX fluid designed to exclude water, supply the N-REX fluid until the insulation is essentially dry, and finally treat the cable with Novinium Ultrinium™ 732 rejuvenation fluid, which will extend the cable life 40 years.

This project was initiated on October 15, 2007 by installing injection adaptors and re-energizing the cable. The fluid first arrived at the end of the cable 108 days later completing the first injection phase. Phase two has begun and will last several months until all of the water is driven from the insulation. Phase three treatment will commence when the cable is essentially dry.

For more information about the Novinium N-REX process see the paper "ADVANCES IN CHEMICAL REJUVENATION OF SUBMARINE CABLES" in the library at *www.novinium.com* or contact Rich Brinton *rich.brinton@novinium.com*.

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INJURIES HURT: ARE YOU TALKING TOO MUCH ABOUT SAFETY?

By Carl and Deb Potter

Many company leaders and managers wonder, "Are we talking about safety too much?" The answer: "No one but you knows." Realize that everyone may be a little overwhelmed with all kinds of communications and distractions. That's why talking about safety *effectively* is more important than ever.

TALKING SAFETY

The fact is that it's important to talk about safety. Injuries are a concern for everyone: They are emotional triggers, and they hurt everyone in the organization and at home. Nobody wants to see another person hurt, and nobody wants to get hurt.

Consider this question: How can you talk about safety in such a way that your employees don't get sick of hearing about it and therefore stop listening?

THE EMOTIONS OF SAFETY

Too often people view and deal with safety in an emotional way. Management gets frustrated when injuries occur and eventually they come out swinging "the safety hammer." Pressure mounts and the managers step-up their discipline (or corrective action).

Recently, a safety director for a large company described a situation where an employee was fatally injured and two others experienced serious injuries. For years the safety director had tried to get management's attention about needed improvements, but without success. Now everyone in the company seems to be a safety expert; every executive has the answer—and everyone has a *different* solution.

When this kind of situation emerges, everything becomes a mess. Finger pointing abounds, and the employees choose sides: Either the problem is technical or it's the people. Employees often begin to be fearful of retribution


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and decide not to report incidents or injuries. Should this scenario ever occur in your company, you need to diffuse the situation by focusing on the safety process.

THE SAFETY PROCESS

In order to maintain safety at a level that prevents injuries, you first have to work on dealing with the emotional issues so the focus is on good decision-making. Realize that safety is both art and science and needs to be treated as such. The "art" is about dealing with people—establishing accountabilities, holding people responsible, and building trust. The "science" of safety is about dealing with behavioral and technical processes. Hazard control is an example of a process that includes both behavioral and technical aspects.

The technical process of safety involves identifying the hazard, abating or controlling it, engineering so it no longer exists, or changing work processes to include the use of protective or personal protective equipment.

When a hazard control has been established, practiced, and proven over time, workers and leaders accept it as normal, and it becomes "common sense" safety. Sometimes acceptance of a new rule or work practice seems to take a while. And often, people don't even understand their own resistance to the process.

THE MILLION DOLLAR QUESTION

Bob, a safety committee chairperson, works in an industry where workers are required to wear protective personal equipment (PPE). When people don't wear the appropriate PPE, the results can be devastating because workers are exposed to the hazards of high voltage electricity. As Bob explains: *"We had someone get hurt last month because he wasn't wearing sleeves with his high voltage rubber gloves. We all know that it's a good work practice to wear the sleeves, so why doesn't everyone just do it? Why don't they get it?"*

"Why don't workers get it?" That's the $1,000,000 question. Experience shows that acceptance of new rules, regulations, and work practices happens faster when workers are engaged in the process of determining the appropriate PPE for the hazards of their job.

In your next safety meeting, take time to engage workers in a discussion about what the hazards are in their workplace. Get them to think both deep and broad about dangers they can encounter. Make a list of these on a flip chart so everyone can see. Then ask what can be done to control each hazard. Be sure to use your safety rule book and documented safe work practices during this discussion. Finally, ask the group "Which of these controls will we always do?" Most of the time, the answer will be "All of them!" When workers get involved in this kind of discussion, it can have a big influence on how your organization talks about safety.

TAKE ACTION FOR A SAFE WORKPLACE

Sure, some people may think your company talks about safety too much, and maybe they're right. Yet safety is an important topic that needs to be discussed. Consider how you can get everyone involved in the discussion and how you can encourage them to take action to ensure that nobody gets hurt. When you do, you're likely to find the answer to that $1,000,000 question.

About the Authors

Carl Potter, CSP, CMC and Deb Potter, PhD, CMC work with organizations that want to create an environment where nobody gets hurt. As advocates of a zero-injury workplace, they are safety speakers, authors, and consultants to industry. For information about their programs and products, see www.potterandassociates.com or carl@potterandassociates.com.

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Radius US celebrates a big increase in the uptake of its NetMan Distribution Automation Solutions.

Radius US has been providing remote control systems to the American electricity industry for nearly a decade. Last year it increased its product offer with the introduction of the NetMan series of remote control SCADA ready motor operators for both pole and pad mounted switches.

The NetMan series of products is designed to operate with a vast range of different air break switches and pad mounted equipment.

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The solutions are flexible and can be integrated via DNP3 with existing SCADA equipment or can be provided with a complete SCADA system.

Solutions are tailored to meet the customer's needs and budgets and are scalable so they are at home in small REC as well as in IOU networks.

The NME range of pole switch solutions has both linear and torsional motor operators with a suite of power options. Further options allow for high or medium speed operating times depending on the requirements of the air break switch and the environment.

The NMS range of pad mounted switch solutions provides a remote operator unit to control from 1 to 9 switches at the same location. The NME is designed to work with motor packs provided by the switch manufacturer, and if none are available Radius can provide retrofit motor packs for most switch types.

Both the NME and the NMS units come with a simple and easy to use operator's panel, which clearly indicates the switch status as well as the health of the supply voltage, battery charging system and the battery. Sophisticated battery management ensures reliable operation while ensuring the minimum service requirements. The batteries are also tested regularly with a configurable time setting and any errors are displayed locally and reported back through SCADA.

Safety is paramount and the operator has the comfort of knowing that they can test the integrity of the battery prior to making a local operation. But for complete safety the units all have a 'hit & run' function that allows the operator to move to a safe distance after initiating a local operation. An audible alarm informs the operator that that a local control is activated.

The Radius Group has always been at the forefront of Distribution Automation and have the knowledge and the products to provide customers with wide area data communication solutions to ensure all of their remote equipment is within reach. Each NetMan unit has the option for a variety of communication solutions, however most customers prefer to use the Radius wide area digital data modems due to its speed, cost and performance.

Radius also provides after market fault passage indicators which integrate into the Radius units in order to provide overcurrent, earth and sensitive earth fault information.

As well as the remote sites Radius has been providing central control units (CCUs) with the option for a touch screen MMI's and automatic restoration logic. The CCU can be used as an 'entry level' SCADA solution or a second tier of control/indication if a SCADA system already exists.

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VANCOUVER - February 2008

Tavrida Electric is pleased to announce the opening of its first North American office located in Delta, BC, Canada. The Delta office will provide sales, engineering support, development and manufacturing for Tavrida's industry leading reclosers and vacuum circuit breakers.

Founded in 1992, Tavrida Electric pioneered the development of magnetic actuator technology for its vacuum circuit breakers. Tavrida is now a major market player and has over the last fifteen years perfected medium voltage breakers to the point of having the smallest footprint and highest reliability in the industry today.

VACUUM CIRCUIT BREAKERS

Most customers unfamiliar with Tavrida products are stunned by how compact the breakers are. Covering a range from 4 kV to 27 kV, the total dimensions of the breakers can be less than a third of comparable units on the market. This makes them equally suited to both new switchgear and retrofit applications.

Certified to a minimum of 50,000 full load close open cycles, with no maintenance for the entire 25 year expected lifespan, Tavrida breakers are solving space and lifecycle cost issues faced by switchgear engineers worldwide.

RECLOSERS

Leveraging their vacuum breaker technology, Tavrida began developing reclosers several years ago in the 15.5 kV and 27 kV voltage classes.

Once again eschewing conventional designs, Tavrida reclosers are extremely compact, lightweight, and highly reliable with up to 30,000 full load operations. Comprised of an aluminum dead tank with a modified Tavrida breaker, the designers have innovated the placement of non-saturable Rogowski coils and six voltage sensors while keeping the tank itself free of any encumbering electronics.

Tavrida's unique products will be on display at the IEEE Conference in Chicago. Contact them at booth #2186 for a demonstration if you will be attending, or *info@tavrida-na.com*, *www.tavrida-na.com*

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Industrial Grade GigE Multi-Service Access Platform Touts Advantages over SONET & SDH

Irvine, CA—TC Communications Inc., the leader in industrial fiber optic network connectivity technology, today announced the commercial availability of its new flagship Gigabit Ethernet Multi-Service Access Platform (MSAP), the JumboSwitch™ product Family.

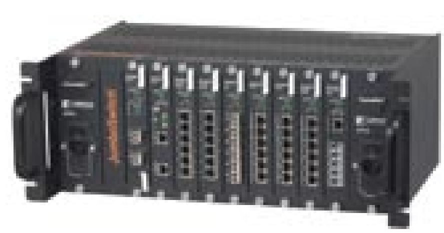
The center piece of the JumboSwitch family is a substation & industrial hardened (-40°C to 80°C), fully-managed and easily scalable Gigabit Ethernet switch that integrates up to seven hot-swappable Ethernet, Voice & Data interface cards onto a Gigabit backbone Ethernet fiber optic network.

Based on the most advanced Ethernet/IP, VoIP and TDMoIP technologies, the JumboSwitch MSAP family offers an efficient, low cost alternative to SONET/SDH network solutions for many applications, and promises straight-forward and simple scalability for any network topologies and sizes.

Compared to the complicated hierarchies of SONET or SDH based systems, the JumboSwitch drastically reduces operational expenses since it totally eliminates unnecessary hardware layers, thus significantly lowered the skill level required for installation, maintenance and troubleshooting.

In the past, SONET and SDH communication systems were the only choices when it came to building mission critical automation and control systems. But, progress in the control, computing and communication technologies has made these TDM based communication systems basically obsolete. The trend is moving towards Ethernet/IP based communication backbones.

The JumboSwitch makes communication network design extremely easy and straight forward. Legacy equipment, e.g. T1/E1, T3/E3, RS-232/RS-485, can co-exist harmoniously on the same platform with more advanced technologies including Ethernet, GigE fiber ports, Turbo Serial for protective relay communication, and LANex, a virtual VoIP PBX without the need of additional Call Managers or SIP Servers.



Management, networking and security features are extensive and include STP, RSTP, SNMP (v1& v2), VLAN, IGMP Snooping, Port Rate Control, QoS, etc. The JumboSwitch supports all popular topologies including redundant ring, bus, string, star and add/drop multiplexing. It is available in 2U and 4U (rack) versions. With TC's proprietary self healing technology, the recovery time for JumboSwitch fiber rings is less than 50ms for any number of nodes.

Configurations are flexible and easily determined by network engineers. For example, it could be configured as a 10/100/1000Mbps Ethernet 42-port redundant ring switch with any combination of fiber or copper ports. Or, it could be configured with 12 channels of Ethernet, 8 channels of T1/E1, 8 channels of phone and 4 channels of RS-232.

All JumboSwitch family interface cards come with optional substation hardened and Industrial Hardened versions (-40°C to 80°C) for extreme environments that meet or exceed all pertinent industrial specifications.

Victor Liang, V.P. Sales & Marketing, noted that the JumboSwitch offers users outstanding price-performance ratios for their communication networks and extreme ease to design, build and maintain.

"JumboSwitch substantially reduces capital expenditures by maximizing bandwidth usage and eliminating unnecessary hardware hierarchies," Mr. Liang said. "And, compared to SONET/SDH solutions, users will be pleasantly surprised by how much it reduces operational expenditures.

Mr. Liang also emphasized the importance of bridging TDM and IP with GigE, TDMoIP, RS-232/485 and VoIP.

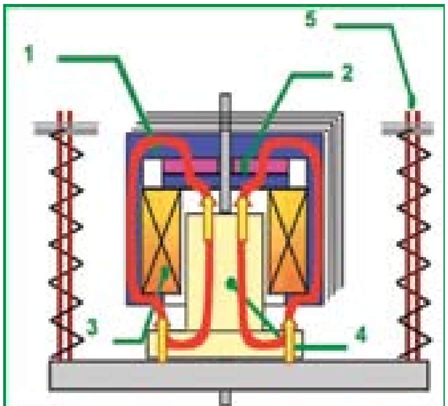
"JumboSwitch is the ideal product for many system and network engineers, that gives them the best of both worlds, TDM and Ethernet/IP, without having to compromise on the project requirements." For more information, visit: *www.tccomm.com*

Circle 65 on Reader Service Card

New Outdoor Circuit Breaker offers Simplified Design with Magnetic Actuators

AREVA T&D (Transmission & Distribution) introduced EOX MAG*netic*™, the company's new line of vacuum outdoor circuit breakers with magnetic actuators in the North American market at DistribuTECH 2008 Conference & Exhibition in Tampa, FL, January 22-24, 2008.

Available in ratings up to 15.5kV, 2000A, 25kA, the EOX MAG*netic* uses a magnetic actuator to operate the circuit breaker. EOX MAG*netic* has an improved design with decreased number of moving parts and requires no adjustments or lubrication at site. Rated for switching capacitive currents up to 1200A, EOX MAG*netic* has been tested according to IEC and ANSI standards for 100,000 mechanical operations. Due to its simpler design and reduced number of moving parts, this breaker is virtually maintenance-free after its initial inspection.



New T plunger actuator – open position
-1- Laminated core -4- "T" plunger
-2- Permanent magnets -5- Opening spring
-3- Closing and opening coil

How it works

Actuators utilise the force generated by a magnetic flux in a circuit to operate the contacts of interrupters. In this design, the actuator stays in the closed position due to the permanent magnets and remains in open position by the force of the opening springs. A single coil provides close and trip actions depending on the direction of the injected current. The required opening speed is reached with the help of the opening springs.

The actuator is composed of a metallic armature (or core), one coil, a mobile plunger (or yoke) going through the coil and permanent magnets. Coils are energised by the discharge of a capacitor through the controller. The main function of the controller is to ensure the charge or the discharge of capacitors (or batteries) in the actuator coils when receiving an opening or a closing order. Monitoring and communications are via an integrated circuit. This specific controller is used for the French TGV railway switch application.

Caption for Image: AREVA T&D's new breaker features a "T" shaped plunger which increases the latching force of the actuator by controlling the magnetic flux. The two surfaces corresponding to the edges of the "T" intersect the flux path. The yellow arrows show the magnetic force. Consequently, the "T" plunger allows reducing the size of the actuator. The new actuator operates like a contactor with the specific requirements of a circuit breaker.

Circle 66 on Reader Service Card

High Voltage Test Expert, Phenix Technologies Introduce 100 kV Portable AC Hipot

The 6CP100-7.5 is the first in a new series of AC Dielectric Test Sets developed by Phenix Technologies offering higher current levels with portable AC Hipot equipment.

The equipment has a unique circuit built into the input of the test set with switchable capacitive compensation which allows for 7.5 kVA output power with 3.3 kVA of input power. "This feature gives the unit a broader range of test applications while maintaining the portability of the equipment", states Phenix rep.

Historically, equipment in this power range would not be considered portable due to its size, but Phenix's 6CP100-7.5 gives the output necessary to do a wide range of field tests with a compact size to offer sufficient portability. See size and weight specs below.

The AC hipot can be used for any application which requires AC Dielectric tests.

For more information contact Phenix Technologies at +1 301-746-8118 / Email: *info@phenixtech.com* or visit *www.phenixtech.com.*

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Valmont Acquires PennSummit Tubular

January 17, 2008

Omaha, NE - Valmont Industries, Inc. (NYSE: VMI), a leading global manufacturer of engineered support structures for infrastructure, mechanized irrigation equipment for agriculture, and a provider of coating services and tubular products, announced today that it has acquired the assets of PennSummit Tubular, LLC, a manufacturer of steel poles primarily for the utility industry. PennSummit, which is headquartered in Hazelton, Pennsylvania, had fiscal year 2007 revenues of approximately $50 million.

"PennSummit is a very strategic acquisition as it broadens Valmont's customer base in the utility industry and strengthens our leadership position," said Mogens C. Bay, Valmont's Chairman and Chief Executive Officer. "As the utility industry continues to invest in the transmission and distribution grid and improve the reliability of electric power delivery, Valmont's investment is especially timely."

Earl Foust, Valmont's President of the Utility Structures Division added, "PennSummit further enhances our geographic footprint with two locations in Pennsylvania. This allows us to better serve our utility customers in the Northeast, where previously we did not have any manufacturing facilities. We have known and respected the PennSummit organization for many years, and will benefit from the capabilities of their seasoned management team. PennSummit Tubular will carry the name Valmont-PennSummit and operate as part of Valmont-Newmark, the Utility Division of Valmont Industries, Inc. Valmont-PennSummit will continue to be led by Raj Pawar, and we are delighted that Raj and his team have decided to join forces with Valmont."

Added Raj Pawar, President of PennSummit Tubular, "We are very excited to join the Valmont team, Valmont's commitment to engineering, quality, service and product development complements the PennSummit culture."

Circle 68 on Reader Service Card

By Michael A. Marullo, Contributing Editor

Replace Existing Normal?

Whenever I make fundamental changes to a word processor document – i.e., changes that affect the basic structure; not just content changes – and get ready to quit the appplication, I sometimes get a message that says, "*Do you want to replace the existing Normal?*" This query refers to the template that defines the style and format of the document I'm currently working on and gives me the opportunity to redefine those rules if I wish to do so. That's actually a pretty cool feature, but I'm always a little apprehensive about making an affirmative reply since that means a lot of the familiar characteristics of the document will disappear and cannot be easily retrieved should I change my mind later on.

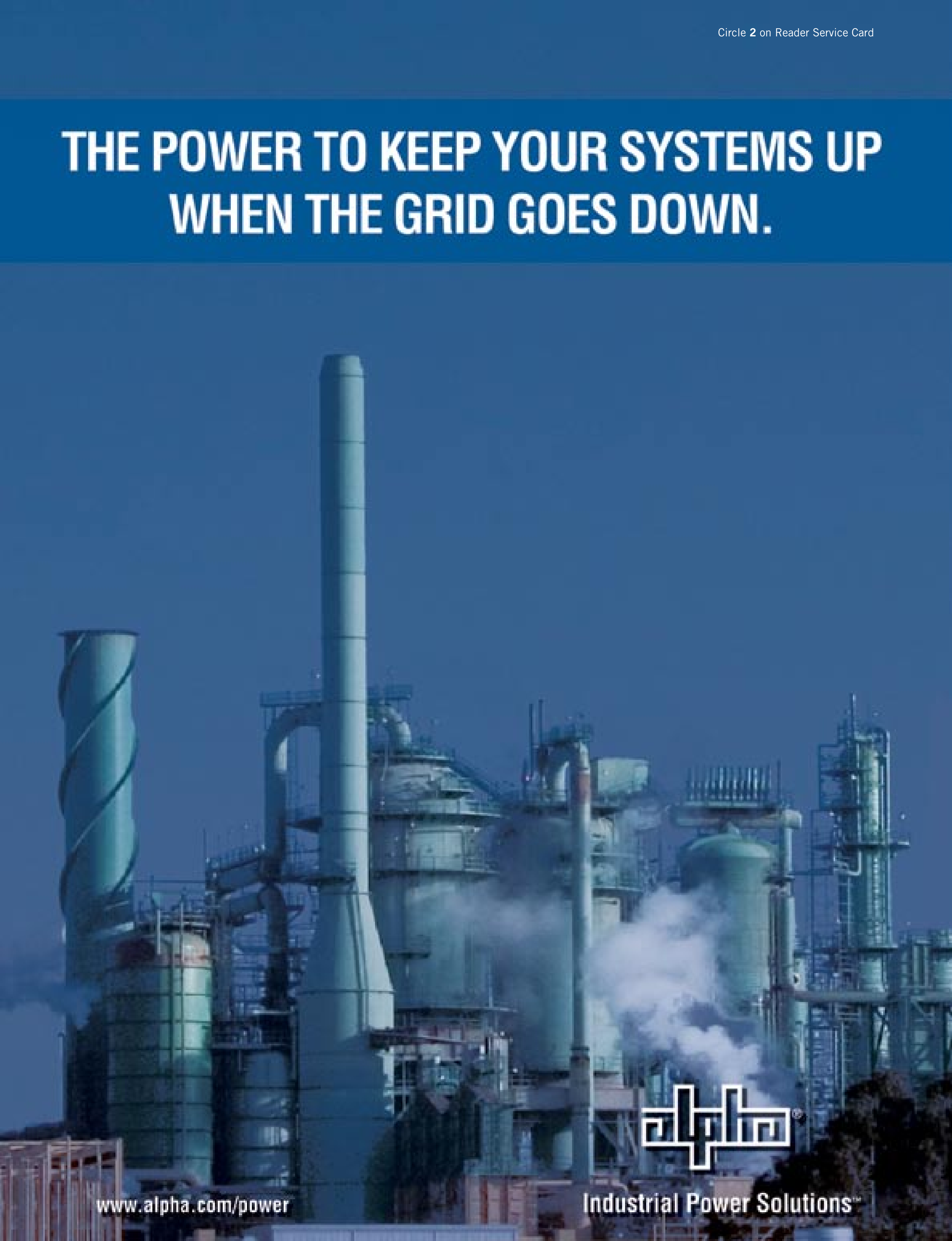
Any time we're faced with making permanent changes like that I guess it's always at least a little bit scary. It's usually that fear of the unknown that intimidates us; the uncertainty of what this 'New Normal' might foist upon us that we didn't anticipate when we agreed to accept it. It seems to me that we're facing a similar dilemma with respect to the grid and the pervasive changes that will need to be made over the next many years if we are to meet the challenge of creating a viable 21st century Smart Grid. (See my interview with ABB executives in this issue for details, insights and discussion about Smart Grid.)

So, I thought it might be interesting to consider some of the changes we might be asked to accept for this New Normal to become a reality. This is by no means an exhaustive list, but rather a tickler to help kick-start the massive transition that will be needed if a New Normal is to ever be realized…

1. **Budgeting** (You show me yours and I'll show you mine.) As regular readers know, I've written about the archaic compartmentalized process that most utilities still use for budgeting automation/IT projects quite a bit in the past, but for the benefit of those who might be new on the scene (and there are many, thanks to aging workforce issues), I feel it bears repeating. Specifically, the notion that projects in the various dimensions of automation/IT – whether it be GIS, CIS, SCADA, Substation Automation AMR, Outage and Work Management, or backbone platform issues like communications and databases – can be planned, specified and procured on an annualized basis and often in total isolation from one another, is in my mind profoundly out of step with today's largely standardized and increasingly interoperable automation/IT environment. Yet most utilities continue dogmatically down this same path year after year. The good news is that we are beginning to see some utilities breaking away from that mold, albeit under duress. With competition for budget dollars being at an all-time crescendo, a lot of folks are finding their budgets crashed by higher priority – yet directly or indirectly related – projects, most often AMI. So get used to the idea of sharing your ideas and plans with people in other departments. You might think that what you do in the GIS department doesn't affect other dimensions of the automation/IT landscape but – let's see, how can I say this gently? Um, YOU'RE WRONG! It's time to stop being so parochial and start including your peers and counterparts in your budgeting processes. This includes formal meetings as well as those discussions at the water cooler. Stop thinking that your project is the universe – it isn't. And, no matter how much money you're spending (or not spending) you WILL impact other automation/IT projects – and THEY will impact YOU, so start talking to each other!

2. **Supplier Relationships** (Suppliers, Vendors or Partners?) At the very beginnings of my research and consulting career, I had a special mentor who quickly railed against anyone referring to system companies as vendors. He maintained that companies that sell commodities are vendors; companies that provide solutions are suppliers. Today, however, I think we can take that to a new level. Companies that consistently provide solutions that work and upon which users routinely rely for technological direction and business guidance are partners. As such, it is passé to perpetuate the adversarial relationship that many users (and some consultants) seem to think is still the proper way to deal with the very same companies that are arguably among their most important strategic relationships.

3. **Financial Metrics** (Price vs. Cost: The definitions are different.) The budget preparation process is certainly not considered by most to be rocket science. However, there is a subtlety that is often lost in the process. That is, the difference between Price (i.e., initial purchase price) versus Cost, as in Total Cost of Ownership or Life Cycle Costs.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How many utilities take these latter factors into account when budgeting, and how many use purchase price as the sole basis for setting budget amounts? Life Cycle Costs are real, and never before have they been as much in focus as they will be over the next decade as thousands of assets reach the end of their useful operating lives. If you pay more for a system that supports closer asset monitoring and allows you to operate those assets beyond their depreciation and/or performance curves safely and reliably, is going strictly for the lowest initial purchase price really the most prudent alternative? Sure, it will take some additional time and effort to make those determinations, but the payoff for doing so can be substantial.

4. **Automation** (It's not just for breakfast anymore!) As I've said many times before, it's time to stop thinking about automation as a luxury or an afterthought that only gets attention when there is clearly no other way out. The reality is, however, that even though old habits die hard, the aging work force and declining infrastructure this industry is facing now will only intensify over the next 7-10 years, making automation an operational imperative. So get on board now, and avoid the last minute rush…

5. **Regulatory Mandates** (They CAN make you do it!) And just in case you think you can escape automating by simply ignoring it, a wave of new regulations and legislation dealing with everything from security enhancement to energy conservation and demand response to vegetation management will soon directly or indirectly mandate automation at numerous levels of utility operations. Sarbanes-Oxley compliance, smart grid initiatives, rigorous new state estimation requirements and more sophisticated energy management and settlement systems are but a few areas that will require automation enhancements, much of which will be on a broad scale.

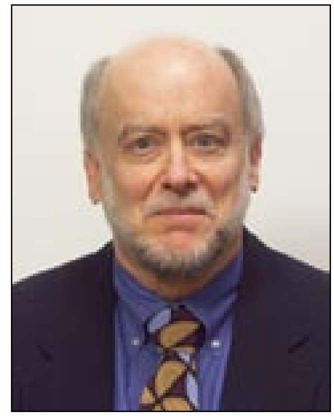
It all sounds good when we talk about change in the abstract, but when it comes down to actually *changing*; a fundamental shift in planning, policy and practice is in order. Are YOU ready to replace the existing normal? ■

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 co-founder and Director of Research & Consulting for InfoNetrix LLC, a New Orleans-based market inteligence firm focused on Utility Automation and IT markets. Inquiries or comments about this column may be directed to Mike at MAM@InfoNetrix.com.

Mining the Corporate Data Domain Safely and Securely Across the Enterprise

By Paul Cassingham, Entergy Services, Inc.
David Allen, Nobadeer Software



In these times of increasingly stringent regulatory compliance reporting by publicly-held utilities like Entergy Services Inc. in New Orleans, Louisiana, the transmission and distribution (T&D) department requires an auditable and reliable source of historical data with no gaps. However, besides conventional database requirements, they also needed an auditable source for the database metadata; that is, the descriptions of the data contained in the database.

Moreover, the various departments within T&D often have divergent needs for SCADA numerical and alarm data. For instance, system planners need SCADA numerical data – typically hourly data organized by feeder – to determine future system construction requirements. Likewise, the maintenance staff needs near real-time data and alarms to closely monitor equipment in need of maintenance so that in the event of a malfunction or failure, they can react quickly to resolve any problems. Finally, the operations department needs near real-time data and related alarms as well as numerical data to ensure that the system is operating normally and to identify potential overloads or other system anomalies when planning system changes.

Lastly, the ability to meet all of these demands for data in a timely manner without allowing direct access to the operational Energy Management System data was of paramount importance to Entergy from an EMS security standpoint. After searching the marketplace for a solution that could satisfy all of these requirements, Entergy selected Pegasus RDS™, a real-time data store, provided by Nobadeer Software Inc. of Longmeadow, Massachusetts.

The Challenge

In the 1990s Entergy developed tools in-house to pull different types of data out of the operational SCADA system, store it and/or share it to various departments. One in-house tool in particular has been used by hundreds of internal users for day-to-day equipment monitoring and viewing of historical data. A valuable feature of the in-house solution, however, was that it stored all of the data, all the time. Unlike solutions that require values to be selected and saved ahead of time, this system stored all the data so that it all could be examined anytime, after the fact.

Yet although the in-house developed tools were a popular success, they had limitations in terms of functionality and reliability. For example, there was no reasonable ability to systematically obtain and analyze the data programmatically outside the original user interface; the biggest reliability issue was a lack of data feed redundancy, which resulted in gaps in the data – a serious deficiency.

Looking for Answers

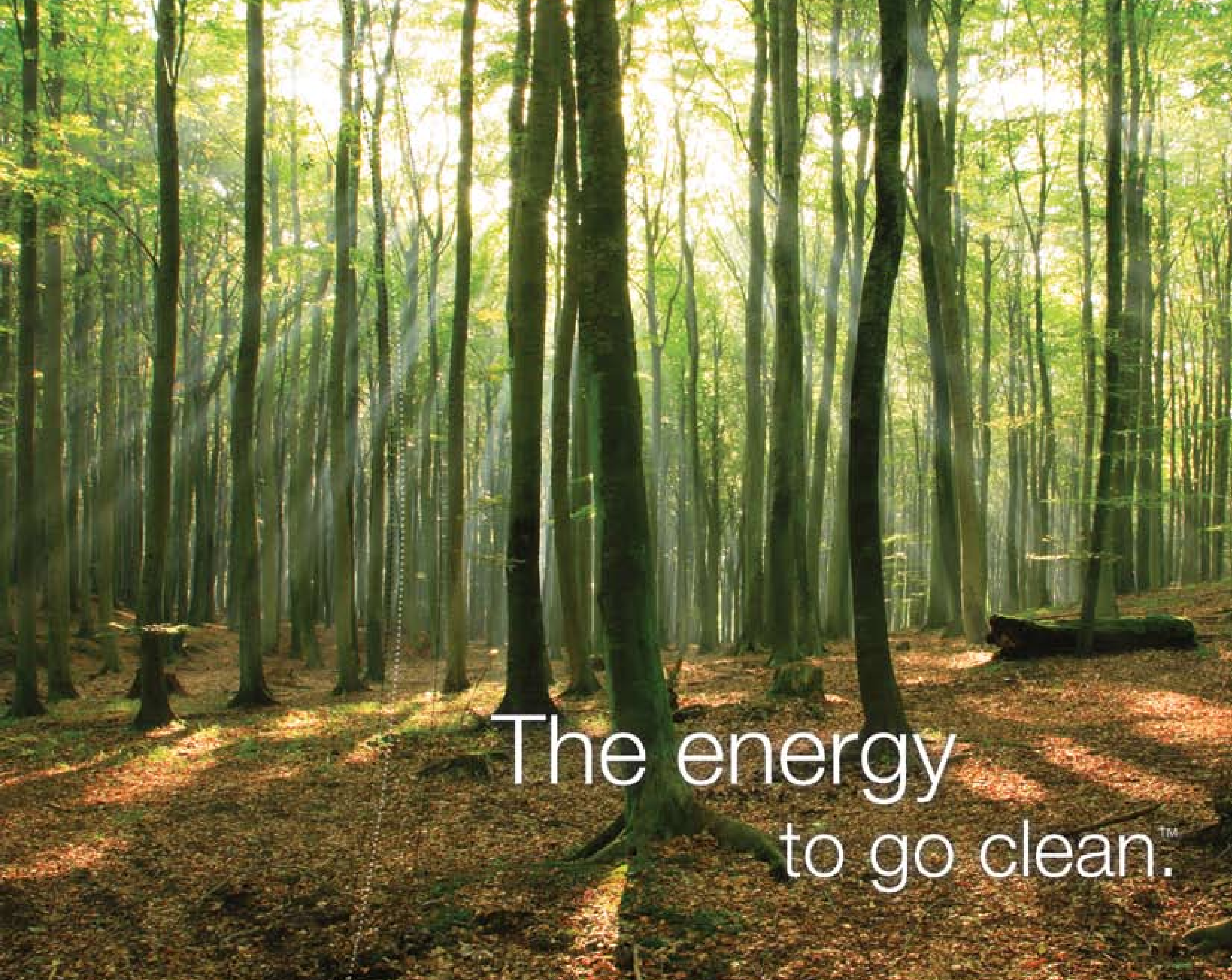
In 2003 Entergy made the decision to replace the in-house tools with an industrial quality application that would meet its functionality and reliability goals. Existing data historians were examined and found to be good general-purpose systems that require the user to re-define and remap their data into a new framework.

Given Entergy's resource constraints and the frequency of database updates, the additional burden of remapping large data sets wasn't deemed practical. Instead, a system that was tightly integrated with the existing SCADA system was needed to avoid undue maintenance and duplication of effort.

The Solution

After researching suitable products among qualified vendors in the marketplace, Entergy selected Nobadeer Software to develop a technical solution based on the desired functionality and the following set of real world objectives:

- Capture all of the data, all the time.
- Zero maintenance required.
- Keep unauthorized personnel out of the security perimeter.
- Provide programmatic access to the data store.
- Incorporate modern application development standards thereby providing stability, resiliency, and robustness in the platform.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After a thorough review and discussions of Entergy's needs, coding was initiated in 2003. The resulting data storage and retrieval system – called Pegasus RDS™ – was put into service at the first of Entergy's regional control centers in 2004, and was soon storing data at all four regional T&D centers and the central transmission operations center. Since then, the system has been expanded to include a number of reporting and data analysis tools.

Automation Breeds an Unforeseen Bonus

One of Entergy's requirements was that the system be maintenance-free, an unforeseen result of which was the ability of the system to audit database changes. This feature has been enhanced by adding a set of reports that allow a user to compare the contents of any two SCADA databases that have been put into operation since the system started, providing a complete audit trail of database changes.

Entergy's Doug Dollar, Project Lead in West Monroe, notes that this feature has saved his team valuable time. "The new system provides what SCADA Support Analysts were manually recording into spreadsheets," said Dollar. "A review of the report provides a quick double check that all desired changes have been made correctly." [Refer to Figure 1]

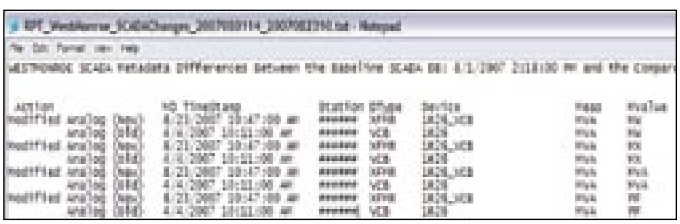

Figure 1: Pegasus provides a high integrity audit trail of all SCADA object actions via online screens and exported reports. The system clearly shows old vs. new values when a SCADA object is modified. In this report example, four analog data points had their Device Type changed from VCB to XFMR on 8/4/2007.

All the Data, All the Time

Every alarm, status, analog, analog limit, and accumulator in the database, including calculated values, is stored by the system. Because the data is captured periodically rather than by exception, the load on the EMS host is steady rather than a series of peaks and valleys that can wreak havoc on system performance. The stability of the system was proved during hurricanes Katrina and Rita when every data change and alarm was captured during these times of extreme system activity.

Included at each site is a fully redundant system that regularly collects the data from both the primary and secondary EMS machines. The system takes these two data feeds and decides later which one to use. [Refer to Figure 2] This approach has resulted in no substantive data losses since the system went into operation, with everything on-line and available for use. This data remains available for historical reference, forensics or other diagnostics long after any event occurs; i.e., the data is not subject to the "roll-off" that can sometimes happen with archival systems. The hardware was sized for five years of on-line storage, but keeping data for longer periods simply requires installing additional disk capacity and changing one system parameter.

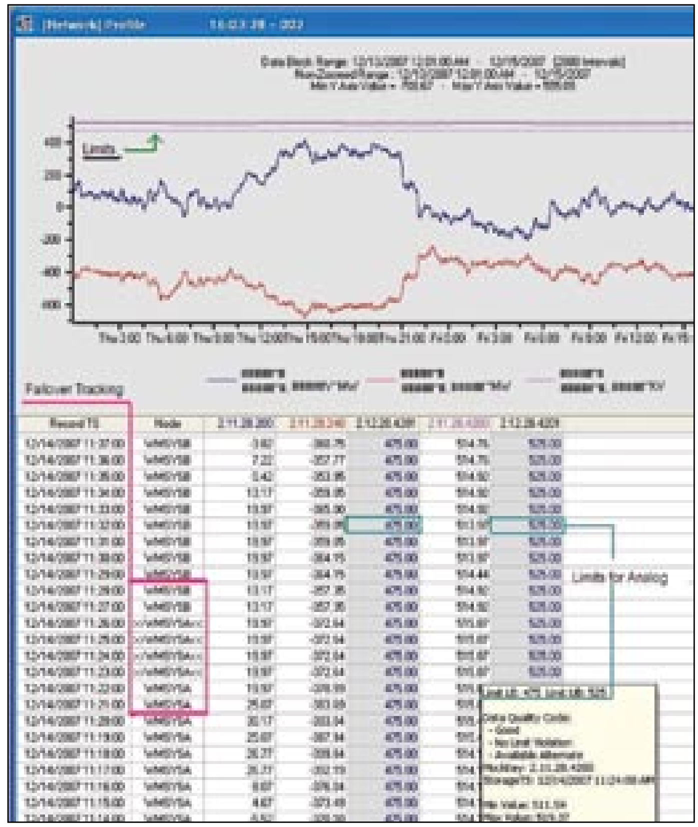

Figure 2: SCADA measurements are tightly integrated with the EMS information, including the enabled host, limit pair(s), quality codes and system alarms. The screenshot shows a typical system failover from node WMSYSA ("System A") to WMSYSB ("System B"), identifying data captured where neither node is enabled with the symbols ">> <<". Also shown are the actual limit values for one of the displayed analogs.

Moreover, sampling data frequently and storing the median of the sampled data further enhances analog data reliability. This has the effect of removing erratic samples and results in a more statistically accurate representation of the measurement.

No Maintenance Required

To come as close as possible to meeting the zero-maintenance design goal, it's necessary to keep track of devices over time, even when they have name changes. Name changes may occur, for example, if a Gas Circuit Breaker (GCB) is being replaced by a Vacuum Circuit Breaker (VCB). The solution is keeping an "invariant key" for each measurement in the system, and automatically remapping devices to the keys when a new SCADA database goes online. There is little if any staff intervention in this process.

Once a new SCADA database is put on-line, the system automatically stores the contents of the new database and all data collection and storage applications run though the update without further staff involvement, handling all necessary re-mapping on the fly. New data is then available for display, and points with database name changes automatically return an unbroken set of data across all time stored in the database. Since there are frequent name changes on the Entergy system, this feature is invaluable from both maintenance and data consistency perspectives.

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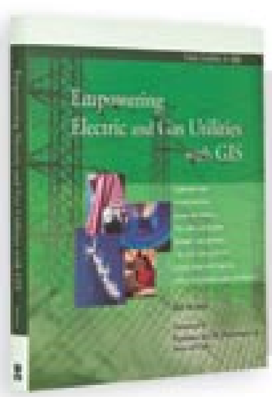

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In addition to the automatic mapping, the system also handles all necessary database partitioning, indexing, trimming and log deletion automatically, so that no database administration time is needed to maintain the system.

Although the system does occasionally require some maintenance by Entergy and/or Nobadeer, the zero maintenance target has very nearly been achieved, especially when considering the volume of data captured.

Preserving the Security Perimeter

Pegasus has shown it can reliably collect, store and provide all of the SCADA data to its internal users, so Entergy is now in the process of retiring all of the old data gathering applications from the EMS. In the future, the system will also provide information to all authorized T&D users outside of the operations arena as well via the typical corporate desktop. This helps Entergy meet the NERC Critical Infrastructure Protection (CIP) guidelines by providing a clear separation (just two logical connections) between critical and non-critical assets.

Access to the Data Store

In addition to a desktop client and the ability to move data from the client to other desktop applications like Microsoft Access and Excel, all data is available to other programs using a simple application programming interface (API). Bulk exports of data are supported by a dedicated Exporter application that uses this API. The Exporter allows the user to gather, for example, all megawatt readings from a region for a year with a simple command script. The API is also used by data mining applications that operate on the data store.

Application Development Standards

Application development used modern tools and techniques, with its processes programmed to take advantage of new multi-core CPU technologies. The system is very stable, scalable, and shows excellent performance with over one trillion records on-line. As the on-line database grows, the data retrieval time remains constant – a feature that required extensive effort to design and implement but that is invaluable in such a dynamic data environment.

Enabling Success

The storage, retrieval and audit capabilities of the system are field proven with over three years of on-line service. The ability to pull massive sets of reliable, complete data from the system is being increasingly recognized and used by the planning and maintenance organizations at Entergy. Some of the successes include:

- Automated audit tracking of the SCADA database changes
- Reducing the need for SCADA support personnel to be involved when T&D planning, maintenance or management organizations request archived SCADA data across a wide time range. Compared with the legacy system, which could only piece together data on a day-by-day basis, a reliable and flexible interface to data on daily, monthly or longer time frames is now readily available.
- Reliable and easy access to data has allowed various departments to:
  - Start fine tuning alarm levels,
  - Determine which transducers are out of calibration,
  - Obtain data to support load balancing decisions that have a direct effect on reliability,
  - More effectively support the system design team,
  - And, identify "chattering" alarms to speed up repairs.

Next Steps

At this point development is focusing on data mining applications that take advantage of the tight integration of the system with Entergy's SCADA system to provide reports and automated analysis of how well the T&D system is performing. Examples of data mining reports already developed and going into production in Q1-2008 include:

- "Sticky" circuit breakers (i.e., breakers not responding properly to operator commands). One click on this report brings up the list of breakers with problems, and selecting any of these brings up the OPEN/CLOSE history of that device for the month, showing each status change and any related operator command. [Refer to Figure 3]

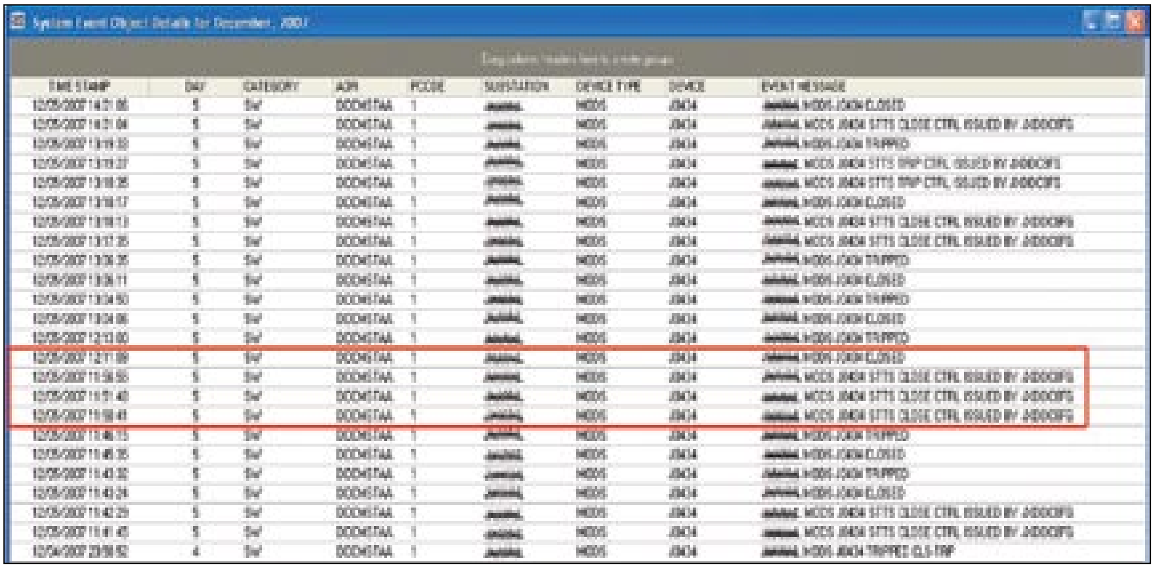


Figure 3: The system provides numerous data mining reports. This example shows a drill down (detail) from the 'No Response' report, flagging a problem by showing that Device J0434 required multiple close commands before the breaker operation was completed.

- Devices changing state most often, sorted by frequency. This allows a quick drill down to see which field points require maintenance.
- Alarm limits most frequently violated, also sorted by frequency. This report can be used to check that alarm limits are appropriate, or quickly see which devices are most often operating beyond preset limits.

These reports also allow users to drag and drop columns so they can organize the data any way they want; for example: by substation; by device; by date; by area of responsibility; or any other column.

Additional sophisticated reporting providing mathematical analysis of analog values is under development. These reports include:

- Analogs that are mathematically erratic using statistical methods
- How long individual devices operate at or near typical operating limits, and by how much

Further analysis based on pattern recognition, applied to the power system data store, will be used to look for patterns, statistical advantages, and inference between variables. This area provides an exciting chance to break new ground in real-time analysis of the Entergy power system in the coming years.

The solution provided to Entergy is a low maintenance, industrial quality platform that enables:

- Ready access to a vast storage of historical data and events
- Forensic analysis of major electrical grid events
- Preventive maintenance insights and benefits
- High-integrity automated auditing

Being able to specify real world requirements, in addition to functional needs, and getting a solution designed and implemented around those requirements has made this project a success while also helping to alleviate Entergy's resource constraints. ■

About the Authors

Paul Cassingham *is Manager of Application Management for Entergy's Transmission Business Unit and is responsible for EMS/SCADA and related applications that support engineering, operations and maintenance functions within Transmission. Paul holds a Bachelor of Science degree in Computer Engineering from Iowa State University and has over 27 years of experience with EMS/SCADA systems for Entergy.*

David Allen *has 30 years of experience in real-time data collection. After many years with Texas Instruments and more recently, Areva T&D, he is now a Senior Consulting Engineer with Nobadeer Software, Inc. of Longmeadow MA. David holds a Master's degree in Computer Science from the University of Washington.*

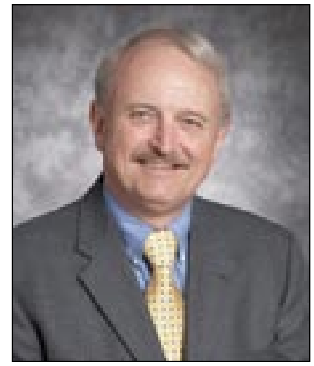
Greg Scheu

The 2008 Automation/IT Leadership Series

By Michael A. Marullo, Automation/IT Editor

ABB

Greg Scheu, Senior VP-ABB Power Products and **Mike Barnoski**, Senior VP-ABB Power Systems, North America



Mike Barnoski

In this issue, we are privileged to be able to share the thoughts and insights of two key executives from ABB's North American Power Products and Power Systems divisions. Greg Scheu was recently promoted to Region Division Manager and head of Power Products after successfully heading ABB's Automation Products division the last several years. His counterpart is Mike Barnoski, Region Division Manager and head of ABB's Power Systems Division. Together, these senior executives are responsible for substantially all of the company's power-related products, systems and services across North America.

As one of the most prominent and influential suppliers in North America as well as on a global scale, ABB is a company that is routinely on the leading edge of breakthrough technologies and new business strategies associated with both power generation and power delivery. This interview focuses on energy efficiency and provides an expanded and multi-dimensional view of initiatives for the rapidly-evolving Smart Grid that I think you will find both interesting and enlightening.

– Mike Marullo, Automation/IT Editor

EET&D: I've heard that from a generation perspective – clearly a key business area for ABB – power production can be fairly inefficient. In fact, I understand that as little as 30-35% of the energy produced from coal actually ends up as electricity at the end of the process in many cases. Do you find that inefficiency characteristic to be present in the transmission and distribution operations of utilities as well?

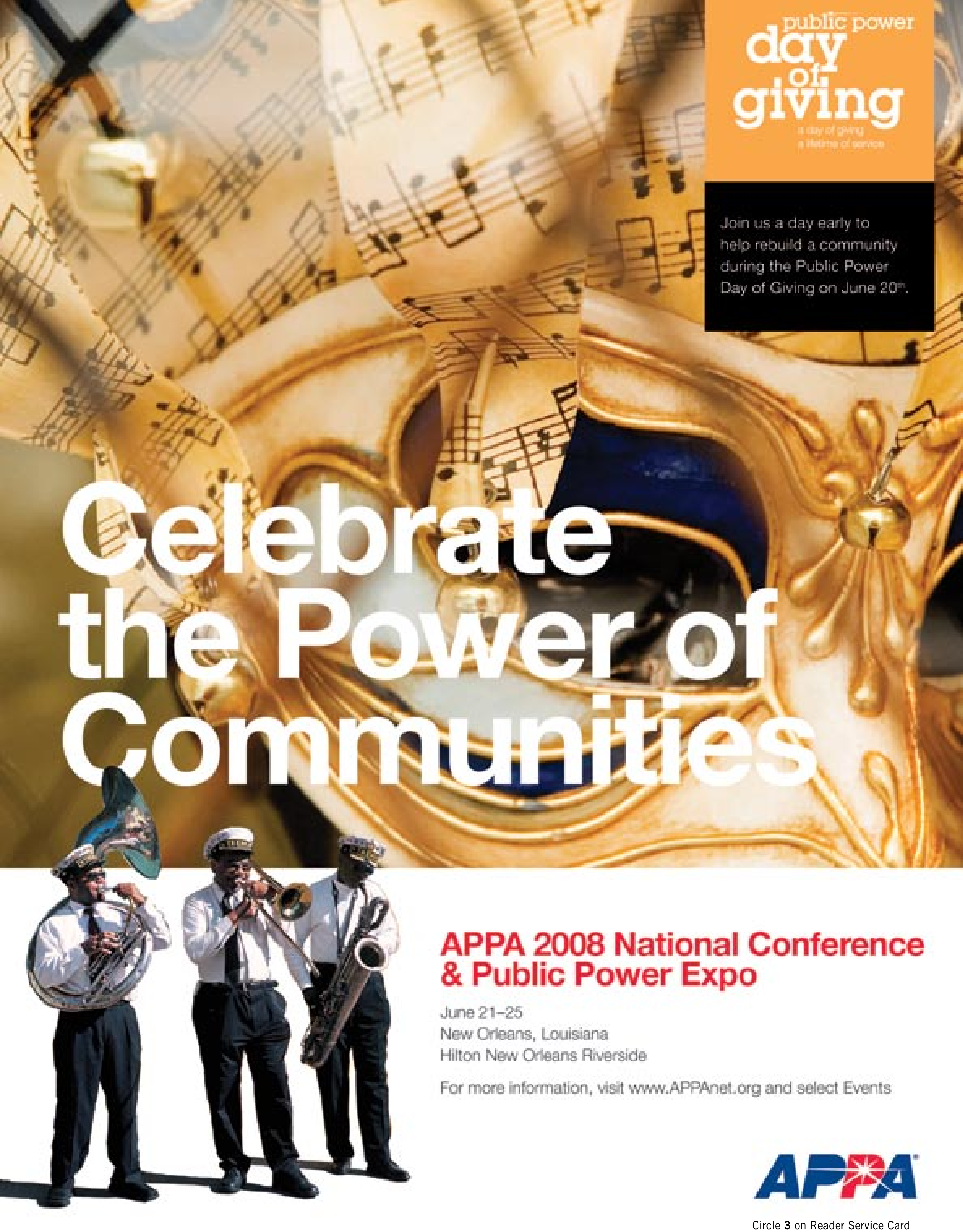
Barnoski: To gain an appreciation for the impact that improved efficiency can have, it helps to look at the price that's paid for inefficiency, and nowhere is this more apparent than in the generation of electric power. Typically, the process converts the latent energy in a fuel stock (e.g., coal, gas, uranium) into mechanical energy in a generator and ultimately electrical energy. However, other generation sources like wind and hydro-power use the mechanical energy of moving masses of air or water to produce electric energy. Still other devices, such as fuel cells, use chemical reactions to generate electric energy. In all of these cases, though, some of the input energy is lost in the process.

The efficiency of generation varies widely with the technology used. In a traditional coal plant, as you mentioned, only about 30-35% of the energy in the coal ends up as electricity on the other end of the generator. So-called "supercritical" coal plants can reach efficiency levels in the mid-40s, and the latest coal technology, known as integrated gasification combined cycle (IGCC) is capable of efficiency levels above 60%. The most efficient gas-fired generators achieve a similar level of efficiency.

Obviously, though, even at 60% efficiency there is a tremendous amount of energy left behind in the generation process. That represents a higher cost of production for the generator, as well as a substantial waste of limited resources. There is, therefore, tremendous economic and ecological incentive to improve the efficiency of power generation so that more of the energy content of the input fuel is carried through to the output electricity.

EET&D: So, does that mean that there are specific costs that can be tied to the inefficiencies in the T&D system? If so, where do utilities have the greatest potential financial exposure?

Scheu: Once electric energy moves through the transmission and distribution system, some of the energy supplied by the generator is lost due to the resistance of the wires and equipment that the electricity passes through. Most of this energy is converted to heat. Just how much energy is taken up as losses in the T&D system depends greatly on the physical characteristics of the system as well as how it is operated. Generally speaking, T&D losses between 6% and 8% are considered normal.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It's possible to calculate what this means in dollar terms by looking at the difference between the amount of electric energy generated and the amount actually sold at the retail level. According to data from the Energy Information Administration, net generation in the US came to over 3.9 billion megawatt hours (MWh) in 2005 while retail power sales during that year were about 3.6 billion MWh. T&D losses amounted to 239 million MWh, or 6.1% of net generation. Multiplying that number by the national average retail price of electricity for 2005, we can estimate those losses came at a cost to the US economy of just under $19.5 billion.

Congestion charges represent another significant cost of inefficiency in the T&D system. Congestion is the result of a number of factors, notably a lack of adequate transmission investment and an increase in bulk power transactions in competitive energy markets.

The California Independent System Operator reported congestion costs of $1.1 billion in 2004, $670 million in 2005, and $476 million in 2006. So, despite the progress being made, the cost of inefficiency in the T&D system is still quite significant. However, a more robust T&D system can provide a level, congestion-free playing field on which generators can compete.

EET&D: What is demand-side (i.e., as opposed to supply-side) energy efficiency, and how successful have demand-side efficiency measures been in your experience?

Scheu: The average person would likely point to energy consumption as the point where efficiency measures can be applied. Most of these discussions are on the supply-side, but there are definitely demand-side energy efficiency efforts as well.

Most people are probably familiar with the Energy Star program, or with the increasing popularity of compact fluorescent light bulbs. But the single largest consumer of electric power is the industrial motor, which is used to run everything from assembly lines to compressors to the fans that blow air into the combustion chamber of a coal-fired generator.

EET&D: It's estimated that fully 65% of industrial power is used in motors of various sizes, most of which run at full speed whenever they are turned on. What can be done to alter that huge operational inefficiency?

Scheu: The vast majority of industrial motors are controlled by fixed-speed drives that cannot alter the speed of the motors they control. Variable speed drives ramp the motor's speed up or down to meet the requirements at a given moment in time. The resulting energy savings can be enormous. VSDs can reduce consumption by as much as 60%, which in energy-intensive facilities can equate to millions of dollars a year in energy costs.

EET&D: What can you tell us about some of the newer, more advanced technologies and measures that have the greatest potential for improving efficiency in the transmission environment?

Scheu: One efficiency measure aimed primarily at the utilities is a US Department of Energy initiative aimed at implementing new efficiency standards for distribution transformers. There are over 40 million distribution transformers in service today in the US and are among the most ubiquitous and the most standardized pieces of electrical equipment.

The proposed standards will have a relatively modest impact on the efficiency of a given transformer, around four percent over current models. However, when this incremental gain is multiplied across the thousands of units operated by even a small utility, the result is impressive.

Barnoski: At the transmission level, there are numerous technologies that are already being applied to boost efficiency in transmission, and still more that have yet to reach full commercial implementation. Some of these technologies include:

- **HVDC:** Most of the transmission lines that make up the North American transmission grid are high-voltage alternating current (HVAC) lines. Direct current (DC) transmission offers great advantages over AC, however: 25% lower line losses, two to five times the capacity of an AC line at similar voltage, plus the ability to precisely control the flow of power. In addition HVDC underground applications eliminate the issue that many environmentalists have with overhead AC lines.

- **FACTS Devices:** FACTS – a family of power electronics devices known as Flexible AC Transmission Systems - provides a variety of benefits for increasing transmission efficiency. Perhaps the most immediate is their ability to allow existing AC lines to be loaded more heavily without increasing the risk of disturbances on the system. Actual results vary with the characteristics of each installation, but industry experience has shown FACTS devices to enhance transmission capacity by 20-40%.

- **Gas-Insulated Substations (GIS):** Gas-insulated substations essentially take all of the equipment you would find in an outdoor substation and encapsulate it inside of a metal housing. The air inside is replaced with a special inert gas, which allows all of the components to be placed much closer together without the risk of a flashover. The result is that it is now possible to locate a substation in the basement of a building or other confined space so that the efficiency of high-voltage transmission can be exploited to the fullest extent.

EET&D: The Business Roundtable's Energy Task Force T&D Working Group, chaired by ABB, recently published a list of energy-efficient actions and technologies. Can you share what some of those technologies are?

Scheu: This working group recently published a summary of efficiency-enhancing actions and technologies. Technology options for improving effects of T&D may be classified into three categories:

1. Technologies for expanding transmission capacity to enable optimal deployment and use of generation resources
2. Technologies for optimizing transmission and distribution system design and operations to reduce overall energy losses
3. New industry standards for energy efficiency power apparatus.

Some specific measures likely to employ these technologies include:

- Distributed generation/Microgrids
- Underground distribution lines
- Reduction of overall T&D transformer MVA
- Energy storage devices
- Three phase design for distribution
- Ground wire loss reduction techniques
- Higher transmission operating voltages
- Voltage optimization through reactive power compensation
- Asset replacement schedule optimization
- And, power electronic transformers.

EET&D: Where are the most important benefits that can be derived from improved energy efficiency within the power T&D infrastructure?

Scheu: The "business case" for energy efficiency is fairly straightforward: Using less energy means paying less for energy. But a simple cost-benefit analysis might overlook some very important benefits that efficiency brings.

Greater energy efficiency in the T&D system means lower emissions in generation to deliver the same amount of consumed energy. Moreover, improved T&D efficiency will allow for the support of renewable generation sources that are cannot currently be accommodated at many injection points on the grid.

Within the context of the power system itself, it's important to recognize how interrelated energy efficiency is with grid reliability. In many areas of the US, transmission constraints have reached the point where they not only cost consumers billions of dollars in congestion charges; they actually threaten the integrity of the power system itself.

Over the past twenty years, the situation has continued to deteriorate to the point where now the question of installing a new line is nearly moot in some locations. By the time it was completed, demand would long since have outstripped the ability of the local grid to meet it, so a short-term solution must be implemented in the interim.

As the reliable supply of energy, especially electric energy, continues to grow in importance, the potential impact of energy efficiency cannot be overstated. With the array of technologies and methodologies now available, efficiency stands ready to play a much larger role in the energy equation.

EET&D: The power infrastructure and subsequent equipment has aged over many decades of use, and there are risks associated with it. How can the efforts from many in IT, software and network management help shape the direction of what we now refer to as the Smart Grid?

Barnoski: IT, analytical software, and the ability to monitor the network in a real-time mode will enable operators to know what is actually taking place on the grid that is creating certain conditions or occurrences. Operators will be able to make much better informed decisions in much shorter time periods to reduce the risk of brownouts, blackouts and other system disturbances whose underlying cause is often obsolete equipment on the system.

Scheu: The concept of "intelligence" as applied to power systems is centered on the idea of pushing sensory and analytic capabilities further down the system hierarchy. In a smart grid, more can be done locally at the substation - or even the device level - sometimes without involving the operators or the computing resources in the control center. Utilities are already implementing smart devices in various applications (e.g., fault detection). The smart grid concept simply extrapolates this trend to encompass the entire grid.

EET&D: What are the key characteristics that separate the intelligent grid from legacy power systems?

Scheu: Some of today's networks do incorporate certain "smart" elements, but generally not in a comprehensive way. The intelligent grid, therefore, is *comprehensively*:

- **Self-healing**, being able to manage itself with less reliance on operators, particularly in terms of quick response to changing conditions
- **Predictive**, in terms of identifying potential outages before they occur and also in applying operational data to equipment maintenance practices
- **Real-time**, in terms of communications and control functions
- **Optimized** to maximize reliability, availability, security, efficiency and economic performance

All of this is predicated on the widespread deployment of technologies designed to bring the required level of intelligence to various grid components as well as the communication and control systems that administer the system as a whole.

EET&D: What are the basic principles that underlie all of the intelligence technology being developed today?

Barnoski: There are a number of specific technology areas that enable the smart grid, but perhaps more importantly, there are two basic principles that underlie all of the technology. First is the idea of interoperability and by extension, open systems. For several years now, there has been a decisive move in the utility IT world away from proprietary standards and protocols toward commonly used commercial products. This is especially true of the non-specialized system components (e.g., databases) where off-the-shelf tools are taking the place of custom-developed applications.

The second underlying principle is real-time, two-way communications, which in turn facilitates the functionality improvements envisioned by the smart grid concept. A highly robust communications function is therefore a prerequisite for all of the detection and analysis that characterize the smart grid.

EET&D: What are the benefits to utilities and to customers of automating more of the operational decisions that in the past were made by human beings?

Scheu: Improved interfaces and decision support amplify human decision-making, and transform grid operators into knowledge workers. This speaks to the transformation of the utility enterprise that will come with the realization of the intelligent grid.

By automating more of the operational decisions that in the past were made by human beings, operators can focus their attention on the larger decisions that genuinely require operator intervention. By the same token, there are actions that intelligent system can take that would be impossible for a human being to replicate. So, one of the ways the intelligent grid optimizes performance is by leveraging both human beings and machines to do what they do best.

EET&D: How are automation and IT personnel meeting the growing demand for intelligence in the grid infrastructure?

Barnoski: Some specific examples of how smart technologies – and the practices they enable – can impact the operation and overall health of the grid.

- Real-time situational awareness and analysis of the distribution system can drive improved system operational practices that will in turn improve reliability
- Feeder automation (FA) improves reliability indices and helps utilities avoid penalties. FA enables fault location and preventative failure analysis to avoid costly outages. FA can also enhance work force management to increase productivity and improve safety.

- Substation automation (SA) provides a data warehouse for information on equipment condition from the feeder to the substation. SA enables the ability to plan, monitor, and control equipment below the control center.
- Smart communication-enabled devices can provide necessary information that enable better-informed operation and maintenance decisions
- System analysis and loss evaluation can improve efficiency of grid operations. Business case evaluation and tailoring of technology applications to fit business needs can further drive better use of resources.

EET&D: What are some of the drivers for adopting smart grid technologies?

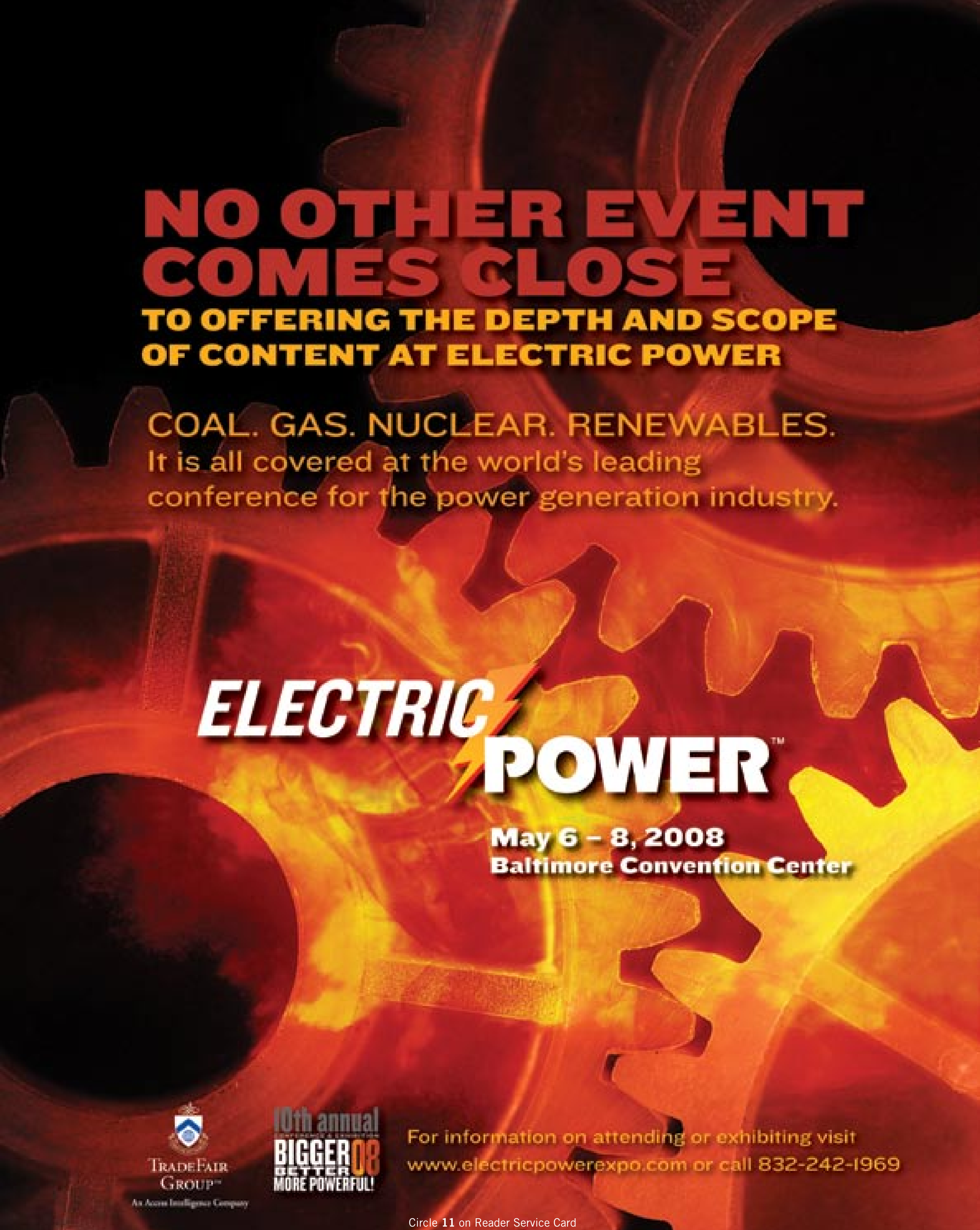
Scheu: There are already strong drivers for utilities to adopt smart technologies and update aging infrastructure. From the regulatory side, the Energy Policy Act of 2005 requires state regulators to investigate advanced metering, time-based pricing and demand response programs.

The Energy Security and Independence Act of 2007, Title XIII, is specifically focused on smart grid functionality providing for the encouragement of demonstration projects, federal grants and matching funds for smart technology adoption.

Currently, the application of smart grid technologies is often approached in an isolated, piecemeal fashion. Automatic meter reading (AMR) is often the first phase of an intelligent grid initiative. These projects involve huge capital outlays – one study put the average at $700 million – and are typically driven by regulatory policies designed to improve customer pricing and reduce system costs. AMR can, however, and often does, act as the gateway to larger, more ambitious improvements. With the communications infrastructure in place, feeder automation, substation automation and other operations improvements can be justified.

EET&D: So, with a rational approach, it would seem that the business case for smart grid enhancements builds upon itself as more elements are added. With economic, regulatory and environmental forces driving it forward, what is it going to take for the grid of the future to become the grid of today?

Scheu: The T&D system is an efficiency enabler. With well-designed systems, consumers should be able to purchase power from the cheapest, most efficient or least polluting source. Reality, however, is not quite there yet. But the evolution to a smart grid, starting now, will enable a much more efficient energy value chain. You can be assured that we will do whatever we can to ensure it happens as quickly as possible using tools that are technologically advanced, affordable and easy to deploy and support. ■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Key issues for Implementing a Prudent Control System Cyber Security Program

By Joe Weiss, PE, CISM, Applied Control Solutions, LLC

The goals of a prudent control cyber security program should be to help make the utility/entity more secure, maintain and when possible, *improve* system reliability and availability, and meet regulatory requirements. In the past, these requirements have been met by prudent engineering design considering all appropriate system challenges (this includes the N-1 criteria and appropriate redundancy), appropriate testing, appropriate polices and procedures, appropriate training, etc. However, cyber threats provide new challenges that I believe require a different approach than that being addressed by the NERC Critical Infrastructure Protection (CIP) cyber security standards[1]. This paper will identify several key areas that are often overlooked or not properly addressed that utilities, regulators, insurance companies, and others can use for assessing if utility cyber security programs are adequate to secure electric utility assets from intentional or unintentional cyber threats. These areas have either potentially affected, or actually caused, control system cyber security incidents. Consequently, adequately addressing each of these areas is critical to securing electric industry operational assets.

Background

There are a number of organizations and standards for establishing a cyber security program. These include the NIST Federal Information Security Management Act (FISMA)[2] and associated controls document – NIST Special Publication (SP) 800-53A[3] and ISO 17799[4] and 27001[5]. These documents do not provide exclusions for assets such as telecom.

The NERC CIPs have now been ratified by FERC (with modifications). So why is there a question of prudency? Unlike IT standards, the NERC CIPs include specific exclusions (distribution, non-routable protocols, telecom, and nuclear plants). The NERC CIPs also specify the use of a risk assessment methodology to determine critical assets and critical cyber assets, but provide no details. These explicit and ill-defined requirements have enabled utilities to minimize the number of assets to address; in some cases ZERO critical cyber assets. IT assets governed by SP800-53 or ISO-27001 are actually more secure than our most critical operational assets such as substations and power plants. How can that be? Consequently, this paper addresses key areas that may be overlooked in establishing and/or maintaining a prudent cyber security program. Many of these issues were identified in the FERC Technical Staff Assessment of the NERC CIPs[6] and the FERC Notice of Proposed Rulemaking (NOPR) RM06-22[7].

There are two caveats that should be noted. There are no metrics for performing a control system cyber security audit. The Industrial Control System version of NIST SP800-53[8] provides arguably the best metrics. Secondly, many control systems have no logging for control system cyber security. Consequently, it may not be possible to identify control system cyber incidents or their causes.

Based on experience and actual control system cyber security incidents, a prudent control system cyber security program should include the following:

Control System-Specific Cyber Security Policies and Procedures.

The biggest payback in electric utility (and other industry) control system security programs is implementing comprehensive control system cyber security policies and procedures. In order to make sure they are taken seriously, the adherence to these policies and procedures should be one of the performance goals of senior management (per the NERC CIPs). Almost all utilities have cyber security policies, but many are based on traditional IT policies and technologies. This can be a problem for the control system's environment. While some components of an IT security program can be applied to control systems, many of these policies are not relevant to the real time control system environment and inappropriate when addressing legacy field devices. For example, there have been numerous cases where inappropriately applying traditional IT security technologies such as certificates, block encryption, or even anti-virus have impacted or completely obstructed control system operation.

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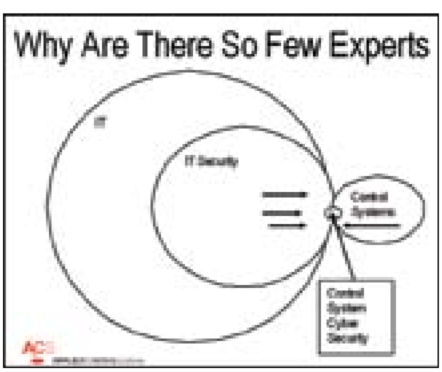
[1] NERC Cyber Security Standards, http://www.nerc.com/~filez/StandardsStandards/Cyber-Security-Permanent.html
[2] http://csrc.nist.gov/groups/SMA/fisma/index.html
[3] NIST Special Publication 800-53A, Guide for Assessing the Security Controls in Federal Information Systems Building Effective Security Assessment Plans, December 2007, http://csrc.nist.gov/publications/drafts/800-53A/draft-SP800-53A-fpd-sz.pdf
[4] http://17799.denialinfo.com/
[5] http://www.27001-online.com/
[6] Federal Energy Regulatory Commission Staff Preliminary Assessment of the North American Electric Reliability Corporation's Proposed Mandatory Reliability Standards on Critical Infrastructure Protection, December 11, 2006 RM06-22-000.
[7] Federal Energy Regulatory Commission Docket RM06-22, http://www.ferc.gov/docs-filing/elibrary.asp
[8] Recommended Security Controls for Federal Information Systems, NIST Special Publication 800-53 Revision 2, December 2007, http://csrc.nist.gov/publications/nistpubs/800-53-Rev2/sp800-53-rev2-final.pdf

NIST testing has demonstrated that updating antivirus definition files can cause a 2-6 minute denial of service on legacy control system processors. Traditional IT security testing can be even more problematic for legacy systems. Many legacy control systems have been designed without a complete IP communication stack. Scanning legacy control system devices and/or networks utilizing traditional IP scanning tools can lead to broadcast storms as the scanning tool attempts to locate devices that cannot adequately respond. A broadcast storm is a state in which a message that has been broadcast across a network results in even more responses, and each response results in still more responses in a snowball effect. A severe broadcast storm can block all other network traffic, resulting in a network meltdown[9]. There have been several actual control system cases where scanning control system networks and/or devices resulted in broadcast storms significantly impacting control system performance. In at least one case, scanning resulted in damage to control system equipment requiring replacement before the equipment (in this case variable speed drives) could be reused. Consequently, it cannot be stressed enough how dangerous scanning can be to legacy systems if not performed knowledgeably and with caution. Scanning is not the only issue. A recent case involved the tripping of a 50 MW generator because of inappropriate policies. Inappropriate architecture has also led to cyber incidents including the shutdown of a large nuclear power plant.



Another common problem is security of dial-up modems. Many users feel that all modems have been identified and disconnected when not needed. When visiting users (not just utilities), I have yet to meet a user that hasn't told me they know where all of their modems are and they are disconnected when not in use. Conversely, after detailed discussions and walk-downs, I have yet to find a user that hasn't found at least one modem they didn't know they had or at least one modem that was connected they thought was disconnected. Any modem that is not secured is a cyber security vulnerability. The recent Idaho National Laboratory (INL) demonstration that was shown on CNN destroyed a diesel generator by using dial-up modems[10].

Without appropriate control system policies and procedures, you cannot secure your control system assets. It is also the surest way to fail a "real" (are you really more secure?) control system audit or the quickest path to unintentional control system problems.

System integration

In the past, identifying relevant stakeholders for a SCADA or plant control system was easy: it was limited to facility and corporate operations and engineering. Today, it is much more complex and tomorrow will be even more so. Part of what makes control systems more productive is also what makes them more insecure – system integration. More and more organizations are finding their most valuable and useful data is the *real-time* control system data. This is leading to many internal organizations establishing, or wanting to establish, connections to a SCADA, plant control system, programmable logic controller, or control system database without the corporate or facility operations and engineering organizations even being aware. Additionally, productivity can be enhanced by integrating control systems such as SCADA with non-control systems such as customer management or geographic mapping programs. Depending on how the networks are configured, this can, and has, resulted in actual cyber incidents including the only case I know of where a SCADA system was targeted and incapacitated.

Performing vulnerability assessment to prudently identify all electronic connections

Utility organizations are beginning the process of assessing cyber vulnerabilities of their control systems to meet the NERC CIPs. The creation and execution of these assessments needs to be done carefully as there are several significant and frequently conflicting issues at play. The first is scope. NERC is focused on grid reliability. There are many specific scope exclusions in CIP-002 such as telecom, market functions, distribution, and non-routable protocols. Many utilities have excluded these systems in their vulnerability assessments since they have been excluded by the NERC CIP. Many of these excluded systems are cyber vulnerable and directly communicate with systems that are in the CIP-002 scope. Consequently, it is not possible to comprehensively identify the cyber vulnerabilities that can impact these critical cyber assets. Implicitly, there is another exception – small facilities. The NERC CIP implies that traditional reliability criteria can be followed in defining what equipment need be identified and addressed as critical assets which implies large facilities. This makes sense from NERC's traditional reliability perspective. Since most utilities have provided redundancy in substations, power plants, and sometimes even control centers, many utilities have identified very few critical cyber assets. In reality, the NERC CIPs are a cyber standard, not a traditional reliability standard. From a cyber perspective, it is the connectivity that determines criticality, not the size. The analogy is 9/11. The terrorist that hijacked the plane in Boston did not originate in Boston. Rather, they boarded in a smaller airport with no security. The same philosophy occurs here. A very small facility that is connected to a larger facility can impact the larger facility or any other facility to which it is interconnected. A common control system network that can shutdown all facilities, be they power plants or substations, can have an impact on the grid.

From a cyber security issue, it is irrelevant how large or critical the system is to normal reliability considerations. From a cyber perspective, what matters is if the equipment is electronically *connected*.

[9] http://www.webopedia.com/TERM/B/broadcast_storm.html
[10] Sources: Staged cyber attack reveals vulnerability in power grid, September 26, 2007, http://www.cnn.com/2007/US/09/26/power.at.risk/index.html

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Even the smallest facility, if electronically connected to a control center, can be a pathway to compromise the control center. Conversely, a very large facility that is critical for reliability considerations but has no electronic connections is irrelevant from a cyber perspective. When addressing cyber security, it is not the size of the device or facility, but the *connections* that matter.

Another issue that must be considered is the exclusion of telecom. One of the most probable causes or paths for cyber intrusions are the inherent vulnerabilities within the telecommunications environment. The NERC Electric Sector ISAC issued an advisory on the Slammer worm that occurred in January 2003 affected a frame relay system[11]. The final report of the Northeast Outage also identified wireless and wireline communications[12] even though the NERC CIPs excluded them. It has been demonstrated by one of the National Laboratories that 900 MZ spread spectrum, frequency hopping radios can be hacked. These radio systems provide the critical communications within the substation and provide input directly to SCADA. Compromise of these radio systems can lead to compromise of the devices within the substation. If the current exclusions in the NERC CIP are followed, these devices using non-routable protocols will be excluded from the assessment process which represents the vast majority of utility communications. This doesn't make sense. It should be mentioned that small systems, utility telecom systems, and non-routable protocols have experienced cyber incidents.

The distribution systems are excluded from NERC cyber assessments. However, because they often have undergone the most upgrades, it is the distribution systems that have now become arguably the most cyber vulnerable part of the T&D system. As distribution systems are electronically *connected* with transmission systems, they should not be ignored. There have been several electric distribution cyber incidents that could, or have, resulted in cascading outages. The market function of an EMS system receives data from insecure meters and also electronically *connects* with SCADA. As with distribution, the market functions are often excluded by the NERC CIP. These vulnerabilities could lead to very significant economic impacts if meter or billing data is compromised. Additionally, there have been several incidents where nuclear plants have had cyber incidents. Losing large central station nuclear plants does have a significant impact on grid reliability.

Therefore, it should be evident that by excluding systems from NERC CIP programs, it is not possible to identify all of the critical cyber assets much less the vulnerabilities that can impact critical cyber assets. Remember: It's all about the *connections* where the real cyber vulnerability exists.

Perform risk assessments for business perspectives

Cyber risk needs to be addressed for grid reliability to meet NERC CIPs requirements. However, cyber risk also affects systems that can significantly affect the business, but not necessarily affect grid reliability. Many systems that are critical to the economic health of the utility may not be critical to grid operations and are consequently excluded from the NERC CIPs. Facilities such as small power plants, low to medium voltage distribution substations, and automated metering infrastructure are examples of facilities and systems that are "business critical", but not "grid critical". There is a significant potential liability to a company for ignoring cyber risks to the business even though these systems are excluded by NERC CIPs.

Interconnections and interdependencies

The last issue is possible the most subtle, but certainly not the least important. That is the impact of interconnections between transmission systems. Electric utilities often share equipment such as RTU's. Utilities also interconnect with one another. There is an old saying in the cyber community that you are only as secure as your weakest link. In this case, your weakest link could be your neighbor. How this is addressed impacts not only you, but also your interconnection partner. These interconnections need to be addressed comprehensively. This issue becomes even more problematic when one of the interconnections is with a federal power agency such as TVA or BPA. Federal power agencies MUST meet NIST SP800-53 which is more comprehensive than the NERC CIPs. Consequently, any non-federal utility connecting to a federal power agency becomes a weak link. Why should a federal power agency be held to a higher standard?

Summary

The issues addressed in the NERC CIPs have done the utility industry a great service by beginning the process of requiring cyber security to be specifically addressed. However, it has done so in a limited manner. Many of the identified limitations have already led to cyber events. In order to minimize risk to the utility infrastructure and business operations, it is incumbent on the utility to utilize due care and diligence in establishing and maintaining their cyber security programs. Cyber issues can materially affect the utility industry's bottom line from a positive direction (improving system reliability and availability) or from a negative direction (cyber impacts). The positive direction takes a comprehensive program beyond "just meeting the NERC CIP requirements". The negative direction can occur because the program was not sufficiently comprehensive and can lead to punitive damages as suggested by NERC. The choice is up to you. ■

About the Author

Joe Weiss *is an industry expert on control systems and electronic security of control systems, with more than 30 years of experience in the energy industry. He is a member of numerous organizations including the NERC CSSWG, IEEE, ISA, IEC, and CIGRE.*

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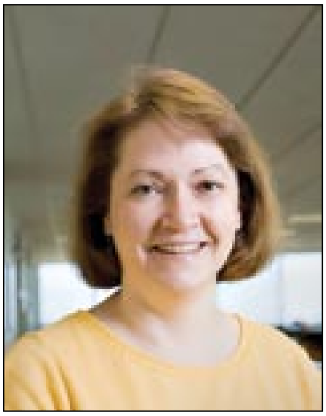
[11] SQL Slammer Worm Lessons Learned for Consideration by the Electricity Sector, June 20, 2003, http://www.esisac.com/publicdocs/SQL_Slammer_2003.pdf.
[12] Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, April 2004, https://reports.energy.gov/B-F-Web-Part1.pdf



Data Refresh: Breathing New Life into a GIS Database

By Ruth Craven and Dr. Will Shepard,
Enspiria Solutions

Data Refresh: Breathing New Life into a GIS Database

Geographic Information Systems (GIS), a component of what is known as "spatial technology", has origins in simpler systems such as Computer Aided Design (CAD) and Automated Mapping/Facility Management (AM/FM) systems. However, in order to fully reap the benefits of spatial technology, many utilities and other organizations find it necessary to augment and increase the quality of their existing data; in other words, to refresh their GIS data.

A History of Spatial Data Acquisition

In its infancy, from 1950 to the early 1970's, spatial technology addressed cartographic applications such as mapping and charting of land, water and demographic data. By the late 1970's and early 1980's, spatial technology had begun to mature, and utility companies were amongst the first organizations to adopt CAD or AM/FM. At the time, these systems were at the leading, and often bleeding, edge in the utility industry. Primary applications included mapping, facility inventory, map-book production and sometimes construction print production. In these early systems, spatial technology was usually a departmental solution, addressing only a limited set of needs. Spatial technology matured in the late 1980's and early 1990's, fueled by the proliferation of personal computers, client/server technology and scalable architecture. The late 1990's saw the growth of more sophisticated spatial applications, and the technology became known as "GIS" to emphasize the geographic focus, and saw the promotion of increased enterprise use.

Utilities that adopted spatial technology in the early years were challenged by the data resources they had – or didn't have – to populate the system:

- **Existing maps**: How accurate were the maps? Were the maps maintained? What was the map coverage?
- **Facilities data sources**: What data was available? Was it available digitally? Was the data consistent across the enterprise? How complete was the available data?
- **Land data**: Was commercial land data available?

AM/FM systems were usually populated by digitizing source paper maps, performing field inventories and incorporating other digital data sources, such as transformer databases. Not unlike today, the quality of the resulting AM/FM data was directly proportional to the quality and completeness of the source data or field inventory, the ability to associate various facilities data and the scope of the data conversion. For example, attribution from source maps often could not be related to nearby facilities and hence was converted as annotation, instead of attribution. In addition, connectivity was not a priority, since it was not necessary for map production.

Given that the value of spatial data for applications was often not understood during initial data conversions, current GIS data holdings often do not support advanced use of the data. If the scope of the facilities attribute population encompassed only what was needed to support mapping and facilities management, then the data may not have included all of the facilities, attribution and connectivity required for advanced applications such as outage management, asset investment, gas distribution integrity, advanced metering, dashboard applications or integration with an enterprise asset repository.

Refreshing GIS Data

Today, GIS is a mainstream enterprise system that is recognized as an enabling technology for other operational and energy delivery systems. Utilities recognize the enterprise value of spatial data and are eager for advanced applications and integrations. However, lacking data or poor quality from initial conversion efforts will hamper moving forward with these initiatives. Successful implementation of these initiatives will require refreshing GIS data through additional collection and reconciliation of existing data problems. Advanced applications and integrations, with their supplemental data requirements, include:

- GIS often owns the relationship between a customer's premise and the feeding transformer. Applications such as outage management systems (OMS), transformer load management (TLM), and network analysis require the premise-transformer relationship, circuit connectivity and integrated customer data.
- Applications receiving network/circuit connectivity from GIS require high data quality. For example, OMS requires that the nominal state of the network accurately reflects the field conditions. If it doesn't, outage projections and statistics will not be useful.

- Analysis tools available with graphic work design (GWD) products require location accuracy in order to provide useful results, such as accurate pole locations for guy placement analysis.
- Along with circuit connectivity, engineering analysis programs require valid stock code attribution, for example, device and conductor characteristics.
- Mobile applications such as service calls and trouble restoration utilizing spatial data are more successfully implemented when there are unique location identifiers, unique device identifiers, and accurate positional data.
- Transmission and distribution siting requires additional land data layers in order to do multiple realistic path sitings for the approval process.

Refresh activities to acquire this data include capturing additional facilities through field collection (for example, facilities that were not originally included in the inventory because they were not needed for maps, but that are now important for applications), updating of currently populated but dated attribute values, populating attribution from floating annotation and improving the positional and topological accuracy of facilities.

A data refresh initiative is not a simple effort. However, the results of this undertaking can enable successful implementation of advanced GIS applications, facilitate benefits realization of such applications and provide additional ROI from the GIS. Complexities and considerations of undertaking a data refresh initiative are not unlike initial data conversion or migration. **(See sidebar)**

The good news is these complexities can be resolved with a thoughtful, organized approach. A data refresh effort requires thorough planning and a project approach to allow the enterprise to reap the benefits of improved spatial data and to recover data refresh costs. **(See sidebar)**

Advanced Applications of Spatial Data

GIS implementation experts delineate different phases of implementation. These phases define increasingly sophisticated spatial data usage, and the expansion of advanced applications and integrations. Each phase allows the utility to realize increasing benefits and efficiencies in the energy delivery process (refer to Figure 1 and Table 1). A phase 1 GIS implementation is comprised of the standalone GIS along with other similarly standalone enterprise systems, such as work management systems (WMS), inspection and maintenance systems (I&M) and computerized maintenance management systems (CMMS).

Depending on the scope of a standalone GIS implementation as well the original data conversion scope and current data quality, GIS data may not support phase 2 and higher phase implementations. If current data cannot support the higher phase implementations, a data refresh initiative is required before the GIS can be leveraged to obtain additional ROI through advanced applications and integration with other systems.

Phase 2 implementations involve the integration of standalone systems. From the perspective of spatial data, GIS is integrated with other enterprise systems such as WMS and CMMS, as well as graphic work design (GWD), outage management (OMS), customer information (CIS) and distribution planning (DPS).

A phase 3 implementation brings together data marts owned by the various energy delivery systems for asset optimization. Distributed data is integrated in order to optimize capital expenditures and maintenance expenses. GIS continues to be an enabling technology in phase 3 implementations, such as OMS, interruption reliability reporting, enterprise asset management, and network planning. In the case of OMS, outage causes can be visualized geographically and analyzed using equipment maintenance and characteristics, and failure history. Interruption reliability reporting utilizes data from the GIS, OMS and CMMS. For enterprise asset management, CMMS obtains assets and spatial references (such as GPS coordinates, routing or survey grids) from the GIS. Finally, for network planning, data from GIS and CIS, together with historical performance of assets, can be used to optimize load and reliability.

DATA REFRESH COMPLEXITIES AND CONSIDERATIONS

- For what applications and integrations is the data refresh targeted?
- What positional accuracy is required for targeted applications, and beyond? How will existing coordinate data and new GPS position data be reconciled or coexist?
- How will the data refresh be funded?
- Should a widespread inventory be conducted? Should the data be collected along side normal field work? Can the data be collected in small areas as part of summer internships? Or all of the above?
- How will the data be maintained going forward?
- Can in-house labor perform the data refresh activities? Is contract labor needed? Or both?
- What data can be collected? For example, some conductor characteristics may not be discernible.
- Will existing GIS data be extracted or will the inventory return 'from scratch' data? If extracted, what is the mechanism to extract the GIS data?
- What is the mechanism for incorporating data returned back into the production GIS data mart?
- What data reconciliation efforts will need to be performed, i.e. meshing the new data with existing data? What software and effort will be needed?
- Will normal day-to-day posting of as-built data be frozen or will data coming back from a field have to be 'reconciled' with data posted since the original data was extracted from the GIS?

Phase 4 integration combines real-time field automation with systems and repositories that house and apply spatial data. Examples of real-time systems include substation automation (SA), distribution automation (DA), advanced metering infrastructure (AMI) and meter data management systems (MDMS). Spatial facilities data, integrated with customer data, can be used to justify and plan AMI and MDMS implementations. In addition, AMI/MDMS can update the GIS when a meter has been installed on the network and notify OMS of a service outage.

These phases of implementation are not successive; they do not require that a utility complete a lower phase of implementation before elements of higher phases. However, all phases of implementation benefit from (and to a certain degree require) a foundation of accurate and complete spatial data. If higher phase implementations are built on a foundation of poor data quality, then their success is at risk. All implementations, irrespective of phase, should evaluate current data quality as part of project planning. Implementation of advanced applications may require further data collection and improved data maintenance strategies.

Summary

For some utilities, the current GIS data holdings may not be good enough to support advanced GIS applications and integrations. This occurs because advanced functions were not foreseen during initial data collection, either because data was not available, or because the data have not been maintained in the GIS. The good news is that refresh initiatives can update this data. While this is a significant undertaking, the benefits gained from strategic, enterprise applications typically outweigh the costs involved. Data refresh can breathe new life into an old GIS database.

Sources

The following sources were used in the development of this article:

- Milestones of GIS, the Geospatial Resource Portal *(http://www.gisdevelopment.net/history/1950-1960.htm)*
- Integrated Delivery Framework: An Integration Tool for Utilities, Presented at ESRI Electric and Gas Users Group 2006 by Tom Helmer, Enspiria Solutions, Inc

Figure 1. Evolution of GIS

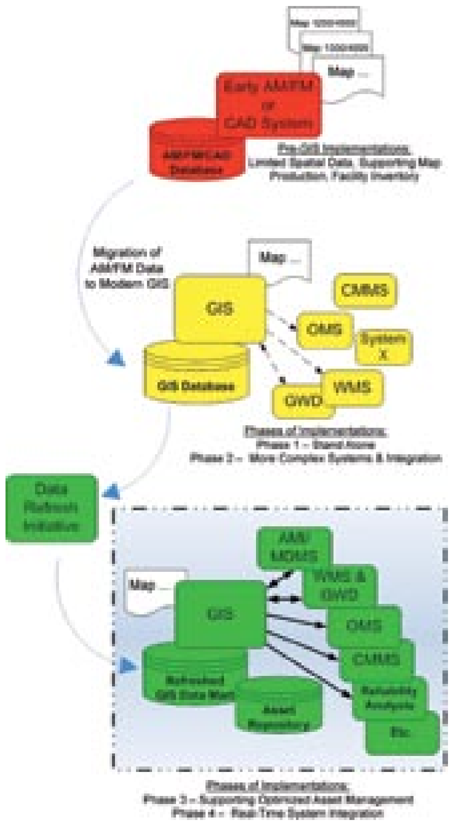


Table 1. Phases of Systems Implementation and Integration

Phase	Phase Activities	Key Features	Benefits
1	Stand-alone deployments of energy delivery systems: GIS, CIS, GWD, WMS, CMMS, MWM, SCADA and DPS.	Data redundancy from data maintained in multiple places results in data conflicts.	Work becomes automated.
2	Integration of systems for workforce optimization, e.g.: CIS → GIS GIS → OMS GIS ↔ GWD/WMS GIS ↔ CMMS	Integration is aided by modern enterprise integration infrastructures. GIS is used to correlate information from disparate systems.	Work processes and data maintenance costs are optimized.
3	Integration of individual system data marts for asset optimization.	GIS is a key enabler for the further integration of enterprise data, resulting in implementation of an enterprise data repository.	Asset information (e.g. characteristics, performance and location) is used to analyze and optimize capital expenditures and maintenance activities.
4	Integration of near real-time field automation.	Information from real-time systems such as AMI, MDMS, SA, & DA are leveraged by operational and engineering systems.	Field information (e.g. service outages, feeder outages, device outages, loads) is used in near real-time by the enterprise.

DATA REFRESH PLANNING AND MANAGEMENT ACTIVITIES

- Perform a strategic implementation plan and data audit to target applications and integrations that will benefit from new or improved data and to target data efforts that will offer the biggest-bang-for-the-buck.
- Explore cross-organizational funding and sponsorship during strategic planning of the data refresh initiative.
- Design and implement business processes to enable ongoing data maintenance; without this, new data will become stale. Ultimately, the organizational culture must be changed such that data quality is everyone's job.
- Pursue qualified vendors if contracted labor is to be used. While the techniques for data population have not changed drastically since early AM/FM implementations, data conversion and migration resources are now well established and experienced resources are available. Supplemental digital data sources are also more readily available.
- Keep in mind that the more 'natural' data exchange is between the GIS and the collection tools, the easier data import/export methodologies will be.
- Include a pilot phase in the data refresh initiative, including back-end processes necessary to bring refreshed data back into the production system and to reconcile it with existing data.

About the Authors

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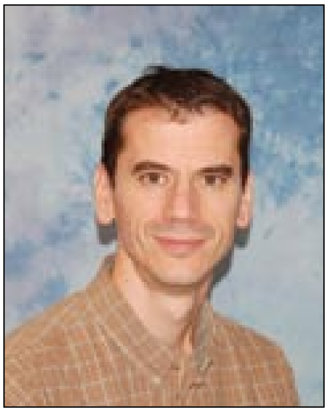

Making Substations More Intelligent by Design

PART TWO: Bringing It All Together at a Northeast Utility

By Craig M. Preuss, Engineering Manager-Utility Automation, Black & Veatch Corporation

Building on part 1 of this article in the previous issue, this second installment illustrates the issues and impacts of implementing substation integration in harmony with the utility's organization and operations using a standards-based approach. The engineering process implemented by Black & Veatch at a Northeastern U.S. utility is presented here in case study fashion. This project began in 2005 with the addition of a new substation.

The utility wanted to move their substation design from a mix of electromechanical relays and other IEDs to an integrated substation that supports automation. However, they were not starting with a blank sheet of paper. They were already extending their corporate WAN to their substations, so they knew they wanted Ethernet; but how do you install Ethernet in substations? They knew what microprocessor relays they wanted, but what protocol was the best choice of the three supported protocols (DNP3, Modbus, and IEC 61850)?

Recognizing the need from previous experience, the utility began with substation integration training to introduce personnel from across the enterprise to the equipment, concepts and issues, reasons, costs, risks, benefits, and process of substation integration. Once the initial training was completed, functional requirements for performance were defined as outlined in the first article, and the process was under way.

Input and Outputs

Substation inputs and outputs (I/O) include measurements, status, and control. By defining an I/O scheme that shows the substation data sources (See Figure 1), several underlying issues were uncovered and resolved.

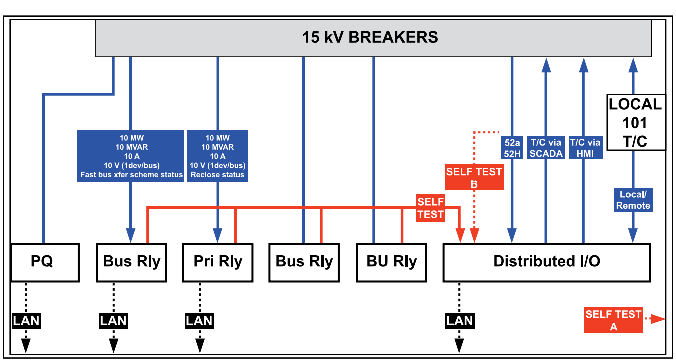

Figure 1 – Example I/O Scheme for 15 kV Breakers

On the distribution side, metering data from relays was considered accurate enough. Revenue meters were already required on two of three transmission lines and both transformers. For the remaining transmission line, it was discovered that metering values from the primary relay were accurate enough. While metering values could have been obtained from primary and backup devices, the utility decided that multiple sources added unnecessary complexity to system design and operation.

Besides standard metering quantities, other examples of analog quantities gathered from other substation IEDs are tap position, battery DC voltage, control house temperature, transformer dissolved hydrogen level, and transformer winding temperature.

For wiring the approximately 270 hard-wired status points, brief consideration was given to wiring them to relays. Significant concern was raised because many status points are not associated with relays and the status of equipment still in service would be lost when an unassociated relay was taken out of service. By hardwiring breaker status and other status points to an IED dedicated to that purpose, the source of status and controls is readily known and easily isolated. For these reasons, a distributed I/O device was selected for status inputs.

Initial discussions surrounding controls had the SCADA controls assigned to the primary relays and local HMI controls assigned to the backup relay. In addition, the utility wanted a manual way to perform controls outside of the relays and to also manually disable controls. Performing controls through relays resulted in the difficult association of some control points with relays and the loss of control when a relay is out of service. By using dedicated distributed I/O, the utility was able to directly trip the breaker without the use of interposing relays, but careful consideration of contact output ratings was required (See Figure 2).

VENDOR	DESCRIPTION
1	10A at 30 Vdc,½A at 125Vdc
2	Make: 30 A @ 250 Vdc per IEEE C37.90 Continuous Carry: 6 A @ 70°C; 4 A @ 85°C Break:24 V 0.75 A;48 V 0.50 A;125 V 0.30 A
3	Heavy duty protective relay-grade 10A for direct connection to circuit breaker trip coils

Figure 2 – Comparison of Distributed I/O Control Output Ratings

Protection and Time Synchronization

IEC 61850 was viewed by the utility as important for the future, but not required for immediate implementation. Although it was decided that protection functions would continue to be accomplished through traditional hard-wiring to relays initially, it was also decided that a network architecture capable of easy migration to IEC 61850 in the future was required.

Time synchronization was also considered important. IEDs are synchronized using the most accurate method supported by each IED: IRIG-B, NTP/SNTP, and DNP. All three time synchronization methods were implemented in the system, depending upon how each IED vendor supports time synchronization. Some IEDs did not support any of these standards, however.

IRIG-B calculations were performed during the initial design to ensure proper signal levels. It was discovered that the load from the backup relays and the distributed I/O devices required the IRIG-B network to be split up, and a high-drive output was needed on the satellite clock. The high-drive output requirement made it impossible, however, to include a timeserver on the satellite clock.

The substation computer was connected to IRIG-B and configured as a network timeserver that is ± 250 milliseconds, relative to the IRIG-B source. All data received in the HMI on the substation computer is either time stamped at the IEDs or at the data concentrator to ± 1 millisecond accuracy.

Bringing IRIG-B to the substation yard using copper cables impacts performance and may not be possible because the copper cable runs are too long for reliable operation. Distributed I/O devices located in the substation yard wer e connected using a fiber optic port achieving much better isolation and eliminating the distance constraints of copper cables. The same fiber optic cable used for the LAN connection to the IEDs in the substation yard was also used for distributing IRIG-B to the switchyard.

Programmed Logic and Ancillary Services

Programmed logic is the basis for substation automation. Supporting system-wide programmed logic functionality requires a high-speed peer-to-peer communication network. While IEC 61850 supports this requirement using high-speed messages with guaranteed performance requirements, it is also possible to use DNP3 over Ethernet for non-protective functions.

This is accomplished by IEDs broadcasting data to multiple masters or multiple masters polling the same slaves. In this application, this type of DNP3 functionality was a differentiator in the selection of distributed I/O devices and the RTU/data concentrator. How programmed logic is implemented in an IED can also vary. While most data concentrator vendors support an embedded IEC 61131-3 PLC engine, others only support a text-based or object-based programming language.

IED Selection

IED selection is always a challenging and time-consuming process because there are many IEDs available with various issues impacting the final selection. As with many utilities, this utility had already selected most of the IEDs before system design even began. Most importantly, they did not want any risk of "vaporware" in unproven products.

The utility was planning on using their standard SCADA RTU, but significant performance drawbacks were identified with this RTU related to the integrated system. This resulted in considering other RTUs and data concentrators from various suppliers. A data concentrator was ultimately selected based on how well the IED met the evaluation criteria.

Because a traditional RTU was not provided and the I/O capability of the relays was not being used, a distributed I/O device was required in the design. A distributed I/O device was selected based upon superior flexibility. However, a media converter was required for the Ethernet port to make the device fully compatible with the broader design approach.

The utility initially wanted to use their SCADA master software in the substation as the HMI. One reason was that the utility wanted the tags placed at either end replicated at the other end. After some detailed technical review with the vendor, the utility was not able to use the existing SCADA master software as the substation HMI. Thus, an evaluation of several HMI packages from various industries was undertaken to find a suitable alternative. Software from a well-established source was eventually selected that offered a number of significant performance advantages.

Substation Computer

The utility knew that they wanted a substation-hardened computer that met IEEE Standard 1613. This was a contributing factor to the SCADA master HMI not being used in the substation because of memory and operating system requirements. One useful feature was that the substation computer would easily accept an IRIG-B input and could act as an NTP/SNTP time-server.

Security

Like many utilities, this utility needed to address NERC CIP (Critical Infrastructure Protection) requirements that went beyond the new substation but were not addressed by this project. Even so, the physical perimeter is monitored. Cyber security issues are addressed by providing substation LAN equipment that includes features that help address NERC CIP requirements and implement best practices that provide a "defense-in-depth." The general approach was to physically separate the substation network from the corporate network. The substation data concentrator could also be used for access control to the substation IEDs and monitoring and logging all IED connections.

Architecture Selection

The architecture selection was based on Ethernet for four primary reasons. First, the utility had already extended their private corporate WAN and SCADA WAN to the substations, and they wanted to better utilize these networks. Second, several Ethernet-based relays were installed previously, and the utility wanted to continue using them due to their ease of use and network support. Third, the client wanted more than just SCADA data out of their investment in IEDs, including remote access and non-operational data. All of this data and functionality has value, but it requires a medium that can support significant bandwidth requirements and multiple simultaneous connections. Finally, a system architecture that could easily support IEC 61850 was desired.

While some selected IEDs did not support Ethernet, the decision was made to preserve the architecture so that serial devices were connected to substation hardened serial device servers. This worked well because the serial devices were usually located near each other.

Redundancy was not selected because the substation LAN is not initially supporting protection functions and IEEE 1613 compliant switches and routers are used along with fiber optic cables. Issues with redundant LANs include the increased cost for a LAN that is almost completely isolated inside the control house and segmenting the architecture since some IEDs do not support redundant LANs.

Protocol Selection

There was a strong desire to use DNP3 in the substation. IEC 61850 was discussed, but it was decided that using IEC 61850 might be too much to take on at the present time. In addition, the only devices that would have supported IEC 61850 directly were the relays, data concentrator, and HMI. By contrast, the one protocol almost all selected IEDs supported was DNP3.

Performance

System availability was addressed by using substation hardened equipment in all aspects of system design. All Ethernet equipment meets IEEE 1613, including the substation computer. Any IEDs that did not meet IEEE 1613 (e.g., meters, distributed I/O) were connected to a media converter. In addition, fiber optic cables are used to completely isolate the system cables from any interference. The only equipment not meeting IEEE 1613 requirements was the monitor for the substation computer, which was isolated behind a DC-DC converter designed to meet IEEE C37.90.

System changeability includes ease of expansion, provision of spare capacity, ease of replacement, and ease of maintenance. The system architecture was based on Ethernet and is inherently modular and easily scalable for expansion. By using distributed I/O, spare capacity was easily provided and can be easily added, although there is already a rather large upper limit in the number of I/O points and devices the data concentrator can effectively handle.

Because of the modular nature of the system, replacement of portions of the system can be accomplished without removing the whole system from service. System maintenance considerations included the ability to change operational parameters as well as the configuration. With a modular system being supported by multiple vendors, changes to some IEDs are easier than others, depending upon the evaluation criteria. Generally speaking, however, all selected devices support good user interfaces that are easy to work with to implement system changes.

Today

In early 2007, the conceptual design was finished and detailed design was nearing completion. This was followed by a period of validation, during which the system components were programmed and tested in a laboratory setting. Today, the project is nearing completion and will be energized soon. The internal team has received approval to build an automation test center to be used for training, testing, and provide a development environment for future automation programs. Notably, this same system design process is already being applied to another new substation. ■

About the Author

__Craig Preuss__ is the Engineering Manager for Utility Automation at Black & Veatch Corporation where he is involved in virtually all facets of substation integration and automation. Craig earned his bachelor's degree in electrical engineering from Valparaiso University in Valparaiso, IN and a master's degree in power systems from the Illinois Institute of Technology and is a registered professional engineer in the states of Illinois and Washington.

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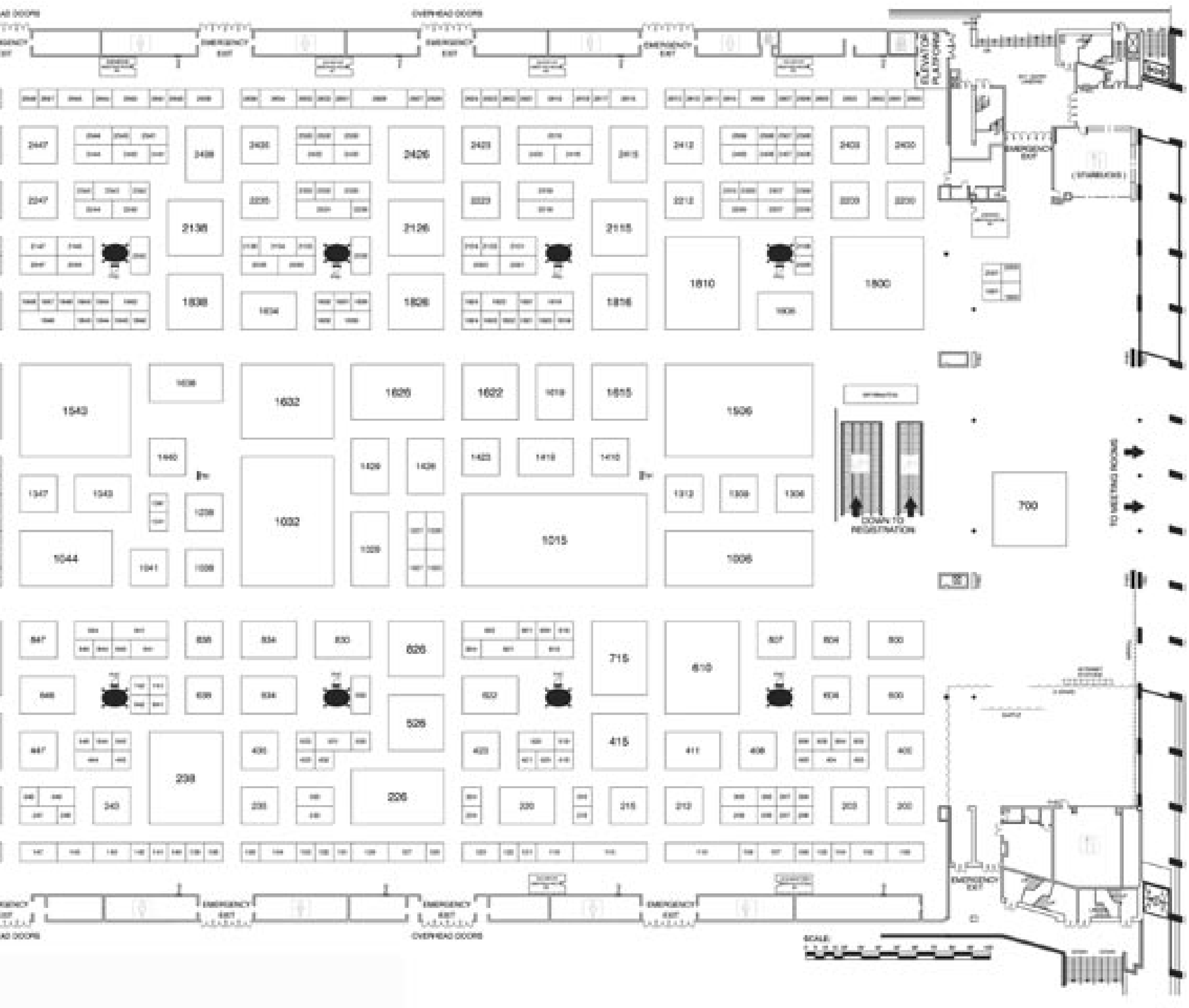


Moshe BenBassat

Getting a charge out of service optimization

By Moshe BenBassat, CEO and founder of ClickSoftware

For decades, electric utilities have invested millions of dollars in computer technology and human resources to reliably forecast future demand. Reliable forecasting affects long-term planning for infrastructure build-out, staffing, maintenance and repairs, providing executives with a telescope-like view of projected costs, revenues and potential profits.

Advanced technologies such as artificial neural networks and agent-based simulation systems gather information about myriad factors including everything from weather patterns to holidays and massive sporting events like the Super Bowl or the Olympics.

In most cases, utilities have not invested anywhere near the same resources in managing their workforces. That's going to be an increasing problem as their infrastructures and field technicians continue to age. Power lines, transformers, substations, etc. all wear down and need repair. Those technicians who have accumulated 25-30 years of hands-on knowledge are nearing retirement, and they typically take that expertise with them when they leave.

This article discusses the challenges of workforce management in the electric utilities industry, and the barriers to achieving real efficiency when using archaic systems to schedule their workforces – both internal and third-party contractors. It also discusses the technologies that automate scheduling of installation, maintenance and repair of assets while providing real-time information about technician location and job status.

This technology can also automate customer demand forecasting for short- and long-term projects down the road as well as capacity planning to ensure companies have the right staffing levels to meet the demand. Reporting tools give decision makers vital key performance indicator (KPI) information at their fingertips so they can make smart decisions. Optimizing mobile workforce management will go a long way to help utilities improve overall operational efficiency, cut costs and increase profits as they take steps toward becoming real-time service enterprises.

Complex factors weighing on mobile workforce management

Electric utilities face some of the most complex challenges of any industry when it comes to workforce management. On any given day, field technicians read, install and repair meters, respond to downed power lines or work on long-term infrastructure projects. They may work alone, in a crew, or with a team of outside contractors. Technicians can find themselves at a home, a business, or a substation for a municipality that has a contracted service guarantee.

A single workforce absence can throw entire schedules into disarray, forcing dispatchers to scramble to find additional resources with the necessary skills and experience to get jobs done on time. A shortage of field resources means electric utilities have to do whatever is necessary to complete those jobs, whether that means paying overtime, hiring outside contractors, or both.

Then there are the additional industry factors that force utilities to find ways to reduce costs and efficiencies – all ultimately affecting how they manage their workforces. Governments worldwide are increasingly mandating reduced carbon emissions, which presents significant cost, infrastructure and logistics challenges. Commercial customers increasingly demand lower prices, supply security, zero interrupts and higher network capacity while trying to reduce peak usage via demand management and better consumption plans.

The aging workforce coupled with the relatively low numbers of young field technicians joining the ranks should scare any electric utility executive. Here's why. According to the U.S. Department of Energy, as much as 50 percent of the line worker workforce could retire in the next decade. The largest percentage of the workforce population is in the 45-54-year-old age range, based on U.S. Bureau of Labor Statistics. So when those people who have accumulated three decades of expertise – including everything from remembering part numbers to efficient repair shortcuts not outlined in a manual – leave, that knowledge generally doesn't transfer to incoming technicians.

The aging infrastructure is also going to demand organized, well-anticipated planning. The more utilities can do to prepare for short- and long-term repairs and replacements, the more efficiently they will complete these projects, minimizing the risk of problems such as unplanned outages.

All of these challenges can amount to a big nightmare for utilities still using paper-based or legacy software programs to manage their workforces. Acting on stale data and hunches about where technicians are, the status of jobs, unplanned emergencies and other factors leads to a host of problems, including fewer jobs per day, longer response times and frustrated customers.

Worse still, conducting the trend analyses and demand forecasting to plan for future workforce needs becomes a series of "best guesses" that may prove costly. Trying to project substation installation staffing while ensuring you have enough technicians for other projects without comprehensive data would be like trying to predict the weather using only binoculars.

Automation at work

Electric utilities need to adopt a service optimization approach that simplifies the industry's inherent complexity. This approach automates and optimizes workforce scheduling and planning for a variety of industry-specific work types – including meter operations, maintenance, construction work, meter reading and emergencies – from a single, centralized application.

This type of service optimization enables electric utilities to better complete routine tasks and maintenance, perform long-term infrastructure work and respond to emergencies while keeping operational costs low and service at contracted levels. More importantly, critical information about where technicians are throughout the day, their job completion rate, etc. becomes available in real time. Managers, dispatchers and field crews can react more quickly to everything from unexpected delays to emergencies to reduce customer service wait times.

Automating scheduling certainly has its benefits: reduced costs; streamlined job management; better real-time visibility of operations; more productive field technicians who spend more time on site than on the road; more on-time arrivals; and faster job completion. Decision support and optimization software relies on agents that constantly "listen" to the stream of incoming information from the entire system; including new emergency jobs, jobs that take longer or shorter than planned, or a technician who is stuck in traffic. The software processes that information against a broad set of variables and business rules such as technician skill set, geographic region, tools on the truck, service level agreements etc. and determines how to keep the schedule continually optimized throughout the day and across the entire enterprise.

Electric utilities using paper-based or simplistic scheduling systems would benefit from a unified schedule that includes anything from simple short tasks to more complex projects that may span over many days require multiple resources and have several stages. Rather than having to work off of different printouts or separate applications, managers have one view of all resources in the field based on job type at any point during the day. Additionally, managers would have crew allocation and management capabilities that aggregate individual technicians into a time-phased crew that is scheduled, so they have more accurate information about which technician is where throughout the day.

Unified scheduling also encompasses managing third-party contractors. Historically, this has been a challenge in any utility industry as contractors typically work to their own schedules more than what the utility tells them. Just as disturbingly, contractors don't have the access to the complete data, maps, repair history, etc. that the internal workforce uses. Automatically scheduling the contractors and gathering real-time information about their progress is a significant step forward for electric utilities that want to stay profitable and ensure a consistent level of service.

Location-based services incorporating street-level routing (SLR) are another important time management feature set that ensures technicians take the most time-efficient routes to jobs. Online traffic updates automatically send alerts to technicians about accidents or road construction delays so they take faster alternate routes. These schedule optimization tools not only ensure on-time arrivals, they also help maintain high levels of productivity.

Other ways to keep track of technician progress include global positioning systems (GPS) and integration of mobile devices into the system. For example, not only can the system automatically send schedule changes to technicians' handheld devices or mobile phones in the field, it can also receive schedule "delay" and "jeopardy" alerts that could affect the schedule.

An electronic crystal ball

Companies have invested heavily in developing a system of interlocking technologies, business models and supervisory processes that enables them to automatically and manually balance the future supply and demand of electricity based on kilowatt hours. Utilities should draw on that expertise while incorporating service optimization techniques to balance future supply and demand of field technician expertise measured in "lineman minutes."

Reliable demand forecasting not only incorporates detailed historical data, it also enables a forecaster to integrate a host of other information – sales and marketing input, meteorological outlooks, strategic organizational decisions, anticipated outcomes of planned business events, etc. – into the forecasting process. This gives the company more of an integrated overview of future customer demand and how it fits into the overall business. Conversely, utilities can use the same information to build a knowledge database about the impacts of various business events on the expected demand. As a result, forecasts become increasingly more accurate.

Utilities should also pay close attention to accurate workforce planning based on the demand forecast data. Poor planning can lead to high costs associated with overtime, low utilization and missed service level agreements (SLAs). A good capacity plan ensures that the company has just enough resources with the right skills in a given territory at the right time to provide maximal demand coverage and resource utilization at minimal cost to the organization.

Service optimization technologies can automate gap analyses to help electric utilities identify capacity shortages or overages in a given territory at a given time for a given demand type. These systems facilitate decision-making on how best to close the gap between forecasted demand and current workforce capacity. In doing so, the application considers many factors when determining optimal staffing levels, including defining the optimal skill mix, training programs, temporary and/or permanent relocations, vacations/non-availability, subcontractor usage, overtime usage and expected demand backlog.

Effective capacity planning, along with increased training programs, can help electric utilities alleviate the impact of the aging workforce. With reliable demand forecasting and workforce planning, utilities can anticipate periods of high turnover (as experienced technicians leave the company) and schedule long-term projects before or after that period. Doing so helps power companies adapt to the change and ensure customers don't "feel" any impact.

Business intelligence

Electric utilities have no shortage of data. But that data is only valuable to them if they can quickly interpret it for more effective decision making. Reporting applications that allow managers to capture, analyze and present the data in the manner that makes sense to them and their shareholders are critical to gaining a comprehensive view of the overall business. KPIs ranging from the average number of jobs per technician per day to emergency response time averages are crucial in determining how to manage schedules and technicians.

The market is filled with complicated reporting tools that require database administrators to operate. Utility managers need mouseclick access to the information that is important to them. They also need easy drilldown capabilities to see activity based on territory, time, customer and field resources. Some reporting tools provide executive-level business monitoring tools that let decision-makers see dashboard displays of real-time critical information about costs, service levels and utilization performance in easy-to-read graphics. When a specified KPI exceeds acceptable service level thresholds, the system immediately alerts executives so they can drill down to pinpoint specific problem areas and business units. With this information, they are able to quickly take corrective actions across relevant business units in the organization.

The real-time enterprise

Electric companies still using paper-based or static, map-based legacy workforce scheduling systems should consider taking steps to becoming real-time service enterprises. Just as they've invested in ensuring a balance of kilowatt hour supply and demand, they need to invest in managing the supply and demand of their field technicians' time on the job. Automated mobile workforce management and service optimization is fast becoming a competitive advantage that lets power companies more accurately anticipate how countless variables unique to the industry will affect future projects... and the business as a whole. Adopting these strategies will help lower costs, boost technician productivity, increase profits and deliver on their promises to customers. ■

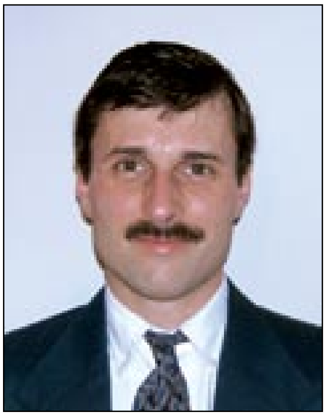
About the Author

***Dr. Moshe BenBassat** is the CEO and founder of ClickSoftware. Dr. BenBassat continues his professorial role by teaching the service industry how to better manage field workforces, reduce costs, increase revenues and keep customers happy. He launched ClickSoftware in 1997 to provide utilities, telcos and other service organizations with technology that automated their time-consuming, manual scheduling and workforce optimization processes. He realized that these companies could make field technicians more productive and be more responsive if they could better control what he calls the W6 — Who does What, Where, When and With What tools?*

BenBassat earned doctorate, master's and bachelor's degrees in mathematics and statistics from Tel Aviv University.

Providing High Speed Relay Fault Protection between Substations

By



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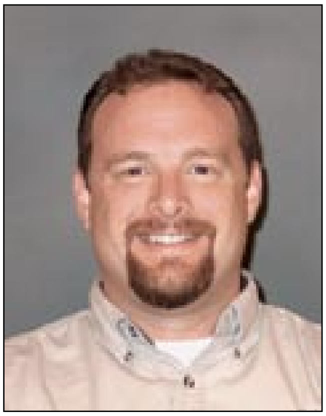

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Abstract:

Serial communications has been the mainstay for communication systems for more than a decade using RS232 and RS485 as the physical layer. However, the Ethernet juggernaut is enticing systems engineers to re-evaluate their existing approach to telemetry with the potential benefits of a bigger 'pipe'. Fortunately, familiar protocols support TCP/IP over Ethernet making the switch relatively easy for greenfield deployments. Retrofitting Ethernet and newer IEDs into existing communications systems require supporting a hybrid network of both Ethernet and serial devices. One approach to a hybrid network is serial tunnelling through serial servers as described below and includes an example illustrating the benefits of a real implementation.

Ethernet Brief History

Today Ethernet is the predominant and most popular networking technology used in office and home environments. Their use is quickly becoming popular for industrial and utility applications including substation automation networks.

Ethernet networks were not developed with the intention of being used in substations and other harsh environments. New Ethernet equipment has been designed to operate under extreme harsh environment; therefore, both industrial and utility networking experts are moving forward accepting the limitations of Ethernet networks and solving the associated problems, with the sole objective of taking advantage of the benefits provided by Ethernet.

Ethernet in Substation Environment

If Ethernet devices are used in substation automation applications, they should comply with either IEC 61850-3 or IEEE P1613 standards for EMI immunity and environmental requirements to ensure reliable operation of networking equipment in substation environments.

For applications where the Ethernet network will be involved in critical protection functions, the Ethernet switches should comply with the **Class 2** device definition given in IEEE P1613 (i.e. error free communications during the application EMI immunity type tests).

Managed Ethernet switches with advanced Layer 2 and Layer 3 features such as IEEE 802.3 Full-Duplex operation (no collisions), IEEE 802.1p Priority Queuing, IEEE 802.1Q VLAN, IEEE 802.1w Rapid Spanning Tree and IGMP Snooping / Multicast Filtering should be used to ensure real-time deterministic performance.

A variety of flexible network architectures offering different levels of performance, cost and redundancy are achievable using managed Ethernet switches.

The following are a few reasons why migrating to Ethernet is the way of the future in Substation Automation:

- Enables Peer-to-Peer Communications
- Allow for Multiple Masters
- Client – Server vs. Master – Slave
- Higher data transfer
- Higher bandwidth
- Fast Network Recovery protocols

Enabling Peer-to-Peer Communications

Peer-to-peer communication allows two or more protection and control relays to share information, enabling the potential for extremely fast system reconfiguration, enhanced protection and improved reliability. Typical applications being deployed include protection pilot schemes, relay cross-tripping, distributed source transfer schemes and bus differential protection.

As previously noted, Ethernet as a media has been mentioned a number of times and installing Ethernet-based LANs in substations is a growing trend.

Peer-to-peer protection and control systems implemented over Ethernet addresses the available bandwidth problem that can occur with peer-to-peer protocols such as GOOSE messaging, part of the UCA 2.0/IEC 61850 standards.

Some relay manufacturers have developed their own proprietary peer-to-peer communications protocol originally designed to work over serial networks with operating speeds as expected for the application.

The fact that not all relay vendors choose to follow international standards force end users to search for ways to allow the co-existence of serial and Ethernet systems in the same network, eliminating the need to build and maintain two or more separate networks.

SERIAL TO ETHERNET TECHNOLOGIES

Overview

Ethernet infrastructure is usually available, or can be easily implemented. Buildings tend to have existing Ethernet networks. PLC and RTU manufacturers are starting to develop Ethernet add-ons to network their products, at a premium cost for this functionality.
Serial servers are a cost effective solution that, utilizing Serial-to-Ethernet technology, allow integrating serial devices that are not Ethernet capable together with Ethernet capable devices on the same local area network (LAN).

A transparent serial tunnel is created over Ethernet without changing much of the existing setup. The ability to create Virtual COM Ports eliminates the need to upgrade the existing hardware with network add-on modules.

The main benefits of having access to the substation LAN are:

- High-speed peer-to-peer communications between IEDs
- Reduced inter-IED wiring
- Coexisting multiple protocols on the same physical network
- Fast Network Recovery utilizing protection protocols like eRSTP for more reliability should a link failure occurs.

Over all result is a protected network architecture that provides reliability and high availability with all components integrated on the same Ethernet backbone network at lower cost.

RaW Socket TCP/IP

The basic idea behind Raw Socket is extending a serial network behind serial communications limitations by encapsulating serial data in IP datagrams that can travel over a standard IP network that spans across cities, countries, and some times continents.

Socket mode of operation provides a way of directly accessing device servers across a TCP/IP network without first having to install a driver. Sockets are standard APIs (Application Programming Interfaces) used to access network devices over a TCP/IP network. Two socket API standards are in common use. The original standard, known simply as 'Sockets', was developed for the Unix/Linux environment. The Windows alternative is 'Win Sock'. Although there are fundamental differences between these two standards, most of the API function calls from either system have the same structure and consequently, socket based network control programs are portable across almost all system platforms.

Two appropriately configured device servers can work in unison to form a serial tunnel. The serial tunnel operates by encapsulating serial data in a TCP/IP packet, which is then transported across an Ethernet network. This operation mode allows transparent connection of all serial devices and is also a good way to network DOS based PCs or PDAs, or two serial IEDs connected in a peer-to-peer mode using IEC61850 GOOSE messages or SEL Mirrored Bits®. Because the connection is truly transparent, proprietary protocols can be transmitted.

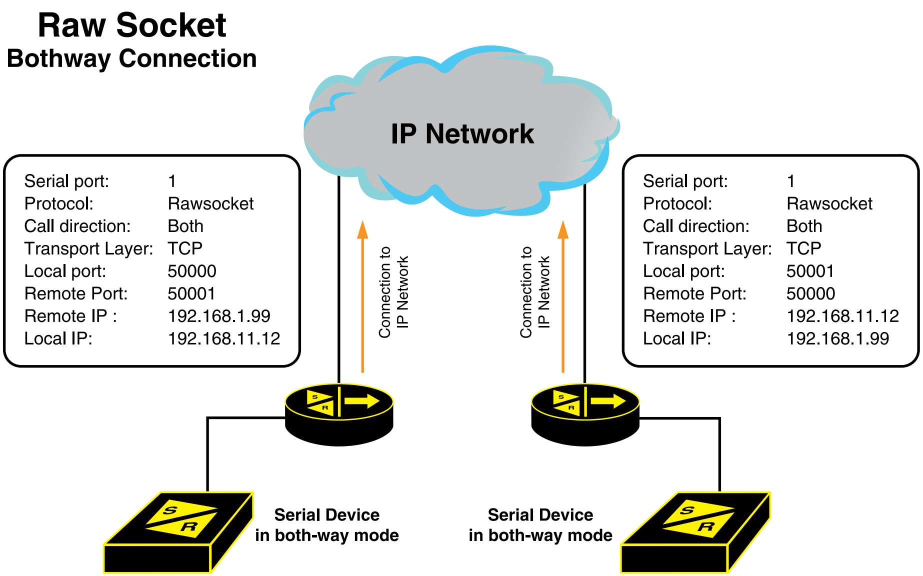

Figure 1 RaW Socket Operation

If the configuration is done as both-way as shown in Figure 1, any of the two sides can start the connection. The remote IP address and remote port are necessary to be configured for scheme to work.

Figure 2 shows the OSI Model applied to RaW Socket serial to Ethernet mode of operation.

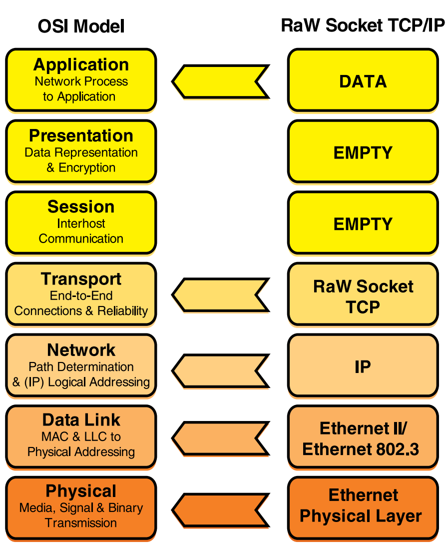

Figure 2 OSI Model of RaW Socket TCP/IP

RaW Socket encapsulation will permit encapsulating serial traffic into IP packets. During the encapsulation process a decision will need to be made about when to packetize serial information.

The following options are available on stay of the art serial server devices for Raw Socket encapsulation:

- **Packetize on receiving a specific character:** The server will examine each received character and will packetize and forward upon receiving the specific character. The character is usually a <CR> or an <LF> character but may be any 8 bits (0 to 255) character.
- **Packetize on timeout:** The server will wait for a configurable time after receiving a character before packetizing and forwarding. If another character arrives during the waiting interval, the timer is restated. This method allows characters transmitted as a part of an entire message to be forwarded to the network in a single packet, when the timer expires after receiving the very last character of the message.
- **Packetize on full packet:** The server will always packetize and forward on a full packet, i.e. when the number of characters fills its communications buffer (1K bytes).

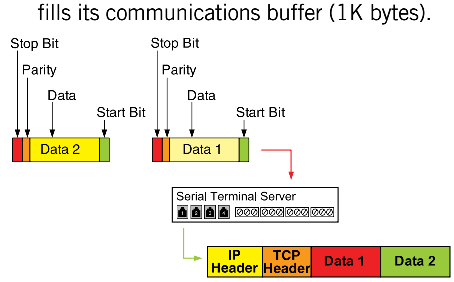

Figure 3 RaW Socket Packatization

Comparing Serial with Ethernet Communications

Comparing the characteristics of Serial vs. Ethernet communications, the following are the most important reasons when considering one versus the other:

1. **Reliability of Data Communication**
   The Ethernet is a secure and proven way of data communication with error connection handled by the hardware and the TCP world standard communication protocol.

   The primary limiting factor for shared-bus topologies like serial links is that of high I/O and limited distance.

2. **Speed of Data communication**
   Using Ethernet data is moving with a minimum speed of 1 Mbps with absolute error correction compared to RS232 where the speed is at best one tenth of the Ethernet's minimum, without or minimum error correction.

3. **Ethernet Better and Faster Recovery**
   Ethernet networks utilize redundant links and recovery protocols as protection techniques against link failures.

4. **Standardized Cable and Connection**
   For the Ethernet network the engineer is using world class unshielded twisted pair (UTP) cables and plugs however in the serial world there are no cable standards.

5. **Distance of Data Communication and Noise immunity**
   When using Ethernet technology the data can be error free at high speed of 1mbps minimum over distances up to 50m. When using the RS232 for speeds of 110kbps the theoretical distance for error free communication is relatively very short. This means that in the majority of cases the distance alone between the IED and the PC is a key factor to choose Ethernet over serial communications. Furthermore in noisy environments the Ethernet cable is proven to work while the RS232 or RS485 non standard cables offer no guarantee that may corrupt data.

Serial to Ethernet Migration Example

In the early 1970's, utilities began deploying communications to substations, in some cases having looped source feeds for the purpose of providing Distance Protection Pilot Schemes such as Permissive Overreach Transfer Trip (POTT) high-speed relaying between the substations.

Early communication circuits used dedicated copper leased circuits as the medium of transportation for the Frequency Shift Keying (FSK) relay equipment. In the late 1990's, they began installing fiber optic cables between the substations to enhance the relay protection system communications, in some cases utilizing Multiplexers on SONET using channel division at T1 speeds. Both of these methods are still in use today because a cost effective solution may not be available that could be used to retrofit existing configurations without the need to replace the relays to new, more advanced models that support Ethernet communications.

In early 2000's the need to consolidate substation communications to one common network platform was identified. The main reason for considering a change was simply to take advantage of additional benefits enabled by new technologies such as Ethernet. With time, Ethernet over fiber optics has been selected by many utilities as the medium to provide a communications highway; however, not all the Protection and Control devices currently in service have Ethernet connectivity. As previously stated, Serial Servers are probably the simplest and most economical method to bring serial devices to the local area network.

Once at the Local Area Network level, substation hardened Ethernet switches are also chosen due to their ability to provide a stable solution over fiber at link speeds of up to 1GB. SCADA RTUs, IP-based surveillance cameras, AMI meter collection nodes, protective relay engineering access and oscillography can be moved to the Ethernet network for integrated communications, allowing information to reach other stake holders within the Utility Enterprise.

In many situations, the move to Ethernet does not, however, provide an immediate solution to replace the legacy copper leased circuits for high-speed POTT relaying. Relay vendors choose to use proprietary rather then open protocols which, in most cases, are incompatible with standard serial communications parameters, preventing use of Ethernet for communications. Without an immediate solution to transport such protocols across Ethernet within the relay-required timing parameters, utilities must find methods to use existing relays over an Ethernet communications structure.

As described above, serial servers are used to create an IP tunnel between two serial servers across an Ethernet infrastructure. Once the data transfer is possible through the IP tunnel using the any standard or proprietary protocol over the network, users may find themselves facing timing and data integrity issues.

Since serial servers have proven their ability to transport data between relays, serial servers and relay vendors are working together to enhance their products to accurately transmit proprietary protocols over Ethernet. Bench tests have confirmed the solution to be effective. Initial tests proved that timing performance can be even better than expected, with confirmed data integrity for secure high-speed relay protection.

High Speed Relay Protection Layout

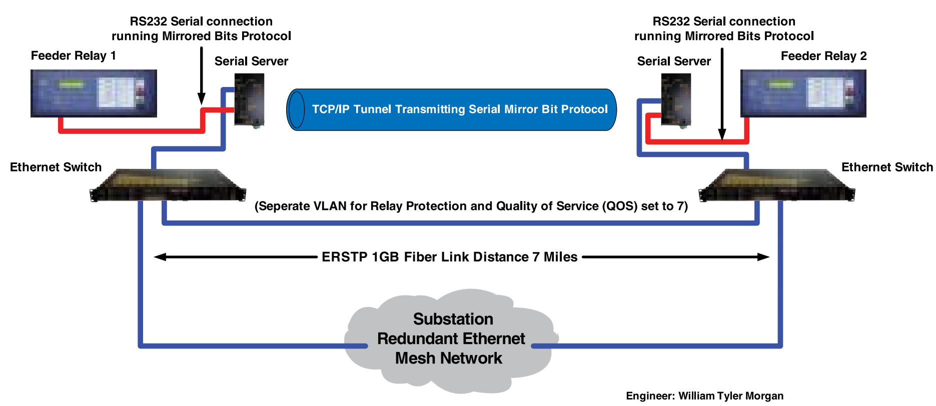

Figure 4 Network Topology

Installed Configuration

In the following example, two feeder relays are been connected back-to-back through a serial server which provides a TCP/IP tunnel or conversion and transport of serial peer-to-peer messages. While having a unique IP address, each serial server has also in records the destination IP address of the adjacent serial server to complete the TCP/IP tunnel.

It is important to note that TCP is recommended over UDP protocol because of the deterministic characteristics of TCP versus the broadcast approach of UDP and its ability to provide secure packet transfers.

The serial servers are connected to Ethernet switches used as the communications backbone between the substations, with 1GB fiber links in a mesh configuration to provide redundancy.

The use of Ethernet technology enables the following features:

- Enhanced Rapid Spanning Tree Protocol (eRSTP™) dynamically reroutes the network traffic in the event of a fiber break or equipment failure.
- Dedicated VLAN ensures interference-free performance of the high speed relay communications.
- Quality of Service (QoS) gives higher priority to packets containing peer-to-peer messages.

The communication circuit performance provided by the serial server has proven to be transparent to the operation of the relays, whether performing under fault conditions or simply monitoring the heartbeat of the companion relay.

Performance Measures

Before: Round trip time of peer-to-peer messages was 160ms (9-10 cycles) using legacy FSK equipment leased lines or the SONET-based Multiplexer.

Lab tests: Round trip time was measured at 40ms (2.5 cycles). The lab test consisted of 2 feeder relays connected back-to-back through 2 serial servers. The serial servers were connected to a standard Ethernet switch with no other network traffic present during the test.

Present: In live production using Ethernet switches between sites over Ethernet at 1GB speeds, the round trip time was less than 30ms (2 cycles) over an approximate ome-way circuit distance of seven miles. The total distance was 14 miles round trip in this installation.

Note: To provide accurate line fault protection, one substation relay must send a request to trip to the other substation relay and receive permission to trip within 9 or 10 cycles.

Conclusion

Based upon performance test results, serial servers have proven to be an effective alternative to transport peer-to-peer messages using proprietary protocols between relays over an Ethernet Network. This will replace existing frequency shift keying (FSK) systems over leased lines that provide this service hence reducing the overall operating cost. The main goal of moving substation communications to the fiber Ethernet network has now been achieved.

The Rapid Spanning Tree Protocol feature provided by Ethernet networks can now be used to increase the reliability and availability of data originated from serial devices. ■

About the Authors

***William Tyler Morgan** is a Network Engineer II at EPB of Chattanooga TN, which provides electric power to customers in a 600 sq mile+ coverage area along with providing High Speed Internet and Phone Services over fiber optics to businesses. For 20 years, Mr. Morgan has been involved in the design and installation of wired and wireless networks along with installing and supporting of Windows, Novell, UNIX, OS2 and Linux servers operating systems. Prior to joining EPB, Mr. Morgan worked for two network integrators that provided network engineering services. Mr. Morgan has been with EPB for 12 years designing and supporting internal and external networks, supporting multiple server operating systems along with converting all the substation systems to operate over one standardized network infra structure, including Protection and Control, Substation Automation, SCADA and mobilized wireless workforce installed in the EPB support vehicles with real time GPS tracking.*

***Jason Read** is a Senior Engineer at EPB of Chattanooga TN, which provides electric power to customers in a 600 sq mile+ coverage area along with providing High Speed Internet and Phone Services over fiber optics to businesses. For 15 years, Mr. Read has been involved in the design and commissioning of power substations. Prior to joining EPB, Mr. Read worked for 8 years at one of the premier nationwide turnkey solution providers for medium and high voltage electrical systems. Mr. Read has been with EPB for 7 years providing design and substation support for more than 125 substations that EPB operates.*

***René Midence** is the Utility Market Manager of RuggedCom Inc. a leading manufacturer of industrially hardened communications technology for mission-critical applications in harsh environments. For over 25 years, Mr. Midence has been involved in the design and commissioning of power substations and power plants, including Protection and Control, SCADA, Substation Automation and Substation LAN systems. Prior to joining RuggedCom Inc. Mr. Midence worked for GE Multilin over 8 years as Senior Technical Support and Applications Engineer and 2 years as Product Manager responsible for Industrial products. Mr. Midence graduated from the University of Honduras in 1983 with a Bachelor of Applied Science degree in Electrical and Industrial Engineering. Mr. Midence is a member of Institute of Electrical and Electronic Engineers (IEEE) and International Electrotechnical Commission (IEC) TC57 WG10.*

EPB is an electric distribution system that purchases 100% of its power from the TVA. EPB provides electric service to more than 168,340 customers in a 600-square-mile service territory encompassing the greater Chattanooga area.

An Integrated Utility Network

By Wang Chiu, IESO, Ontario and Michele Hudnall, Managed Objects

Courtesy of IESO, Ontario

Introduction

The business case for business service management (BSM) at Ontario's Independent Electricity System Operator, commonly referred to as IESO, started out as a proposal for solving a traditional IT management problem. Yet in the process of defining the problem and evaluating solutions, the IESO discovered a way to simultaneously enlist the endorsement of business users by incorporating the supervision, control and management of the power grid and its energy market systems into the IT project.

Efficient control is imperative when it comes to energy. Businesses and consumers in Ontario use more than 152,000,000 megawatt hours of electricity per year and the IESO is the not-for-profit corporate entity providing Reliability Coordinator and Balancing Authority services as system and market operator for the Province of Ontario. IESO dispatches generation in a competitive electricity market to balance the demand and generation. IESO deploys power systems elements to maintain a reliable power grid. IESO manages a competitive electricity market through demand forecasting and the operation of market systems for generators, traders, suppliers and consumers to buy and sell the energy required to meet that demand.

This orchestration of power trading and maintaining grid reliability is no small feat. The IESO's responsibility includes harmonizing supply and demand across more than 20 different power generation companies, five transmission companies and 91 utilities – in all, serving an estimated 13 million people in the Province. Ensuring that there is enough energy to meet that demand is an ongoing and highly-complex process, requiring the close coordination of people, process and technology.

To this end, the energy industry, including the IESO, has become increasingly reliant on technology, which has provided both benefits and drawbacks. Automation has delivered new efficiencies, but as energy and utility industry management platforms have evolved from proprietary host systems to complex distributed technologies, managing technology has also proven a greater challenge. All of this calls for an integrated technology network – one with a service-based approach.

Service-based Management

The specifics of the IESO's IT environment aside, considering the case from a purely IT operations perspective, the IESO's technology challenges are not unique to the energy industry. Across any vertical market, IT departments tend to struggle with aligning themselves with their businesses. Veterans on all sides will often observe that IT and the business rarely speak the same language – and more specifically, neither group truly understands the impact of IT in the context of business.

The symptom can be traced to the way IT operations has traditionally managed the IT infrastructure. For the last twenty years, IT has managed the infrastructure in the same manner in which it was originally defined – in silos. That is to say, IT has been managed as individual elements, for example, as servers and network components. In addition, IT-centric metrics have often been applied to measure success or failure – a typical benchmark is availability – whether a server is "up" or operational 99.999 percent of the time. Yet such metrics leave a central question unanswered – what is the business impact of that server's availability?

Few end-users care whether or not a server, a switch or a router is up or down; rather users care whether the business service is working – services that incorporate IT and business processes, such as e-mail, the ERP system or financial management applications. In the IESO's case, business users were most concerned with the availability of systems deploying a reliable power system or facilitating energy trading – not with underlying components that make up these systems. End users at the IESO desired an improved method of IT management – service management, or more specifically, business service management.

Sea of Red

For many in IT operations, Business Service Management is the holy grail of IT management. It may also seem a vague or idealist goal. This may be because IT operations are drowning in a sea of red – a direct result of component-based IT management – and a reference to the red, yellow or green color code of traditional IT management tools. Generally, when alerts and events stemming from management systems are initiated – be that network, systems or application performance tools – the alerts are presented on a component basis as opposed to in the context of business impact. [Figure 1]

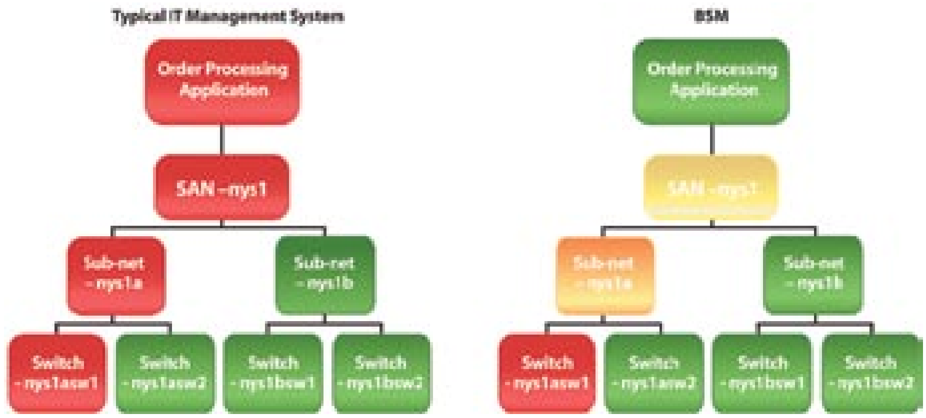

Figure 1: Courtesy of Managed Objects

An example of a common component-based management shortcoming is when an alert refers to a server or network router outage, but without information regarding how this impacts the application or services. If there is redundancy in the network, as there often is, a single router may not in fact be severely disruptive to the service. By contrast, if it's a server on which multiple critical applications are dependent, the outage would be very serious. Yet, commonly both alerts are issued at approximately the same time. Traditional IT management tools give operations no way to distinguish between two or to prioritize based on impact. More than likely, alerts are addressed in the order in which they are received.

Compounding this problem is the growth of technology. As technology has evolved and matured, so have the number of components, systems, and infrastructure devices that comprise any given business or business system. The increasing complexity of these underlying components that comprise these systems, while providing the end-user with more value and capabilities, have created an even more challenging environment. The volume of alerts has simply grown beyond the human ability to manage. As such, unless the IT operations can understand the impact of an outage on the service involved, the frequency, duration and adverse business effects are likely to be increased and prolonged.

Silos of Data

If priority and impact alone weren't complicated enough, the mix of heterogeneous technology components, from various vendors within their infrastructures, has trapped IT organizations into using a number of existing IT network, systems, and applications management tools to monitor the health of their IT environment. Because roles and responsibilities are commonly segmented by functional discipline – that is network experts, application specialists, database champions and so on

– each specialist is focused on managing their part of the IT infrastructure. These operational silos in combination with their distinctive IT management tools create silos of data. [Figure 2]

Figure 2: Courtesy of Managed Objects

To be valuable, this information must be manually consolidated and correlated in order to achieve end-to-end management and understand the impact on performance. It's a labor-intensive process consumes countless hours of precious IT resources and slows IT problem resolution.

Translation to Impact

Business Service Management is a fundamental shift in the way technology is managed. Instead of managing technology as individual components BSM dynamically links these components to the services delivered to the business. With strong integration capabilities, BSM translates event data – that is data about the status of an individual component – into impact. In other words, BSM is a platform of information that illustrates the impact of IT with respect to the business.

In complex environments it's not uncommon for enterprises to have thousands, even hundreds of thousands of components in their infrastructure – each of which is capable of incurring downtime and generating an event alert. The ability to translate event data into impact is inherently valuable and requires the integration of data from existing IT management tools onto a single pane of glass. In other words, vendor agnostic BSM solutions enable users to leverage their existing investment in application, network and system management tools – extending their value – and simultaneously understand the impact to business.

As with many large organizations, the IESO's IT environment was as complex as it was critical. The IESO has a heterogeneous IT shop that counts a combination of Compaq and Sun machines and also three different monitoring tools including HP OpenView, IBM Tivoli and Microsoft MOM. As such, it wasn't unusual for IT operations to have four or five different screens in front of them, all showing slightly different views of the enterprise. n this way, the IESO's IT operators often found themselves inundated with alarms, that were void of context and with no business driven way to prioritize them. I Therefore the justification for a BSM initiative seemed simple and straight forward and the IESO's IT department began to research and develop a BSM project it called CAMS (Central Alarm Management System).

IT Finds a Conductive Partner

IT can be a lonely department when lobbying for technology spending. By some market-watcher estimates, up to 60 percent of the large enterprise's IT budget goes towards IT operations. In other words, more than half of a typical IT budget goes towards keeping things running. The other 40 percent is spent on human resources and this often leaves little in the way for strategic IT investments. However, in formulating a business case to justify the implementation of a BSM project, the IESO's IT operations knew their business users were facing similar challenges. Business users – that is staff monitoring the flow and the buying and selling of electricity – were also reliant on technology management tools of a different sort. In addition to multiple market systems that facilitate Ontario's electricity marketplace, much in the way a financial service firm might support online trading, the IESO's system operator uses a SCADA/EMS (Supervisory Control and Data Acquisition/Energy Management System) to manage the electricity transmission grid.

In principle, SCADA/EMS works in a similar fashion as IT management systems. For example, a sharp rise or drop in voltage on a transmission grid can easily damage electrical equipment and appliances. Much in the way an IT management system trips an alarm if a server goes down, voltage, current or other operational fluctuations can cause SCADA/EMS alarms. The IT operations knew that the control room operators were also considering ways to enhance their existing alarm functions through the consolidation of the various systems. The IESO's IT department and the control room operators had been looking for an opportunity to consolidate both electricity and IT management systems into a single operations management system project.

Preventing cascading events

The IESO had another vested interest in integrating electricity grid and market systems management into the CAMS project by: providing even more information than they already had to assist them in the prevention of cascading events. As part of the North American Electric Reliability Corporation's (NERC) investigation of the blackout of August 2003, which was initiated in Ohio, regulators found that failure of the system monitoring and control functions over the electricity grid were contributing factors to the blackout. Such failures caused operators to either delay or altogether miss corrective measures for which the company managing that portion of the grid was responsible. Consequently, the events cascaded and rapidly spread across the region. NERC later assessed that the operator's monitoring system did not meet NERC requirements.

Although benefits are difficult to precisely quantify, there is little doubt that a power grid failure – especially a preventable failure – has large and perhaps unnecessary financial effect. The Anderson Economic Group estimated the economic impact of the August 14, 2003 blackout was US$5,000,000,000. The Toronto Dominion Bank estimated the cost to the Ontario economy to be CAN$550,000,000.

Even momentary interruptions to the power supply could prove costly. A brief power interruption on April 16, 2005 in Pittsburgh, Pa. that forced a plant shutdown had an impact on the plant owner's earnings in the range of $20 million to $25 million after tax.

Even though IESO monitoring tools had always met NERC requirements, the IESO wanted to enhance its existing grid and market monitoring tools. Likewise, users were looking to prioritize and manage alarms with role-based alarm views.

CAMS, along with the proper business logic, would augment the IESO's system operators' ability to operate a reliable and competitive electricity market. IT now had a business partner and a good case for BSM: creating a system that was to also be used by business users meant the IESO had a project supported by more than just IT.

The Business Case

The business case for the IESO's CAMS centered on providing a flexible central alarm system with the capability to consolidate, correlate and provide service-based management of alarms across a range technological components on a single pane of glass. This included applications and components from traditional IT infrastructure, and also control room alarms from the SCADA/EMS in addition to the sensitive, customer facing market systems that facilitate the energy trading environment.

The IESO considered alternative courses of action for solving this challenge: a) upgrade existing management systems, b) build a custom system from scratch, or c) select a BSM software vendor with ability to integrate all the disparate systems onto a single console.

Upgrading the existing management systems to include the three different monitoring systems in HP OpenView, IBM Tivoli and Microsoft MOM would not provide IESO a centralized, consolidated view of the system. By the same token, building a custom system from scratch would not only be expensive to build and maintain, but it would also include inherent project risk and take a great deal of time to complete.

In a research study by Fujitsu Consulting, Managed Objects had been determined to be one of the industry leaders. Further, the company has demonstrated it had successfully implemented its product in several industries including energy, financial services, government and telecommunications. As a final test to ensure capability, the IESO instituted a three-month proof-of-concept before finally selecting Managed Objects as the vendor.

Reaping the Benefits

Today, the IESO has successfully tapped BSM to develop an integrated utility network. IT operations aside, it has modeled five services that are critical to the business, including IT operations, SCADA/EMS and several market systems. This, in turn, has led to more efficient and effective management of technology and has better aligned the IESO's IT operations with the business operations. In the end, this has greatly simplified the management of technology governing energy transmission and market trading systems.

Specifically, the IESO identified wholly positive results along four critical dimensions:

- Seamless integration was a pivotal achievement since the IESO already had substantial investments in existing and federated IT management tools. In addition, the integration of non-traditional IT management systems such as the SCADA/EMS required the use of special communication standards to enable these separate systems to interoperate. The neutral approach to integration enabled the IESO to meet these requirements and to avoid additional investments in additional tools that can often trap enterprises in being dependent on a single vendor.
- Protected investments meant that the IESO was able to continue to leverage data arising from it existing investment in IT management tools including HP OpenView, IBM Tivoli and Microsoft MOM.
- Service modeling was an important accomplishment and the basis for prioritizing alarms. Mapping thousands of underlying infrastructure components to services or applications, could prove an onerous task. Managed Objects BSM provided automated modeling capabilities to facilitate this process.
- Role-based analytical views were also a key result since user communities can now have visualization requirements tailored to their specific roles at the IESO. For example, the control room operator does not need to see event alarms stemming from HP OpenView but would want to be aware of information arising from its SCADA/EMS systems. Other role-focused views include single-sign-on views tailored specifically for those monitoring one of the five critical services such as the market systems.

The energy industry is likely only to grow increasingly reliant on technology to manage its services and as such the line between IT and the business will only continue to blur. The ability to find and marry synergies between the business side of the IESO and IT operations has given way to an efficient new paradigm in the form of an integrated utility network. ■

About the Authors

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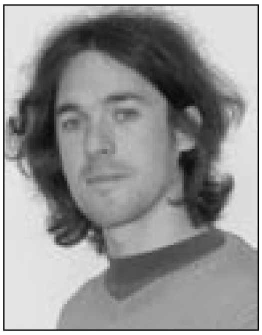
Prevention of Oil-Filled Transformer Explosions

By


Guillaume Perigaud Sébastien Muller Gaël de Bressy Ryan Brady Philippe Magnier

Transformer Protector Corporation

I. INTRODUCTION

Power transformers are one of the most dangerous electrical equipments because of the large quantity of oil they contain which is in direct contact with high voltage elements. Under such circumstances, low impedance faults that result in arcing can appear in transformer tanks once the oil loses its dielectric properties. Oil is then vaporized and the generated gas is pressurized because the liquid inertia prevents its expansion. The pressure difference between the gas bubbles and the surrounding liquid oil generates a dynamic pressure peak, which propagates and interacts with the tank. The dynamic pressure peak interactions with the tank structure generate reflections, which build up static pressure. Then, the static pressure rises leading to tank explosion and possible fire resulting in very expensive damages for electricity facilities, possible environmental pollution and human life risks.

To avoid such damages, the transformer explosion and fire prevention strategy presented in this paper, here called Transformer Protection (TP), is based on the direct mechanical response of a Depressurization Set (DS) to the tank inner dynamic pressure peak due to an electrical fault. Since transformers always rupture because of the static pressure at their weakest point, the DS is designed to be this weakest point in term of inertia to break with the dynamic pressure peak before the tank explodes. Thus during a transformer short circuit, the TP is activated within milliseconds by the first dynamic pressure peak of the shock wave generated by the electrical fault and before static pressure increases. It then depressurizes the tank by expelling the oil and gas mixture.

This fast direct tank depressurization method has been experimentally studied by arcing tests in industrial size oil-immersed transformers. Physical modeling and numerical tools, validated on collected experimental data, have been developed in order to test the TP reliability in various operation conditions. The following sections thus deal with:

- §2, brief description of the protection;
- §3, the experimental campaign carried out on arcing in large transformers;
- §4, the theoretical and numerical developments which results prove the reliability of the whole prevention strategy.

II. DEPRESSURIZATION STRATEGY DESCRIPTION

Mitigating the effects of a transformer explosion consists in either limiting the explosion consequences by extinguishing the subsequent fire (fire walls or sprinklers) or preventing tank explosion by using mechanical technologies that absorb the high overpressures generated by the electrical arc, thus preventing the tank rupture and the subsequent fire.

The explosion prevention technology presented in this paper is of the second sort. This fast-direct-tank-depressurization-based method activates as soon as the high pressure peak of the pressure wave reaches it.

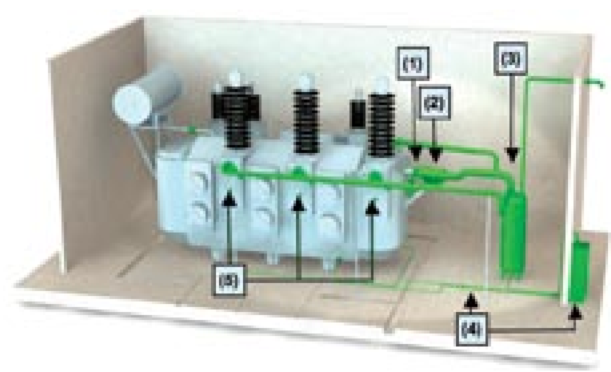


Figure 1: Transformer equipped with fast direct tank depressurization based method (TP)

Indeed, the electrical fault generates a dynamic pressure peak, which travels at the speed of the sound inside the transformer oil, 1,200 Meter per second (4,000 feet per second). This dynamic pressure peak bursts a rupture disc located in the DS (Item 1 in Figure 1). Oil and gas are then quickly expelled out of the transformer tank through the DS (located in 2) to an oil gas separation tank (item 3). The explosive gases are then channeled away to a remote and safe area.

Then, nitrogen is injected (item 4) to have the whole transformer safe, cool and ready for repairs. Note that additional DS can be placed in order to protect the OLTC or the OCB (item 5).

III. THE EXPERIMENTAL CAMPAIGNS

Up to now, two test campaigns have been performed, both under the worst conditions by creating low impedance faults leading to electrical arcs inside the transformer tank dielectric oil. In 2002, Electricité de France performed 28 tests. Then, in 2004, a second campaign of 34 tests was carried out by CEPEL, the Brazilian independent High Voltage Laboratory. This part presents the main conclusions of the last test campaign performed on large transformer tanks.

A. The CEPEL experimental campaign

The 34 tests carried out in transformer tank dielectric oil by CEPEL in 2004 were performed in order:

- to study the vaporization process induced by an electrical arc and the resulting pressure wave propagation,
- to evaluate a fast-direct-tank-depressurisation-based method to prevent transformer tank explosions.

Three standard transformers were used for these tests. The maximum distance between an electrical arc and the protection system ranged up to *8.5 meters (28 ft)*. Various physical parameters such as pressure, gas temperature, applied current, arc voltage and tank acceleration were studied in details.

1) Experimental settings

Each transformer was equipped with:

- arcing generation devices to master the arc location and make the tests repeatable,
- temperature probes,
- accelerometers, and
- pressure sensors at different locations in the transformer, in order to study the pressure wave propagation.

The transformer protection, the TP, was also installed on each transformer to study the ability to mitigate tank rupture by a tank depressurization method based on the fast and direct passive mechanical response of a depressurization set to the pressure wave.

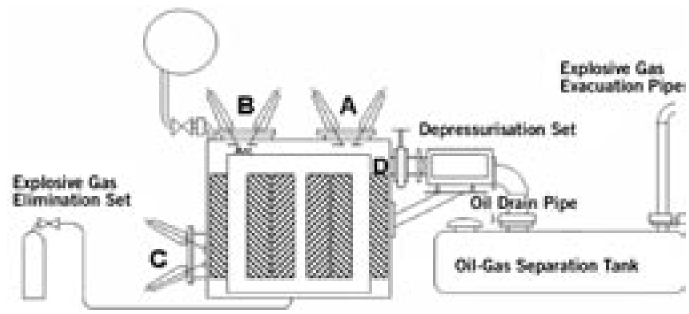


Figure 2 : Life Tests Transformer Principle Drawings

2) Experiments

To study in detail the pressure wave propagation influence, the electrical arcs were ignited at three different locations, as shown in Figure 2: on the top cover close to the Decompression Set location (position A), on the top cover opposite the Depressurization Set location (position B), and in the lower part of the tank opposite the Depressurization Set location (position C). The position D shown in Figure 2 is the location where the depressurization set was installed.

Most of the tests were carried out with electrical arcs with currents ranging from *5* to *15 kA*, and fed during *83 milliseconds*. This duration corresponds to the average response time of an old circuit breaker and was chosen to maximize the generated gas volume.

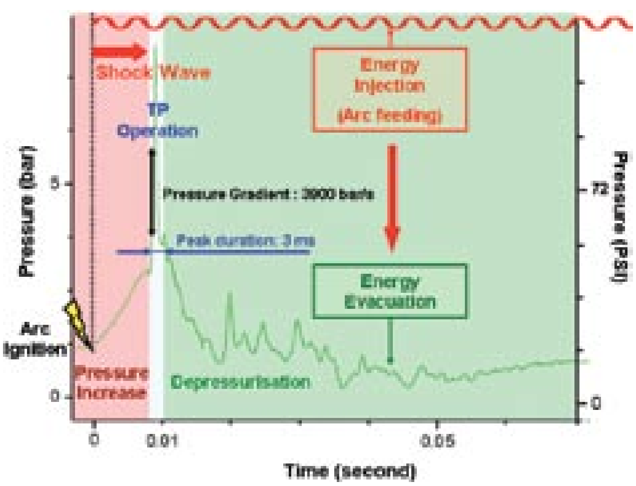
B. Transformer Explosion Prevention: Test Results Analysis

1) Generated gas

During the CEPEL test campaign, the electrical arc produced from *1* to *2.3* m^3 *(35* to *88* ft^3*)* of gas. For the tested energy range, the gas volume generated during an electrical arc is a logarithmic type function of the arc energy, which seems in accordance with the vaporization process and especially with the saturation of the vaporization for high energy arcs: the arc remains in the generated gas volume using its energy to crack the oil vapour rather than continuing directly vaporizing the oil, which results in a smoother vaporization process.

2) Pressure Profile Evolution at a Single Location

The pressure at a specific location in the transformer after an electrical arc has occurred is transient as shown in 3, where an experimental curve of the pressure evolution close to the arc location after the arc ignition is displayed.



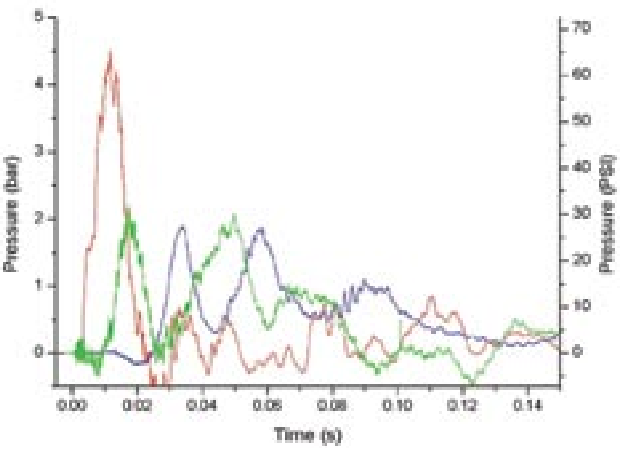


Figure 3: Experimental Pressure Measurements

After the arc ignition the pressure locally rises and reaches a maximum level; the waves, generated by the arc, propagate at a finite speed through the transformer and burst the rupture disc with a pressure gradient of 3900 bar/s (56000 psi/s). Three milliseconds after the rupture disk burst, the pressure is back to the activation level. Some secondary peaks, much lower than the first pressure maximum, can be observed; they are due to wave reflections off the tank walls and reflected waves interactions.

As soon as the TP has activated, it can be noted that the arc can be fed for a period much longer than the standard opening time of a circuit breaker. Even in this severe condition, the pressure would remain at harmless levels for the transformer tanks.

3) Pressure Wave Propagation

In Figure 3, three experimental pressure profiles are displayed. Each curve shows what happens near each sensor located in positions A, B and C (see Figure 2).

The arc is generated in C and the shock wave propagation can be followed step by step because of the pressure peak's displacement from C to A. The other pressure peaks (smaller than the main peak) are due to wave reflections off the walls.

The pressure does not rise spatially uniformly in the tank. The experiments show the pressure waves propagate in the oil at a finite speed.

4) Pressure Peaks

- Only one main pressure peak has been noticed for each test. The pressure profiles show variations after that main peak but their magnitude remains low compared to the first pressure peak level. They are due to waves reflections.

- The pressure peaks' amplitude is determined by the created arc. This peak ranges from *+1.5* to *+13* bar (*+21.75* to *+188.55 psi*) for arc energies from *0.01 MJ* to more than *2.4 MJ*.
- The pressure peak's values do not strongly depend on the arc energy since when comparing tests for which pressure peaks respectively equal *+8 bar* (*+116 psi*) and *+8.8 bar* (*127 psi*), the maximum pressure only varies in *0.8* bar (*11.6 psi*) while the corresponding arc energies vary within on order 10 of magnitude (*0.1 MJ* and *1 MJ* respectively).

5) Tank Withstand

To static pressure: To check the mechanical properties of the transformers, static tests were performed before applying any low impedance fault. The withstand limit was found to be *+0.7 bar* (*+10.15 psi*) for the biggest transformer, T3. This limit (*+0.7bar*, *+10.15 psi*) was used in the analysis as a threshold for tank depressurization during the dynamic tests.

To dynamic pressure: Even if the local pressure measured during the dynamic tests is on average 6 or 10 times higher than the static withstand limit, no tank damage and no tank permanent deformation occurs because the pressure peaks are very short. In fact, the structure can locally withstand high dynamic pressure increases because of the walls' elasticity and the prevention method small inertia to operate.

6) Operation of the Transformer Protection

On average, the TP has activated after about 20 milliseconds (minimum: *4.64ms*, maximum: *45.7 ms*) after the arc was ignited. Because the pressure wave propagation speed is finite, the maximum distance between the arc location and the TP is the parameter that matters the most for the activation. In the worst situation, the arc occurs in the transformer lower part opposite the Depressurization Set (location C).

The depressurization time is the time between the TP opening and when the pressure is definitely under the level of *+0.7 bar* (*+10.15 psi*). On average, the TP depressurizes the tank in *116ms*, with a minimum value of *19.7ms*, and a maximum of *347ms*. This experimentally proves the TP ability to depressurize the transformer tanks within milliseconds and prevent the explosion. The previous experimental data are also used in the numerical tool validation, which is the subject of the next sections.

IV. NUMERICAL SIMULATIONS

A. Mathematical, Physical, and numerical Modeling

The set of equations used to theoretically and numerically describe the phenomena is a model for 3D compressible two-phase flows that is based on a set of Partial Differential Equations (PDE), which governs the hydrodynamic behavior of mixtures. It is described in reference [1].

One of the major and most interesting model's characteristics is its ability to accurately depict the pressure wave propagation inside liquids and gases. Physical effects such as gravity, viscosity, and heat transfers are added in the modeling in order to be as close as possible to reality. It is detailed in reference [2].

A Finite Volume Method is thus adopted to numerically solve the PDE's system (see [1]). It allows describing precisely complex geometries such as transformer tanks.

B. Numerical simulation results

As showed in [2], simulations manage to give results in accordance with the experimental results, for a relatively low cost and without any danger. They were thus used here to compute the consequences of an electrical arc appearing in a tank not equipped with a TP and also to compute the protection operation on a very large transformer.

1) **What would happen without protection during the CEPEL tests?**
Experimental testing would be dangerous if the transformer is not protected against explosion so numerical simulations were performed instead. Performing computations for a geometry and for arcing conditions similar to those of a CEPEL test shows that, after the arc feeding, the average pressure remains close to an equilibrium state equal to *7 bar (100 psi)*, much higher than the static withstand limit pressure.

Thus, during this test, if the transformer had not been equipped with the TP, the inner average pressure would have risen up to the static overpressure withstand limit. The transformer would have exploded as soon as the tank wall elasticity limits were over, i.e. as soon as the tank walls could not store any more mechanical energy due to the pressure increase.

2) **Numerical simulation results: Explosion Prevention on a Large Transformer (400MVA)**
A *400 MVA* transformer *(7.8 m (25.6 ft)* long and *4 m (13 ft)* high) is considered in that section. An electrical arc (*11 MJ-arc* generating about *3.3m*^{3} of gas) ignites near a bushing, generating a *11 bar (160 psi)* gas bubble.

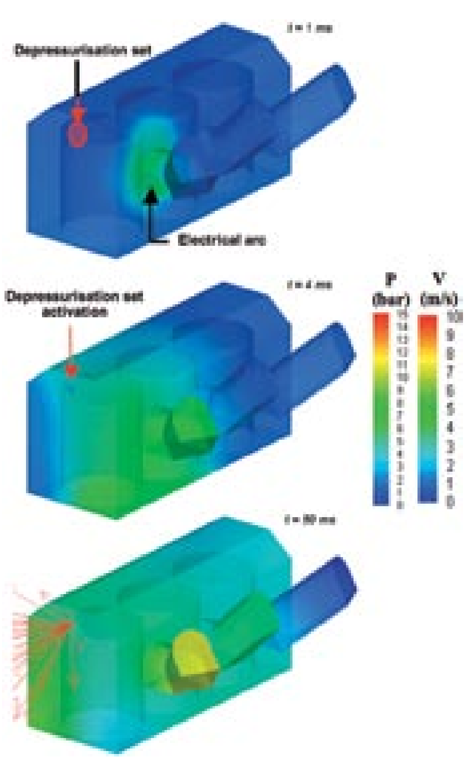


Figure 4: Chronology of the Prevention Technology Operation up to *50 ms*

When the transformer is equipped with a TP, Figure 4 and Figure 5.a clearly show the pressure propagation inside the tank and the drain operation as soon as the first pressure peak has activated the depressurization set (*4 ms* after the arc occurrence, Figure 4).

The drained oil velocity is represented by vectors which color accounts for the velocity magnitude, V, ranging from *0* to *10 m/s* (*0* to *33 ft/s*).

The drain gives place to the pressurized fluids so that after *120 ms*, the pressure is back to safe levels (see Figure 5.a).

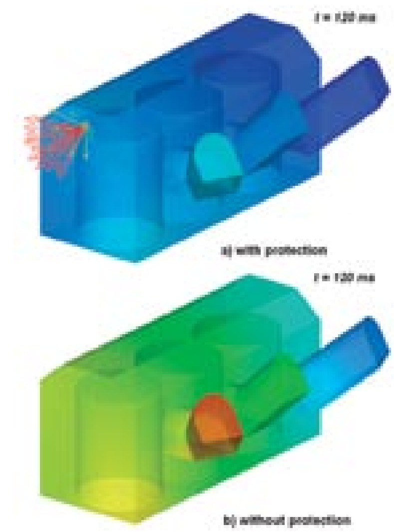


Figure 5: Inner Tank Pressure Evolutions a) with and b) without protection – Protection Efficiency Illustration

Otherwise, when the tank is not equipped with any protection system, and if it is subjected to a similar low impedance fault, the tank is still exposed to very dangerous pressure levels (up to 15 bars, 217 psi) after 120 ms (Figure 5.b): without the tank protection, the static pressure stabilizes around 7.5 bars (109 psi) and the transformer explodes. A technology based on a fast tank drain has thus a very positive effect on the tank protection.

V. CONCLUSION

TPC's vocation is to study the prevention of explosion for all transformers and all types of rupture of insulation and its research program philosophy is to maintain a strong connection between experiments and the theoretical developments.

The experiments made by EDF as well as CEPEL showed the efficiency of the explosion prevention method. This one is based on the fast tank depressurization induced by the quick oil drainage out of the transformer. The oil drainage is triggered by the direct and passive mechanical response of a depressurization set to the pressure wave. Thus during a transformer short circuit, the TP is activated within milliseconds by the first dynamic pressure peak of the shock wave, avoiding transformer explosions before static pressure increases.

The tests' results were also used to validate the computer simulation tool by comparison with experiments. Computer simulations were performed and highlighted the prevention technology's ability to efficiently depressurize larger transformer tanks when subjected to internal arcing of high energy level. ■

VI. REFERENCES

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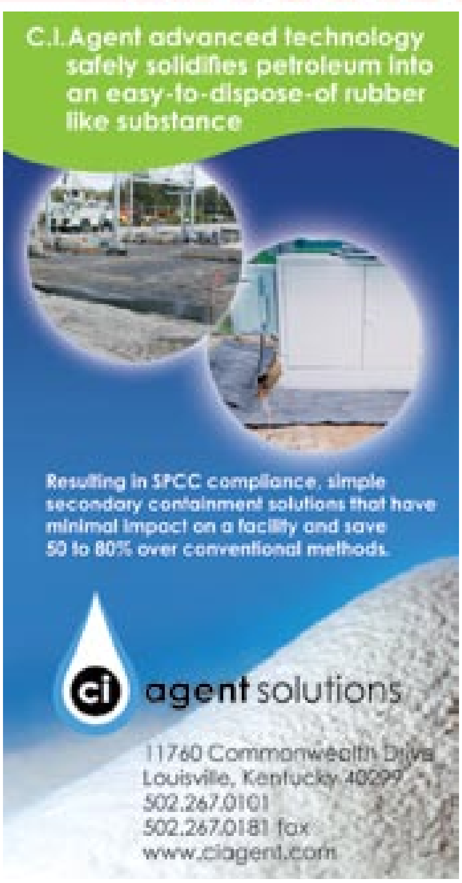

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