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North American Policies and Technologies

Electricity Transmission & Distribution Today

The Electricity Forum

Areva T&D explores new territory

Selecting, Upgrading, and Retrofitting Switching Systems for Substations in the 12st Century

Frequency Response Analysis of Power Transformers

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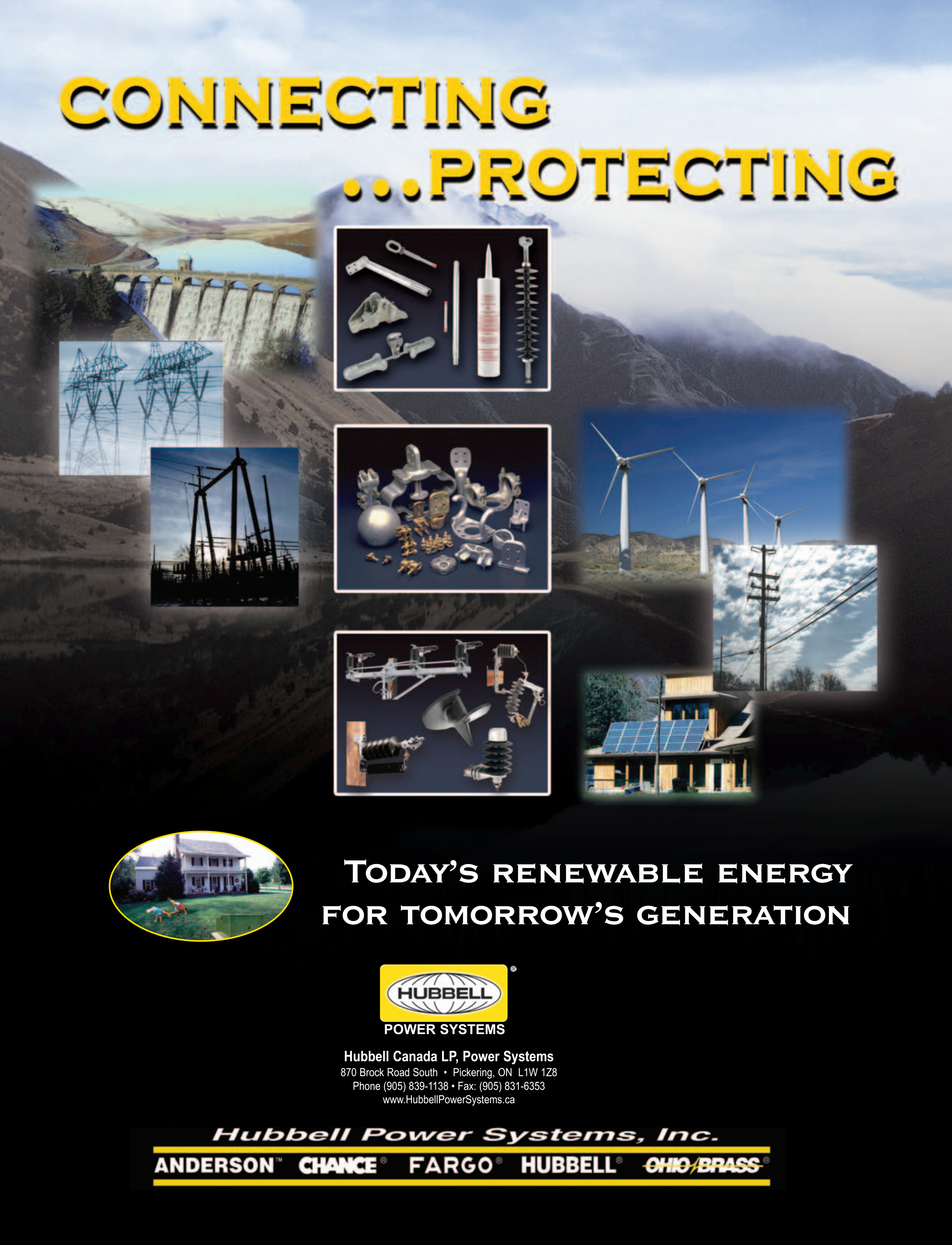

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ELECTRICITY TODAY

Volume 17, Issue 6, 2005

in this issue

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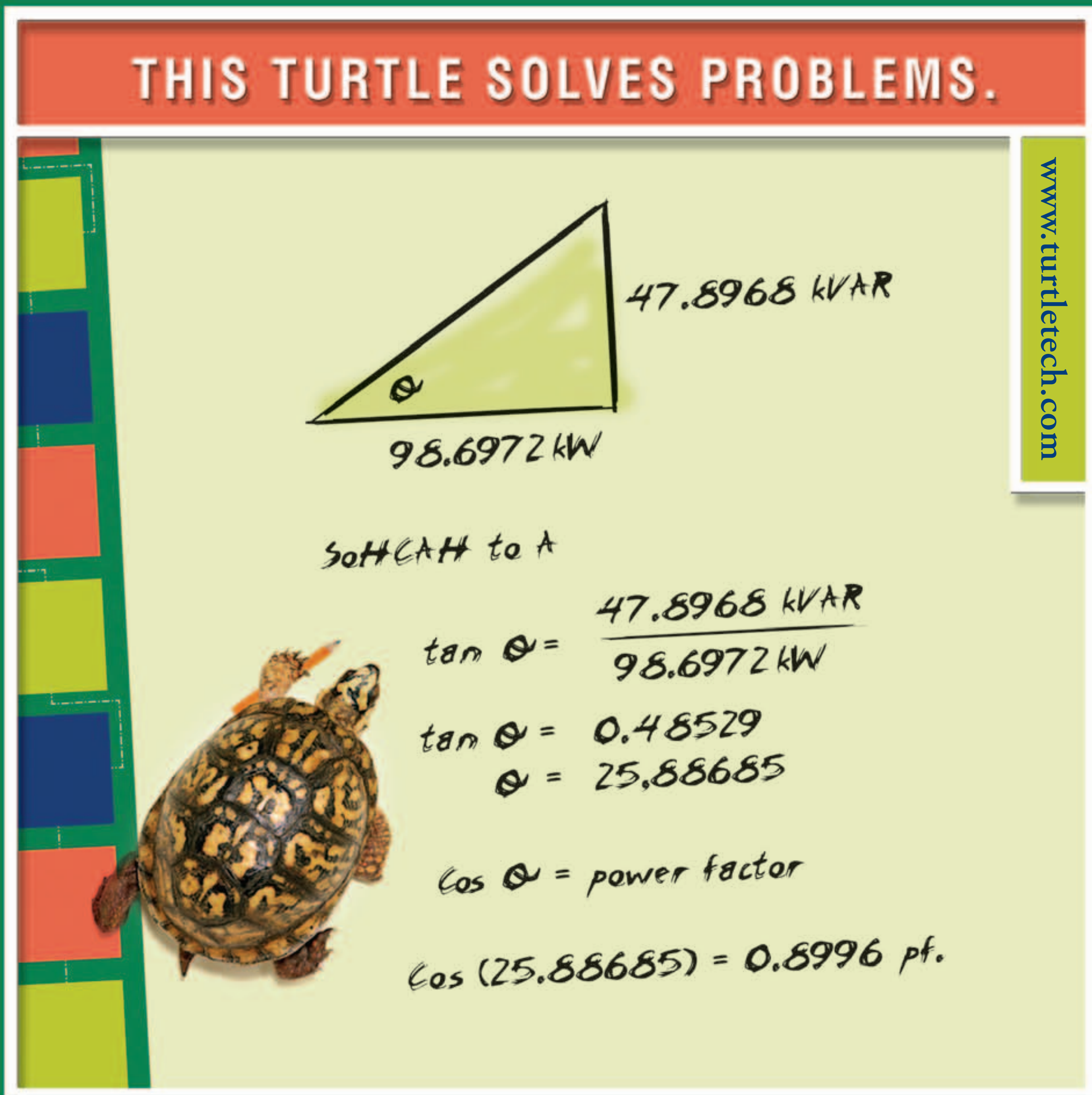
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HEAT WAVE GENERATES QUESTIONS ABOUT ONTARIO'S GENERATION CAPACITY

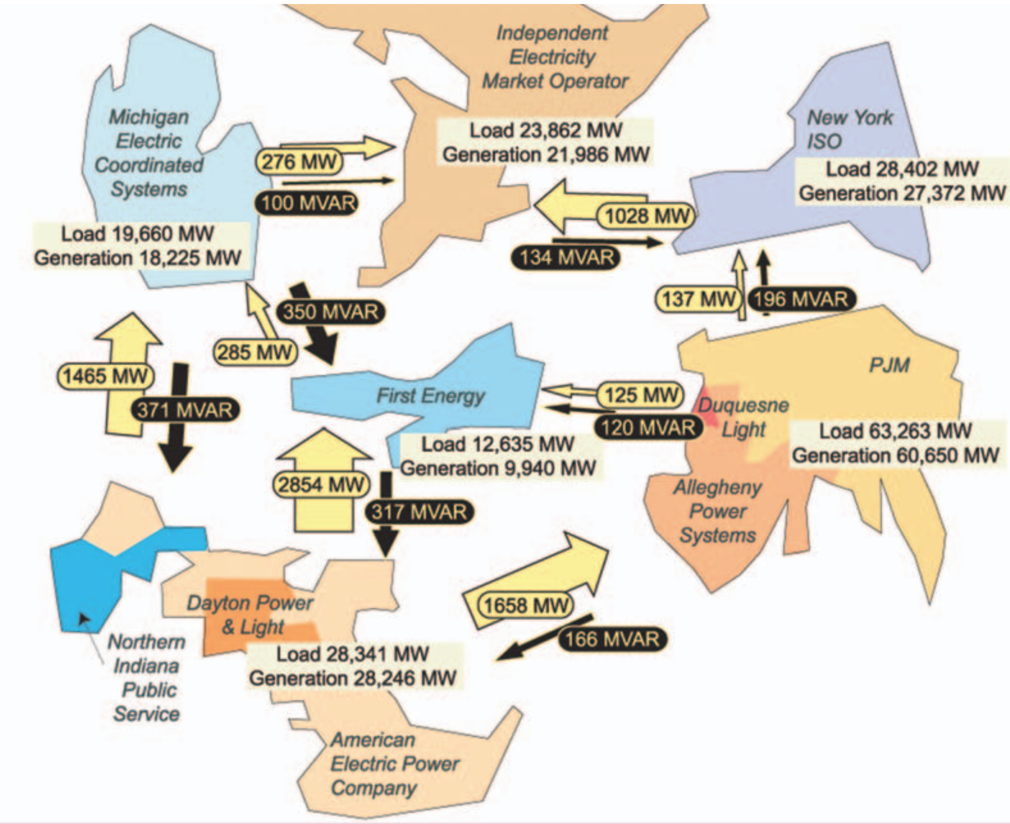
By Don Horne

After the August blackout of 2003, it finally hit home that Ontario's generating capacity had fallen dangerously close to not meeting peak demand.

During the week of July 11-15, demand reached 26,170 megawatts, forcing the Independent Electricity System Operator (IESO) to ask residents to scale back power use between 8 a.m. and 10 p.m. The week previous, the grid operator issued a 10-year forecast that Toronto could face rolling blackouts during heavy demand times to stop transmission facilities from overloading.

Again during the week of August 8-12, the IESO asked consumers to reduce their power usage.

Ontarians used more electricity on July 13 than ever before with the 24-hour demand totalling 532,500 megawatt hours (MWh). Consumption records for both June and July were also set this summer. Hourly demand has already exceeded 25,000 MW on 53 occasions, as compared to 19 occasions in the summer of 2002.



Generation, Demand, and Interregional Power Flows on August 14, 2003, at 15:05 EDT.

As the heat waved continued, Ontario was forced to import up to 3,400 megawatts, or 13 per cent of its power needs, from neighbouring U.S. states and provinces.

At one point, the price of power had risen to nearly 39 cents a kilowatt hour (normally it is in the 5-cent to 10-cent range).

Although household consumers will only be charged 5 cents a kilowatt hour for the first 750 kilowatt hours of power they use each month (5.8 cents for the remainder), the cost of importing all this power will ultimately fall on the shoulders of Ontario taxpayers (not to mention the debut incurred by the old Ontario Hydro, which currently stands at $20.6 billion).

Alexandra Campbell, spokesperson for the IESO, says that purchasing power outside of Ontario is predominantly a matter of economics.

"We've had to rely on imports because it is cheaper than the generation available in Ontario," says Campbell. "In general, it is more economically feasible to import, based on the market clearing price of all generators."

For 2004, the IESO purchased 6 percent of their electricity from the United States. That figure is expected to rise for this year.

To meet this summer's demand levels in June and July, Ontario generators produced 26.9 million MWh of electricity, 1.2 million MWh more than during the same period in 2004.

Although the cost escalates considerably during high demand periods (like the current heat wave that has amassed more than 30 days of plus 30 Celsius weather), Campbell says that the price overall is still reasonable.

"It is only a few days over the year (when prices are over 30 cents a kilowatt hour)," she points out. "When taken in perspective, that's 8.2 cents for the month of July on average."

Although purchasing power from outside the province is meeting peak demand at the moment, the IESO does see a need for new generation within Ontario as paramount to meeting future demand.

"We need to see timely progress, like the more than 3,300 megawatts of

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COGENERATION PROJECTS WILL SAVE MORE THAN $800,000 ANNUALLY

The Foothill-De Anza Community College District in Los Altos Hills, California announced it has completed the installation of more than 780 kilowatts of solar electric and energy-efficient cogeneration projects at both Foothill and De Anza colleges, including a moving solar-paneled parking structure that tracks the sun as it generates power.

Along with prior improvements to lighting, air conditioning and energy management systems, the installations will reduce the district's electricity purchases by 46 percent -more than 11 million kilowatt-hours annually - and save the district about $800,000 a year.

The projects, which are funded in part from the energy savings they create, reduce the district's operating costs while lowering demand for power from the local utility, which in turn benefits the environment by reducing greenhouse gas emissions. The district's reduction in purchased power from the local utility translates to avoided local carbon dioxide emissions of more than 14 million pounds per year, equivalent to planting more than 2,000 acres of trees.

The Foothill-De Anza Community College District enrolls more than 40,000 students each quarter and serves the communities of Cupertino, Los Altos, Los Altos Hills, Mountain View, Palo Alto, Sunnyvale and portions of San Jose.

"We're proud to serve as a model for educational institutions statewide and across the nation in achieving energy sustainability, preserving the environment while reducing energy costs and thereby maximizing resources for students," says Foothill-De Anza Board of Trustees Chancellor Martha J. Kanter. "We're pleased that through these energy efficiency methods as well as other means - such as through the Kirsch Center for Environmental Studies - we can educate students and the community about sustainability and the environment."

The Kirsch Center, the Science Center and the Student and Community Services Center at De Anza College are constructed to LEED (Leadership in Energy and Environmental Design) Green Building Rating System(TM) standards for high-performance, sustainable buildings. The Science Center opened in fall 2004, and the Kirsch Center and Student and Community Services Center will open for the upcoming fall quarter.

The projects were designed, engineered and constructed by Chevron Energy Solutions, a wholly-owned sub-

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METERING DATA AIDS ASSET OPTIMIZATION

By Betsy Loeff, AMRA News Writer

"Monthly usage data is almost irrelevant for designing a distribution system," says Kevin Cornish, director of utility solutions for Distribution Control Systems Inc. "The monthly consumption figure a utility sees may have climbed steadily, or the usage might have occurred between 4 p.m. and 8 p.m. each day. With monthly data, you just don't know." Cornish also notes that the historical practice of using monthly consumption data and demand profiles based on customer classes lacks the accuracy and flexibility desired in today's climate of reduced capital expenditures.

Using monthly consumption data, the process of sizing transformers or placing capacitors—in fact any distribution system planning task—has an element of guesswork included with the analytic tools and engineering. But it doesn't have to. Electric utilities with fixed network AMR systems can use frequent interval data to monitor distribution system assets, plan investments and more. Read on to see how some utilities gain by using detailed metering data—not assumptions—for engineering analysis.

BEYOND ASSUMPTIONS

Although load studies enable engineers to make assumptions about usage patterns, Cornish points out that many utilities are using studies age 20 years or older. Have consumption patterns remained constant over the past 20 years? Probably not.

For instance, most areas across the United States have seen a dramatic increase in the usage of residential air conditioners during the past 30 years. According to the Department of Energy, the percentage of U.S. housing with central air conditioning jumped from 23 percent in 1978 to 47 percent in 1997. In the

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sidiary of Chevron Corporation that provides energy efficiency, conservation and renewable power projects for public institutions throughout the United States.

"As a result of these improvements, the district is able to significantly reduce its electricity purchases while helping the environment," says Jim Davis, president of Chevron Energy Solutions. "We're delighted to have partnered with the district in projects that promote sustainable development."

The latest improvements at the colleges included eight 60-kilowatt Capstone micro turbines (four at each campus) that produce electricity plus heat recovery systems that heat each campus pool efficiently, and PowerLight solar photovoltaic-paneled parking structures that provide shade and together generate 301 kilowatts of electricity. In total, the cogeneration and solar systems can produce enough electricity to power more than 700 homes.

The $5.1 million total cost of the cogeneration and solar projects were offset by $2 million in rebates from the state of California. The remainder is being paid from the energy savings resulting from the new equipment and Measure E construction bond funds. ET

SELECTING, UPGRADING, AND RETROFITTING SWITCHING SYSTEMS FOR SUBSTATIONS IN THE 21ST CENTURY

By Jeff Rogers, Electroswitch

It's long been a given that automated, unmanned substations are the wave of the future. However, with all the convenience and cost-effectiveness they bring, there is still the need for manual backup controls, and for a very good reason: worker safety. For protection of on-site personnel there is nothing like the familiar trip handle of a Breaker Control switch for peace of mind during maintenance or repairs. And with the ever-present possibility of wide-scale system failures, or even terrorism, maintaining the capability for local manual control makes more sense than ever.

SUBSTATION UPGRADES SHOULDN'T SACRIFICE LOCAL CONTROL FOR REMOTE OPERATION

Even with the wide variety of sophisticated yet affordable relays and protective devices on the market today, the Power Industry continues to recognize the need for cost-effective, relatively fail-safe, manual controls.

For state-of-the-art new designs as well as piecemeal retrofits of existing systems, it remains imperative to allow local operators to safely and effectively override a SCADA or other supervisory control system.

There are many directions a utility can take to upgrade a substation, depending on needs and budget. Piecemeal "mix and match" improvements are common, partly because so many new switching devices are backward-compatible with older equipment. Some of the more versatile devices provide compatibility with modern supervisory control systems yet are engineered not to be software-dependent. Lock-Out Relays, Control Switch Relays, and Latching Switch Relays, for instance, provide the familiarity of a manual switch while allowing complete remote control capability. Versions of these rugged, reliable devices have long been available with a solenoid drive that can be hardwired to a pair of RTU control points. Newer models now coming to market acknowledge the industry's trend toward serial communications, in which each of several switching devices can be easily configured with a distinct address, allowing supervisory control through a local or wide-area network. These networked devices typically operate with either DNP3 or MODBUS® software protocols.

SWITCHING DEVICES THAT MAKE SENSE FOR THE FUTURE

Let's take a look at some of the proven switching devices that bridge the gap between manual operation and full software automation while preserving fail-safe operator intervention.

LOCK-OUT RELAYS (LORS)

Critical to almost every protection scheme, the Lock-Out Relay is usually slaved to an IED, protective relay, or other command device. When this device detects a fault parameter sufficient to warrant equipment shutdown, it sends a signal to the LOR, which immediately "trips," toggling its internal 30A contacts to open breakers, send alarms, and perform other necessary safety functions. LORs are available in a variety of configurations including manual-reset, self-reset, and electric-reset. Manual-reset models are reset by the operator turning the handle back to normal. The electric-reset LOR can be reset either manually or through command from supervisory control. Self-reset models modernize the electric LOR so it will reset automatically once the trip has been cleared (either instantly or according to a factory-set time delay). Standard trip speeds for electric- and self-reset models range from 12 to 15 milliseconds. However, these are also available in a high-speed (8 milliseconds or less) configuration.

CONTROL SWITCH RELAYS (CSRS)

Control Switch Relays, which combine the functions of a control switch and a SCADA-controlled interposing relay, are available with three basic control circuits, multiple-voltage capability, and a wide choice of contact configuration that allows the automation of virtually any breaker control switch function. When converting a manual substation to supervisory control, a CSR duplicating the existing manual control switch contacting replaces both the switch and the interposing relay without the need for special wiring or extra panel space. Blade-and-terminal construction and simple stacking procedures allow two independent low-resistance contacts per deck. Because the handle moves on SCADA operation, target flag agreement is always true regardless of manual or electric trip. The target always shows the last active position. CSRs are also protected to withstand control-bus transients up to 3.5KV.

On some CSRs, a push on the handle disables remote operation, allowing only local/manual control so that testing or service can be performed safely. In addition, these models provide push-activated N/O and N/C auxiliary contacts that can be used as SCADA feedback or local indication of status.

LATCHING SWITCH RELAYS (LSRS)

Versatile Latching Switch Relays can be slaved to IED relays as contact multipliers, configured to control local or remote latching or reclosing, or can serve as programming relays for local or SCADA-compatible switches. Because their low-resistance blade-and-terminal design allows for up to forty contacts, LSRs can be configured for manual and remote control of a wide variety of specific applications.

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Northeast, more than 41 percent of housing units had window air conditioners. That could certainly put a spike in a utility's load profile. Worse, air conditioner motors affect system power factors.

"Old assumptions and models are becoming a real issue in places like New York," says Chris King, chief strategy officer at eMeter, a company that creates meter data management software.

"Now that people can buy a window air conditioner for less than $100, more apartment dwellers are buying them," King says. "These air conditioners are very peaky. They only get used a few weeks a year and they're only used for a few hours, and of course, they're all used at the same time."

King adds that air conditioner motors create reactive power, which further increases the amount of power utilities must generate.

"Substations, transformers, taps, fuses — for most utilities today, all the aspects of the electric system are sized based on assumed load," Cornish says. "If you know what actual coincident load is, you can do a better job of sizing and locating equipment."

King also notes that utilities with detailed metering data don't need as large a reserve margin in distribution system planning. He is familiar with one Northwest utility that shaved 40 percent off its next year's budget for distribution assets because accurate load data allowed the organization to defer purchases. On an ongoing basis, the utility estimated it could save up to 13 percent over investments made before it had advanced metering data. Other data benefits utilities are finding include:

LOCATING ASSETS

John Bruns, manager of engineering and technology at White River Electric Cooperative in Branson, Mo., relies on data from his TWACS by DCSI metering system to see where loads actually occur on feeder lines. "Let's say I have a feeder that goes 10 miles out of a substation," he says. "I want to know exactly where its load is. Is it in the first couple of miles? At the end of the line? Once I know where the load occurs, I can put regulators and capacitors in the proper place. That cuts down on quality problems and line loss."

LOAD BALANCING

Bruns also uses his AMR data for load balancing because the system delivers data on true phasing at each meter site. "We can go through and balance loads on A, B and C phases easily," he says. "We know exactly which customers we need to move from one phase to another." This, too, cuts the utility's line loss.

CAPACITOR BANK SWITCHING

As load climbs, voltage generally goes down a little, and utilities boost it via capacitors. "You want capacitors on mainly during peak hours," King says. "Otherwise, they're sucking energy out of the system unnecessarily." Without communication to control capacitors, utilities must use thermostats or time

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METERING
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clocks. "Time clocks get out of sync over the years, turning on and off at the wrong time. Plus, they over compensate," says King. Thermostats can be problematic as well.

During the early to mid 1990s, Kansas City Power & Light replaced thermostat controls on 800 capacitors with Intelligent Electronic Devices (IEDs) equipped with two-way radios that the utility can control via its CellNet AMR system. The result? Significant savings accrue from deferred investments, more effective equipment location, reduced line losses and eliminated maintenance tasks. (See prevous issue: "Automation Plus Remote Control Pays Off for KCP&L.")

INCIDENT RESEARCH

Although Puget Sound Energy is just now gearing up to do load analysis with AMR data from the 1.6 million meters it reads with a Cellnet system, the utility is finding other operations perks. One is ad hoc research.

"We've done transformer load research for claims," says PSE's John McClaine, manager of metering network services. As an example, he cites a housing development where all the newly built homes were supposed to have gas heat, so the utility put in 50 kilowatt transformers to serve the expected load of homes that didn't rely on electricity for heating. During construction of the new development, an overburdened transformer blew.

"The developer brought in a bunch of electric heaters while drywall was being installed in houses," McClaine says. "Then when we tried to charge the developer for the transformer, they said we'd undersized it. We hadn't. It was sized for what the developer said the load would be." Meter data showed the load exceeded expectations—and capacity.

McClaine also uses AMR data to find possible tree-trimming troubles. His system sends last gasp transmissions from each meter when the meter loses power. With radio signals stepping on each other, only about 7 percent of those transmissions get through in a widespread outage. But almost all the power-up transmissions the meters send when power is restored get through because the meters send that message up to 18 times over a 45-minute time period.

This leaves PSE with an "excessive restorations" report. Because both the last-gasp and power-up messages come from meters losing power for as little as a tenth of a second, the excessive restorations report spotlights blinks, or problems that could represent fault current caused by tree limbs brushing the lines.

"Excessive restorations identify potential problems," McClain says, but he adds that utilities must translate the information excessive outages relay. "Our emergency operations people don't want to hear about momentary outages," he says. "They want to know when people are really out of power."

LESS LOSS

King sees another investigative use of advanced metering data: investigation

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ANNUNCIATOR TARGET RELAYS (ATRS)

Microprocessor-based Annunciator Target Relays (ATRs) are used to replace electromechanical annunciators to identify the source of an incoming trip signal quickly (microseconds). Developed in response to industry demands to replace older relays that could not keep up with modern high-speed LORs, these compact, reliable solid-state units offer adjustable trip-response times and can accept an input signal from a variety of devices. In a standard 3-hole panel installation, an ATR can (A) illuminate a bright LED to indicate a trip event and (B) send signals to activate up to two other devices within the system, such as alarms or other relays. Once a trip signal has been detected, the two auxiliary contacts either latch or slave to the source, depending upon model. The LED will stay lit until the reset button is pushed.

TAGGING RELAYS (TRS)

Worker-safety Tag-Out rules require the placement of a warning tag on every switch that could be used to energize a piece of out-of-service equipment being maintained or repaired. Modern Tagging Relays allow a remote operator to place and remove such tags, thus optimizing automated breaker control schemes in new or existing power distribution systems. Recently available with serial communications capability for network control, TRs can control remote reclosure cutoff and facilitate the expansion of a remote control SCADA system beyond a substation to distribution feeders. These compact units have multiple contacts and are available with two or three positions. Two-position models offer "Normal" and "Tagged" positions, while three-position models have "Closed," "Open," and "Tagged" positions. The best models allow bi-directional operation.

CONTROL INDICATOR MODULES (CIMS)

"A breaker control panel in a box" is what some call the versatile Control Indicator Module. Designed for highly automated environments, this device works with RTU points or serially, using MODBUS, DNP3, or other communications protocols. It enables an electric utility to trip and close a station breaker as well as monitor up to three trip coils for continuity. The unit also replaces the SCADA interposing relay, accepting signals from protective relays to control breaker function. Switches on the unit's front panel permit manual control of breakers and reclosers even during software failures. Time stamping provides a precise record of recent events. The CIM can communicate directly with up to 32 separate computer workstations, printers, etc. through its RS-485 interface. A simple 8-bit parallel interface is also available. The CIM's front panel contains red, amber, and green LEDs that indicate breaker trip coil operation, trip signals and their sources, and the status of both the external reclose relay and the interface to the supervisory control system. Taking up less than 13 square inches of panel space (either horizontal or vertical), the unit is easily incorporated into a new or existing substation and is compatible with virtually all other electronic or electromechanical protective equipment. The CIM meets IEEE standards C37.90.1 and C37.90.2.

INSTRUMENT AND CONTROL SWITCHES

Often, Instrument and Control Switches can be easily replaced by SCADA-compatible units providing both remote and manual operation. A worn or failing switch that is no longer manufactured can be replaced with a switch that performs the same manual function as the original (often in the same mounting footprint) while adding compatibility with modern supervisory control systems.

"SMART NAMEPLATES"

Another development worth noting is the availability of "Smart Nameplates," which are especially useful at hybrid substations in transition from manual to automated operation. Whether a control switch is operated manually or remotely, critical warning and status information is still best presented through panel-mounted indicator lamps. The most common lamp applications are local indication of breaker status, trip coil integrity, and LOR trip signal detection, each traditionally monitored with separately mounted incandescent bulbs. The "Smart Nameplate" incorporates these functions into the pertinent switch or relay itself.

By utilizing very bright, low-power light-emitting diodes (LEDs) "Smart Nameplates" match the candlepower of the brightest incandescent bulbs while saving energy, heat, and panel space. They monitor and annunciate faults so economically they eliminate the need for a separate coil monitor relay or system voltage monitor. Better yet, they are equipped for SCADA-compatible remote annunciation of critical functions by way of solid-state dry contacts. A standard-size nameplate can contain up to three indicator LEDs and one output contact, monitoring and displaying the status of multiple events and triggering annunciation or device activation. These nameplates are available with or without mechanical targets.

A "Smart Nameplate" for an LOR, for example, monitors the integrity of the LOR trip coil and the presence of a trip signal.

The all-important "health" of the LOR trip coil, which translates the input signal into the change-of-state of the LOR contacts, is effectively monitored by internal circuitry that trickles a pilot current through the coil and lights an LED at the top left of the nameplate. This unmistakably bright LED gives local indication that the coil is intact and ready to operate. Should the coil burn out for any reason, the LED extinguishes and an on-board solid-state contact (100mA/125VDC) closes, allowing SCADA-compatible remote annunciation.

Additional circuitry in the LOR "Smart Nameplate" is designed to further protect the coil by preventing the most common failure mode: an operator resetting the LOR into a standing trip signal and heating the coil to failure. As long as the trip signal is present at the coil inputs, a second LED glows to warn against resetting. Only when the trip signal is removed does this warning LED extinguish, indicating it is safe to reset the LOR.

When adapted for breaker control, the "Smart Nameplate" can be mounted on a standard manual control switch or a remotely operable, SCADA-compatible Control Switch Relay. In this application, one, two, or three LEDs are arrayed across the top of the nameplate for easy visibility, typically indicating breaker status (open/closed) and/or breaker trip coil integrity.

Recent improvements in LED technology have produced long life (100,000+ hours vs. 2,000 hours for

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ELECTRICAL CONSIDERATIONS FOR TELECOMMUNICATIONS

By Dale Budenski, SR RCDD MEC, The Wiremold Company

Plain old telephone service (POTS) just doesn't cut it in a high speed digital world. The same can be said for plain old electrical service (POES). The electrical systems that were adequate in buildings constructed even just a few years ago were not designed to support sophisticated electronic equipment and integrated building systems.

The threats from electrical disturbances are greater than ever. And the costs are higher. One conservative estimate places the cost of damage to equipment and network downtime in excess of $26 billion per year.

This means that telecommunications designers must take a proactive approach to coordinating a complete plan for protecting building systems and networks against electrical disturbances. This idea sometimes takes a back seat to other considerations, but BICSI TDM 9 states the case very clearly:

"Before incorporating telecommunications into the construction plans, a telecommunications distribution designer must possess an essential awareness of the prospective client's communications needs and wants. The designer must carefully consider voice, data, and video communications; building automation systems; and electrical power into, out of, and within the property."

A COMPREHENSIVE APPROACH

Today, the electrical system must fully support voice/data/video (VDV) in a coordinated fashion because VDV is now on a par with the "big three" of building systems: mechanical, electrical, and HVAC. In fact, because these systems are interconnected and rely to a great degree on electronics, they will not function optimally - and may not function at all - with an inadequate POES that is prone to electrical disturbances.

Consider the various systems that make a typical building function:

Networks
Telephone riser
Fire alarm riser
Security riser
Building management system riser
Closed-circuit TV riser
Satellite TV riser
Power riser

Note that these systems intermesh and interconnect. To cite just one example, the fire alarm control panel connects to the main power, the telephone system, elevator controls, door controls, and other systems. Computer networks and building systems must be protected against electrical disturbances.

ELECTRICAL DISTURBANCES

What are electrical disturbances? One popular image is a bolt of lightning and a computer blowing up. Another is a total blackout. While such events qualify as electrical disturbances, there is more to be concerned with. The vast majority of these disturbances are transients, surges, spikes, and noise.

Surges result from a variety of causes inside and outside a facility. External causes include lightning and power line switching; internal surges are generated by equipment motors and office equipment like copiers and printers. Studies show that 70 percent of surges originate within a building. Catastrophic surges, such as lightning strikes, can cause immediate disruption of data and damage to sensitive equipment. Far more common, however, is latent damage and gradual degradation of electronic equipment that results from the cumulative effect of smaller, internal surges.

Noise results from switches, tools, and lighting, as well as EMI/RFI and poor grounding techniques. Noise has the potential to disrupt data and cause latent damage to hardware.

Over-voltage can be caused by generator or utility faults, proximity to substations, and sudden load decreases. This condition, which lasts for more than half a cycle, should not be confused with surges, which are measured in milliseconds. High voltage, sometimes called "swell," can damage equipment.

Under-voltage occurs during heavy demand on utilities and when heavy loads are introduced. Low voltage, also known as "sag," can result in equipment shutdown, overheating or failure.

Blackouts result from utility failure or circuit overload. Consequences include loss of unsaved data and potential hardware and software damage.

The above disturbances are all characterized by their unpredictability. Another disturbance is harmonic distortion, which predictably develops as a result of nonlinear loads, rectifier loads, and switch mode power supplies. Harmonics can lead to overheating of neutrals and transformers, insulation breakdown, and fire.

PROTECTING ELECTRICAL SYSTEMS

A properly designed electrical system can withstand all threats. A "POES" cannot. A zoned, "whole building" approach to power and data quality is a comprehensive, coordinated solution that protects an entire building from sources both outside and inside the workplace by separating it into strategic zones, and protecting these zones with surge protection devices.

Zone 0 is the outside environment where power disturbances from lightning, radio frequency signals, and utility faults originate. This zone is out of the control of equipment located within a building.

Zone 1 is the main service entrance. Because incoming cables carry the most severe threats, surge protection devices must be installed on all service entrance cables. Metallic conductors, like conduits and water pipes, should be connected to a common ground point, and all surge protection devices should be grounded to the same electrical ground.

Zone 2 represents distribution panels or sub-panels, where supplemental layers of protection address disturbance remnants from the protectors at the service entrance, as well as any power quality problems created within the facility. Surge protection devices provide bi-

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SUBSTATION

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incandescent bulbs) and impressive resistance to vibration. The newest generation of LEDs has come to market in a variety of brilliant colors, each capable of producing more light than older devices by at least an order of magnitude. Today's LEDs emit light over a wide viewing angle, so they are visible when seen from the side, even under the brightest ambient lighting conditions.

In other words, the "Smart Nameplate" brings many advantages to the modern control panel:

- Visibility — extraordinary brightness from all viewing angles.
- SCADA-Compatible Annunciation — solid-state dry contact linked to LED.
- Backward Compatibility — retrofit kits available.
- Long Life — LEDs rated for 100,000+ hours.
- Easy LED Replacement — socketed LEDs removable from front, without disturbing wiring.
- Low Power Consumption — less than 12 mAmp per lighted LED.
- Self-contained — all current-limiting and remote-annunciation circuitry included.
- Five Brilliant Colors — green, red, amber, blue, and white available.
- Space Savings — up to three LEDs inside the standard nameplate footprint.
- Low Cost — save on initial cost, wiring labor, and replacement intervals.
- Built-in Terminal Block — extra switch deck provides termination for leads.

In the midst of all this talk about high-tech features, it is reassuring to note that all these switches are still available with handles fashioned into familiar shapes for human hands — oval, knurled, and pistol-grip.

The best of today's switches and relays have low-resistance contacts and other features that enable them to work well with automated supervisory control systems, yet they permit an on-site operator to quickly take over if computers fail, even in brownout conditions. When nobody is present, a substation can be monitored and operated remotely. And if the devices that facilitate this are, at their cores, still the same proven devices the industry has depended upon for a century, so much the better.

REDUNDANCY IS GOOD, MANUAL BACKUP IS PARAMOUNT

Summing up, automation should not mean the elimination of easily accessible manual control. Using cost-effective devices that bridge the analog/digital gap to upgrade equipment does not require a choice between complete remote operation and manual capability. Versatile products are available today to provide the best of both worlds. As substation equipment continues to evolve, the human safety element should not be neglected along the way. Reliable products retaining safe and easy manual operation make welcoming new technology a net gain, not a trade-off.

Jeff Rogers is a Regional Sales Manager for Electroswitch, a leading supplier of rotary switches and relays to the utility, industrial, military, and electronics marketplaces.

METERING

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of excessive line loss. Noting that U.S. utilities lose about 7 percent of generation or $14 in line loss annually, King maintains that even cutting losses by a small percentage could have big-dollar implications.

"With detailed data, you can have simultaneous reads across your system at one point in time," he says. "Then you can aggregate circuits, find the ones that have high loss and investigate. You might fine a phase that's not being metered on a polyphase customer or faulty grounding that has you losing power to the ground."

Although King notes that no utility has done such research in any detail, he feels the savings potential is significant. "Many utilities look at benefits like this and put a very small value on them," he says. But he also maintains that it pays to examine all the possibilities advanced metering delivers. "One Midwest utility saves more than $2 million every year just on load balancing and transformer load management alone."

KEEPING THE DATA COMING TO KEEP THE POWER FLOWING

By Don Horne

Power interruptions translate into lost dollars, and software systems designed to ensure power quality and reliability are no longer luxuries but vital necessities.

Control Microsystems out of Ottawa, Ontario has introduced ClearSCADA, an automation software platform for gathering, processing and relaying information in real-time while providing powerful system visualization, data acquisition and supervisory control.

"For municipal utilities, it is all about delivering product - and that is electricity," says Steve Goodman, VP of marketing with Control Microsystems.

"As it is based on a highly stable platform with scalability, it can scale with the utility as they grow," adds Mr. Goodman.

Coupled with the company's SCADAPack controllers, ClearSCADA offers monitoring and control functions with millisecond resolution.

"ClearSCADA can help eliminate downtime, distribute power more efficiently and provide the detailed audit trails necessary for today's modern distribution systems," says Dale Symington, Senior Vice President of Engineering for Control Microsystems.

> "For municipal utilities, it is all about delivering product - and that is electricity,"
> - Steve Goodman

It also features built-in system redundancy, scalability, and increased security control. The new SCADA (Supervisory Control and Data Acquisition) platform integrates seamlessly with Control Microsystems' controllers and is based on open interface and protocol standards for use with third-party hardware.

Control Microsystems' products are used by system integrators and end users in oil & gas production automation applications, municipal water and wastewater systems and electrical power applications.

ClearSCADA was the fruit of an alliance between Control Microsystems and Australia's Serck Controls, who developed SCADA for TransGrid, the principal operator/manager of the high voltage transmission system for New South Wales, Australia.

"The heritage of ClearSCADA is the SCX6 system developed by Serck Controls," points out Mr. Goodman. "We took that technology and got it ready for the North American market. We are confident about the product, as it is a very modern software system."

In the Australian system, TransGrid replaced half of their existing RTUs (Remote Terminal Units) at 44 transmission substations and replaced alarm panels at 14 substations with IEDs (Intelligent Electronic Devices) and PC-based HMI (Human Machine Interface). Key substation automation components included data concentrator (dual redundant at some sites) Control IEDs, Alarm IEDs, Ethernet switches and Serck SCX HMI.

Apart from the SCADA functionality requirement in the substation environment, the TransGrid control system architecture requires the HMI to access and extract data directly from IEDs and protection relays within the substation and present this data on the HMI.

"ClearSCADA has PNP3 (plug and play), a protocol that is used extensively in the industry," says Mr. Goodman. "It is a very user-friendly system."

For more information on ClearSCADA, you can log onto the Control Microsystems website at: www.controlmicrosystems.com.

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directional protection from internally-generated surge activity migrating onto critical branch circuits.

Zone 3 includes points of use or workstations, where each piece of equipment, such as a computer, telephone, or fax machine, should have separate protection to safeguard against ground potential differences.

There are three basics to achieving protection against electrical disturbances in a network environment:

A surge protection device with a clamping level of 400V at the main service panel.

A panel-mount surge protection device (330V clamping level) for each network.

If one node on a network has a plug-in surge protection device, then all nodes must be protected.

The device at the panel reduces potentially catastrophic surges as they enter the building. The panel-mount device further reduces the potential for damaging surges. But protecting some, but not all network devices leaves the door open for damage, even if there are surge protection devices at the main and sub-panels.

When a surge reaches the protection device on a computer, it will be diverted to the computer chassis's ground. However, the network data line connects to a network interface card with an input chip that is referenced to the chassis ground. The result is a sizable voltage potential difference between the chassis of the protected computer and the downstream, unprotected computer. The network interface card tries to equalize the voltage and the chip burns up. Placing surge protection devices on all computers in a network eliminates this problem by allowing the voltage potential difference to always remain at zero.

Similar issues can occur with surge protection at the server. The root of the problem is confusion about the difference between an uninterruptible power supply (UPS) and a standby power supply (SPS). A true UPS continually provides power to the protected equipment with no break in the supply of power. An SPS, on the other hand, provides power but with a very short delay, typically referred to as "transfer time." Under normal power conditions - that is, excluding a blackout - an SPS functions as a surge suppressor. And if other network components are not protected, the SPS at the server can create a damaging voltage potential difference.

Multiple building "campus" environments with copper network backbones have the additional consideration of resistive coupling. Networked buildings present the risk of a large voltage potential difference across the distance between buildings in the event of lightning. Fiber optic backbones are, of course, not subject to this phenomenon.

OTHER PROTECTION DEVICES

Power conditioners provide clean, stable, isolated power by eliminating the damaging effects of surges, noise, over-voltage, under-voltage, and harmonics. The only problem is that they do not guard against blackouts, which constitute less than one percent of power problems. Isolation transformer, ferroresonant line conditioner, and automatic voltage regulator are terms that are often mentioned in the field of power conditioning. Despite the fact that they are all varieties of transformer, they are not the same and do not offer the same benefits. An isolation transformer generally isolates the load on the secondary side from the source on the primary side in conjunction with an electrostatic shield between secondary and primary windings. Its main function is to suppress common mode noise on the secondary side of the transformer.

An automatic voltage regulator provides voltage regulation through tap changing transformer technology. These devices provide regulation by "tapping" the output voltage up or down based on changes to the input voltage. Automatic voltage regulators usually also contain devices for surge protection and noise filtering, but they do not provide any harmonic containment.

Like an automatic voltage regulator, a ferroresonant power conditioner provides voltage regulation, noise filtering, and surge protection. However, they also offer excellent harmonic containment by producing a finely tuned circuit which only resonates at a specified frequency, usually 60 Hz. Therefore, changes on the input are not reflected on the output, and vice versa. As a result of 60Hz resonance, only 60Hz is allowed to be deflected back on the building's distribution system. These inherent characteristics make the ferroresonant transformer an excellent harmonic containment device.

CO-ORDINATION IS CRITICAL

As recently as 20 years ago the typical desk had a phone serviced by POTS and a typewriter or calculator that plugged into a POES duplex receptacle. Today's desk looks a lot different, and today's telecommunications and integrated building systems can't function with yesterday's electrical system.

FREQUENCY RESPONSE ANALYSIS OF POWER TRANSFORMERS: PRACTICAL ASPECTS OF FRA TESTING AND INTERPRETATION

By Jeffrey A. Britton and Miles Dowiak, Phenix Technologies

What is Frequency Response Analysis (FRA)?

Frequency Response Analysis, commonly abbreviated by test engineers and technicians as "FRA", has long been recognized as a powerful testing tool for detecting winding displacements caused by transportation damage, short circuit current forces, or loosening of winding clamping pressures [1]. Sophisticated new test techniques are improving sensitivity, repeatability, and interpretation of results by overcoming the practical measurement and interpretation issues that have limited the usefulness of FRA as a viable testing tool in the past, especially in frequency ranges above 2 MHz.

FRA testing theory follows from the fact that the impedance, or conversely the admittance of any RLC network, changes as a function of frequency. Any power transformer may be represented by a complex network of resistances, inductances and capacitances. The simplified schematic diagram of such an RLC network, shown in Figure 1, may be used represent the high voltage winding of a typical power transformer. The impulse source and measuring shunt represent components of a generic impulse based FRA test system.

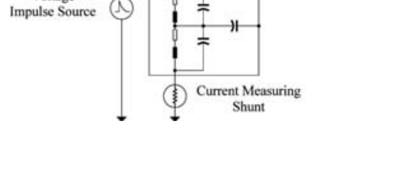

Figure 1: Schematic Diagram Representing the HV Winding of a Power Transformer, with Voltage Impulse Source and Current Measuring Shunt Connected

The electrical value of the components comprising the equivalent circuit is a function of the mechanical geometry inside the transformer, as well as the electrical properties of the insulating materials used in the construction. Any change in these values will result in a measurable shift in the frequency response. The frequency response, sometimes referred to as the transfer function, of any RLC network is a complex function, having both a magnitude and phase angle at each frequency. An example of a typical power transformer frequency response plot is shown in Figure 2, including both magnitude and phase angle.Any movement of the core and / or winding assembly inside the transformer will result in changes in the values of inductance and capacitance shown in the equivalent circuit of Figure 1, and a corresponding shift of the frequency response plots shown in Figure 2. The peaks in the transfer function magnitude plot represent internal resonant frequencies within the transformer, and these peaks may shift up or down in frequency, or peaks may appear or disappear from the response, depending on the severity of changes that have taken place within the transformer. Even minor changes to the geometry may appear as significant shifts in the frequency response plots, especially for resonant peaks occurring at frequencies above 2 MHz.

Degradation of the dielectric properties of the high voltage insulation will result most notably in reductions in the amplitude of the peaks in the transfer function magnitude plot. Physically, this can be explained as increased damping of the internal resonances, based on a high leakage current flowing in the insulation. Again, this effect is more pronounced in the upper frequencies, underscoring the importance of a highly accurate and repeatable method of measurement across the entire frequency range of interest.

Based on the above physical explanation, as well as practical experience, an FRA test is the most sensitive testing tool developed to date for detecting physical movements in the core and/or winding assemblies within a power transformer.

MOTIVATIONS AND OBJECTIVES FOR MAKING FRA MEASUREMENTS ON POWER TRANSFORMERS

The motivations for making FRA measurements on power transformers, as with any type of diagnostic testing and monitoring, are straightforward. The first and most important is increased system reliability, and a corresponding reduction in downtime costs that result from in service equipment failure. Secondly, a reduction in system maintenance costs may be achieved through better targeted maintenance efforts. Through the proper use of FRA diagnostic technology, units may be operated longer between major scheduled maintenance shutdowns. Finally, FRA testing allows better use of aging utility assets. All utilities want to get as much life out of their major components as possible. In today's power system, it is common to find transformers that have been in near continuous service for forty years or longer. FRA can serve as a valuable tool for the test engineer and asset manager in determining when an older unit may continue in service with minimal risk of failure, or conversely when an older unit is becoming an unacceptable reliability risk. This information, if acted upon, may be used not only to avoid an in-service failure, but also to extend the life of valuable power system assets.

The objectives for performing FRA measurements are twofold, and are stated

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in the following questions:

1) How can a repeatable transfer function be obtained through practical measurement techniques?

2) Once the FRA result is obtained, how can it be interpreted to explain what it means for the transformer?

The remainder of this paper will attempt to answer these questions, with emphasis on newly developed techniques for improving the repeatability, sensitivity, and interpretation of results.

USING FRA TO ENHANCE THE EFFECTIVENESS OF AN OVERALL TESTING PLAN

FRA testing offers a new tool with the sensitivity to detect several conditions that are often difficult or impossible to detect using traditional testing methods. Winding movements often occur as a result of transportation damage, or short circuit current forces resulting from subjection to a low impedance fault while in service. Even though the degree of movement may not be significant enough to produce a notable shift in the short circuit impedance or capacitance measurements of the transformer, the short circuit mechanical withstand strength of the winding assembly may be compromised, resulting in an increased risk of failure in a subsequent fault. FRA has in fact been shown to have the ability to detect winding looseness, providing that some axial elongation has taken place, even if no radial deformation has occurred. The specific information received from an FRA test may therefore serve as a notification that winding clamps need to be tightened before another fault occurs that may result in a complete mechanical failure.

Problems in tap changer windings or contacts are easily seen as significant shifts in the frequency response. Additionally, degradation of insulation resulting from prolonged partial discharges in windings or bushings will show up in an FRA response, as the capacitive and resistive characteristics of the insulation are affected. Even though insulation damages may be locally severe enough to result in premature electrical failure, such damages are often difficult or impossible to detect using traditional power frequency tests, such as insulation power factor (Tan ?). These effects often appear as shifts in the FRA response at frequencies of 2 MHz and higher. In order to see these effects, it is therefore recommended that the measuring technique demonstrates a high degree of sensitivity and repeatability up to a frequency of 5 MHz.

Core related problems in power transformers can usually be divided into two main categories; mechanical or structural (usually resulting from excessive transportation shocks), and electrical (usually resulting from a failure of low voltage frame to core insulation used to control circulating currents in the core and surrounding frame and tank structures). Core assemblies in modern power transformers rarely experience mechanical or structural failures, as the core assembly is well supported inside the tank through the use of extremely rigid frame structures. This being said, if a transformer was to experience a transportation shock severe enough to result in core movement, the corresponding winding movement would appear as a significant shift in the frequency response. Experience shows that electrical problems that result from a failure of low voltage core insulation are easily revealed by traditional low frequency tests such as an excitation current measurement. For transformers that have been in service for some time, core insulation problems that have resulted in any significant overheating of steel components will result in elevated levels of combustible gasses appearing in the periodic dissolved gas analysis results. In short, while FRA may be used to detect core damage, other more traditional test techniques are more sensitive, and can still provide more specific information regarding core related problems.

As with all diagnostic testing, choosing the correct testing tools is perhaps the most important part of developing an effective testing plan. This means that sometimes FRA alone is not the best test strategy. The most effective diagnosis usually results when the test engineer makes use of all available information to try to recognize a trend, or to look for a possible common problem that is consistent with results obtained from different tests. Due to its high sensitivity to minor changes occurring within the transformer, FRA will often be the first test to clearly indicate that something has changed inside the transformer, even though the results of other tests, at first glance, may not appear significantly different than before. Once the FRA test result tips the test engineer off to a potential problem, other test results may be examined more closely to assist in specific diagnosis. At this time, FRA results should be combined with a closer analysis of historical test results for dissolved gas analysis, insulation power factor (Tan ?), capacitance, impedance measurement, excitation current measurement, and turns ratio measurement. In the absence of other supporting test data, a visual inspection may be employed to look for displaced windings, inspect blocks and clamps for proper tightness, or look for evidence of arcing damage. Therefore when an FRA test indicates a potential problem, the best diagnosis comes when the FRA test result is viewed in combination with all other available information.

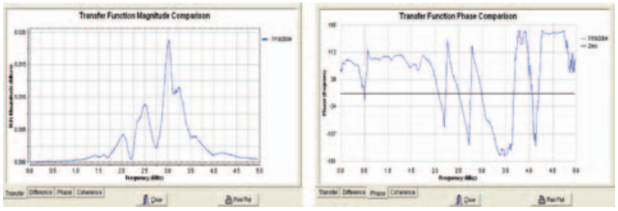

Figure 2: Examples of Typical Frequency Response Plots for a Power Transformer, Including Magnitude (left) and Phase Angle (right), as a Function of Frequency

HISTORY AND PREVIOUS APPLICATION OF FRA IN POWER TRANSFORMER TESTING

The idea of using FRA to monitor the condition of critical power transform-

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ers running in the transmission and distribution network is not a new one. The knowledge that the AC impedance (or admittance) of any RLC network is a function of frequency is almost as old as the discipline of electrical power engineering itself. The realization that the impedance (or admittance) versus frequency characteristic of certain critical power system equipment might be used as a diagnostic tool to assess the electrical and mechanical condition of the equipment is a newer development.

Over the past 30 years or so, much work has been done to try to understand how to first obtain and then to use the powerful information contained in the frequency response.

Unfortunately, the large physical dimensions of the test circuit present a challenge to making good (repeatable) high frequency measurements. Many potential users have been discouraged over the years through the apparent lack of repeatability when attempting to measure the high frequency response (above 1 MHz) of large power transformers, when in fact the problems stemmed fully from poor high frequency test and measurement technique. Making correct high frequency measurements require consistency in test connections, and a good understanding of how the test equipment itself affects the frequency response of the test object.

There have been two basic methods used in the past to measure the frequency response of power transformers. The first, known as the swept frequency method, makes use of the simple truth that the sinusoidal AC impedance (or admittance) of a transformer winding varies with frequency. Traditionally, a network analyzer is used to apply a sinusoidal AC voltage to one terminal of the transformer, while the resulting response current is measured returning from another terminal, via conversion to a voltage at the 50 ohm input to the network analyzer. The frequency response is directly measured as the admittance (magnitude and phase angle) of the winding, as the frequency is swept through the full range of interest. The basic setup for a swept frequency FRA measurement is shown in Figure 3.

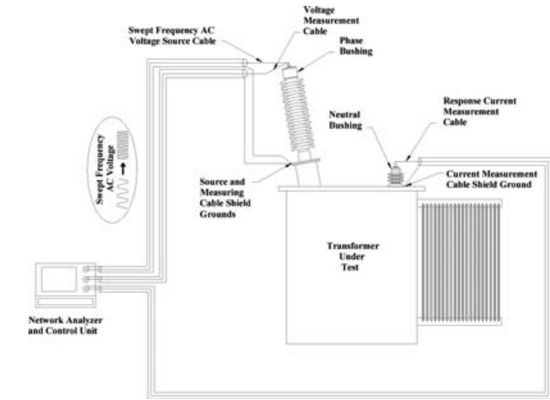

Figure 3: Basic Setup for the AC Swept Frequency FRA Test Method

From an intuitive standpoint, this is the most easily understood means of measuring a frequency response. There are however some serious practical difficulties associated with this technique when it is applied to large power transformers. These measurements have traditionally been made using a network analyzer that applies a low amplitude AC voltage (10 volts for example), to the test object. At very low frequencies (in the range of some hundreds of Hz to low kHz), these instruments tend to lack sufficient power to excite a large power transformer, due to the heavy inductive load presented by the steel core. At very high frequencies (in the range of 2 MHz to 5 MHz), sufficient power may be lacking due to the heavy capacitive load presented by the capacitance of the winding insulation system. The resulting low signal levels in the response voltage may result in high measurement error, and poor repeatability. This problem is especially troublesome on transformer windings with low series inductive impedance, as commonly encountered on high current windings.

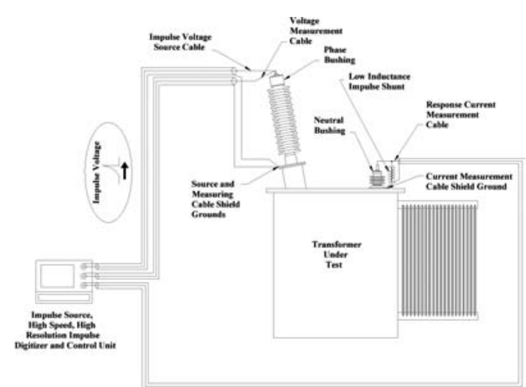

Figure 4: Basic Setup for the Traditional Low Voltage Impulse FRA Test Method

An additional limitation associated with the use of the network analyzer is that the response current must flow over the length of the measurement cable (usually 50 feet or more when connecting to large power transformer bushings) back to the network analyzer, where it is converted to a voltage via the 50 ohm input impedance of the instrument. This technique by design inserts the current measuring cable impedance in series with the transformer winding under test, thereby making the result highly dependent on the particular length and characteristics of the cable. In addition, the relatively high 50 ohm impedance significantly damps the high frequency portion of the FRA response. The result is poor sensitivity in the upper frequency ranges, and poor repeatability whenever the test is repeated with different measuring cables. In some cases, the true frequency response of the transformer above 2 MHz may be completely attenuated by the limitations associated with the measurement technique.

The second method makes use of Fourier analysis to arrive at a transfer function through the results of a series of low voltage impulse tests. The basic setup for this test is shown in Figure 4. In this technique, a series of low voltage impulses are applied to one terminal of the transformer under test, and the resulting current is measured directly at the transformer by means of a voltage developing, low inductance impulse shunt connected in series with the other terminal.

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The value of the shunt is selected to provide adequate measuring sensitivity, while avoiding introducing excessive damping to the high frequency response. Through experience, a value of 10 Ω has been found to be adequate. The impulse amplitude typically ranges from tens of volts to several hundred volts, with a maximum rise time that corresponds to 1 divided by the highest frequency to be considered in the FRA. This means that for a frequency response up to 5 MHz, the exciting impulse must have a rise time of less than 200 ns. Test circuit ground is considered to be the tank of the transformer under test.

The traditional technique is to measure and record the exciting impulse and the resulting response current using a digitizer with sufficient amplitude resolution (generally accepted as at least 9 bit, or 1 part in 512 resolution), and sufficient sampling rate to preserve the highest frequency to be included in the frequency response. Once the time domain record of the voltage (input) and current (output) are recorded, the transfer function is calculated as the Fast Fourier Transform (FFT) of the output divided by the FFT of the input.

The great strength of this technique is that the applied voltage and resulting response current are physically measured at the transformer. This method is therefore minimally intrusive as far as the impact that the measuring cables have on the true impulse response of the transformer, as long as a proper, repeatable, low inductance connection is placed from the response current measuring terminal to ground.

Although this method has the potential to produce a much better representation of the transformer's true frequency response, there are again several practical problems with the application of this technique which make it difficult to achieve repeatable results. Chief among these is the sensitivity to noise influences that may have a drastic effect on the transfer function result. In order to reduce the influence of noise, the traditional approach has been to average the results of a series of applied impulses (for example up to 100 impulses) in the time domain, and then perform the FFT on the time domain averaged results. It turns out however that the resulting frequency response produced by this method of time domain averaging is very sensitive to even minor time domain differences in the impulse wave shapes. Achieving repeatable results using this technique has therefore necessitated the use of expensive impulse source equipment, capable of producing a series of precisely repeatable impulses, both with regard to wave shape and time between applications. The traditional low voltage impulse method therefore, while having some distinct advantages over swept frequency, is not easy to apply in a way that repeatable results can be achieved, especially in noisy field environments.

Interpretation of FRA results has historically been highly subjective, with a high degree of expertise required to judge whether a difference in FRA results is detrimental to a transformer. There is little to say on this subject since little progress has been made on the interpretation question until very recently. When comparing two frequency responses, the general approach has been to look at the location (frequency) of the resonant peaks in the frequency response magnitude plot. Shifts in frequency of a particular resonant peak, or the appearance or disappearance of peaks in the frequency response at a particular frequency represent cause for concern. It has therefore required the experience of an engineer in interpreting FRA test records to make a judgment as to whether a difference is significant enough to merit further testing and inspection of the transformer prior to energization in the network.

NEW DEVELOPMENTS IN FRA TESTING TECHNIQUES AND INTERPRETATION

Modern computational software packages and the emergence of high speed, high resolution, low cost digitizers have made sensitive, high quality FRA measurement much more achievable than in the past. A patented new technique based on Spectral Density Estimate calculations has been developed by the National Electrical Energy Testing Research and Applications Center (NEETRAC), a center of Georgia Institute of Technology, provides both the possibility of a highly repeatable FRA result, as well as an objective software evaluation package to assist in interpreting the data gathered [2] [3] [4] [5].

The new technique is based on the traditional low voltage impulse method, which best preserves the frequency response of the transformer itself, as compared with the swept frequency method. Although the test voltage type (impulse) and the test connections are the same as those used in the traditional impulse method, the method of calculating the transfer function is completely different. The quality and repeatability of the results show great improvements over past techniques. The key points of the new method are listed below:

- Individual impulses are applied, with each impulse and its resulting response current recorded as a time domain signal, for a series of ten impulses per winding connection.
- An auto spectral density estimate (SDE) is computed separately in software for each of the ten voltage and current pulse pairs recorded. In addition, a cross SDE is computed for each voltage / current pulse pair. These SDEs may be thought of as a representation of the power present in the measured impulses, as a function of frequency.
- Once ten pulse pairs have been acquired and their respective auto and cross spectra computed, an average frequency domain SDE is computed over the ten pulses acquired.
- The frequency response is calculated as the ratio of the average cross spectra to the average auto spectra.

Averaging is still employed in this technique to reduce the influence to noise and random error, however applying the averaging after the transformation to the frequency domain effectively removes the sensitivity to variations in the time domain impulse records. This was the greatest limitation of the traditional low voltage impulse method. The dramatically improved high frequency repeatability and noise immunity offered by this new approach have been applied to take advantage of the high frequency sensitivity that is inherent to the low voltage

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impulse method. The resulting test technique offers a higher sensitivity to even modest changes that have occurred inside the transformer.

The lack of any objective comparison between two transfer functions has traditionally been one of the primary limitations associated with all diagnostic FRA techniques. A method of evaluating the difference between transfer functions has been developed at NEETRAC that provides a single condition number or Weighted Normalized Difference (WND) to quantify the difference between any two transfer functions being compared. The key points of the WND calculation are as follows:

- The arithmetic difference between transfer function magnitudes is computed at each frequency.
- Each data point is normalized.
- Each data point is weighted according to an error function at that frequency.
- WND = a constant times the average of the weighted values.

The error function is based on a coherence function calculation that estimates the linearity of the transfer function result at each frequency [6]. This information is used to devalue the contribution to the total WND number in frequencies where a poor input to output coherence is recognized. The WND numbers have been divided into three ranges as shown in Table 1.

Table 1: WND Number Ranges, Relative to the Severity of the Change Detected

5 – 25	26 - 75	76 – 300
No Change Minor Change	Some Change	Significant to Major Change

These ranges have been established based on extensive development testing, and have proven to be good reference values for use in both field and laboratory tests, to indicate the significance of the winding deformation existing within the transformer.

An extension of the objective WND comparison is to look at the frequency response differences existing among the different phase windings of a three phase transformer. Experience has indicated that although a degree of difference is to be expected as a result of normal design and construction asymmetries, the frequency responses for the different phases of a three phase power transformer are related. This idea has led to the concept of Objective Winding Asymmetry, abbreviated OWA [7] [8]. In OWA analysis, the WND numbers are calculated in the same manner as presented earlier. The difference is that instead of comparing the frequency responses measured at different times for the same phase winding, frequency responses measured at the same time are compared across the individual phase windings of a three phase transformer. The OWA result is displayed as a percentage and is calculated for any three windings by averaging the highest two WND numbers, dividing the result by the lowest WND number, then subtracting one from the result and converting to percent.

OWA Comparison of WND numbers across phases has been shown to have the ability to identify individual windings that have shifted, even when no past FRA fingerprint is available for comparison. This is an enormous advantage when using FRA as a tool to assess the condition of an older transformer, where no historical data exists.

The OWA technique has also been shown to have significant value when comparing to historical data. In many cases, differences in the condition of the oil, or even differences in temperature can lead to differences in the transfer function that may be difficult to distinguish from differences resulting from mechanical or dielectric changes. In this instance, the phase to phase characteristics that are highlighted by the OWA analysis have proven to be much less sensitive to variables such as oil condition and temperature, owing to the fact that such changes affect the phase to phase comparisons equally at any given time, and therefore the overall effect of the change is cancelled out in the OWA analysis.

Through field experience gained by testing a wide range of power transformers, the OWA acceptance criteria shown in Table 2 has been established for three phase core form type transformers.

Table 2: OWA Acceptance Criteria for Three Phase Core Form Transformers Relative to Severity of Change Detected

Winding Set	No Change to Minor Change	Some Change	Significant to Major Change
Low Voltage "X" Windings	0-50%	50-100%	> 100%
High Voltage "H" Windings	0 – 100%	100 – 200%	> 200%

These criteria have been developed through analysis of field testing results on transformers ranging from approximately 4 MVA up to approximately 500 MVA. Different types of transformer designs require use of different acceptance criteria.

To summarize, modern objective FRA test strategies may include any of the following approaches:

- Objective comparison to a previous frequency response measured on the same transformer (phase by phase WND comparison to FRA fingerprint)
- Objective comparison of frequency responses measured on an identical sister transformer (phase by phase WND comparison to identical sister)
- Objective comparison across phases on a single transformer, when no historical data exists (phase to phase OWA comparison without historical data)
- Comparison of a previous phase to phase FRA to a present phase to phase FRA on the same transformer (comparison of present OWA to previous OWA)

The final analysis strategy listed above is in its early stages of development. It is expected that this analysis technique may provide the best ever sensitivity and repeatability, based on the inherent cancellation of the effects of normal test variables, such as temperature and oil condition, provided by the OWA test procedure.

REAL WORLD EXAMPLES OF TRANSFORMERS THAT HAVE BEEN FRA TESTED

Example 1: 42 MVA Three Phase Delta - Wye Power Transformer (Dielectric Problem)

This transformer was targeted for

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removal from the substation due to high acetylene appearing the periodic DGA. There was nothing outstanding on the field power factor test or the field internal inspection of the unit. However, the field FRA test indicated 358% OWA on H1H2 (center leg high voltage winding). The FRA also indicated 89.5% OWA on the High to Low coupling on the same leg, as seen in Table 3. Based on experience, the typical OWA without deformation for H windings is less than 100%. The typical OWA for H to L coupling without deformation is less than 60%. The transformer repair shop sent the LEG 2 coil assembly to the factory to be unwound to make a final determination on the source of the asymmetry and to find the acetylene source.

Table 3: Field Phase to Phase WND FRA test results on 42 MVA Transformer

H Phase Comparisons	WND	H-X Coupling Comparisons	WND	X Phase Comparisons	WND
H1H2-H2H3	391.6	H1X0-H2X0	143.9	X1X0-X2X0	128.1
H2H3-H3H1	91.0	H2X0-H3X0	160.0	X2X0-X3X0	140.5

Table 4: Field Phase to Phase OWA Results on 42 MVA Transformer

H1H2	H2X0	X3X0
358% OWA	89.5% OWA	7.5% OWA

Note that in Table 3, for each column of comparisons (H Phase, H-X Coupling, and X Phase), the winding that appears in common with the highest two out of three WND results is underscored in the table as the winding commonly associated with the highest phase to phase asymmetry. The resulting OWA for each column in Table 3 was calculated from the WND results listed, and the resulting asymmetries are listed in Table 4, under the winding commonly associated with the highest WND numbers in Table 3.

The OWA Results for the H winding FRA, and the H to X coupling FRA are far outside of the normal limits, suggesting a problem. Since the H1-H2 winding shows the highest asymmetry, and the H2 terminal is again associated with the highest asymmetery in the H to X winding coupling tests, a problem involving the H1H2 winding, located on the center leg of the transformer, can be suspected.

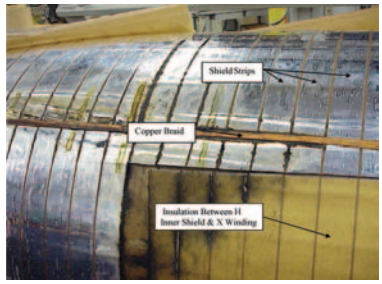

Figure 5: 115/46 kV, 42 MVA Teardown Center Leg, H Winding, Inner Shield

The source of the high OWA test values and the source of the acetylene were found at the location of the inner shield on the H winding of the center leg coil assembly. This is the location pointed to by the field OWA test. The teardown findings are shown in Figure 5.

The dark carbon areas under the copper bonding braid indicate that electrical contact was lost at many locations on the aluminum shield strips, which caused the strips to "float" electrically. This caused heavy partial discharge and arcing between the floating strips and the bonded strips and braid. The floating strips along with the carbon and burned insulation produced a significant enough change in the RLC circuit of the transformer, to be detected by the OWA test method in the field. The OWA FRA test was the only electrical test that detected the problem in the field.

Example 2: 3 x 448 MVA Single Phase Auto Bank, with Tertiary Winding (Fault Deformation)

The first set of sample results represents an OWA FRA test result comparing the tertiary windings on a set of 3 448 MVA, 500 kV (HV) to 230 kV (LV) auto transformers. The tertiary winding ratings are 13.8 kV, 97.5 MVA. The graphical results, as well as the phase to phase WND and OWA results are shown in Figure 6.

These results are shown to demonstrate the high degree of phase to phase similarity, and resulting low OWA that can be expected from a healthy three phase bank of transformers.

The second set of sample results in this example are from an OWA FRA test made on the tertiary windings on a similarly rated set of auto transformers, from the same manufacturer. Although the winding voltage and power ratings are identical on both sets, it is important to note that there is three years difference in the age of the units in the second set when compared to the first set, and the 60 Hz winding impedances are slightly different. An identical sister WND comparison is therefore not possible; however the phase to phase OWA FRA result is

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valid.

This example is interesting because one of the three transformers in the second set was subjected to two very severe successive low impedance tertiary winding faults during two separate energization attempts from the 500 kV network. The fault occurred as a result of a mistaken tertiary bus connection, with the unit being energized twice from the 500 kV winding within a short time frame. The graphical results, as well as the phase to phase WND and OWA results are shown in Figure 7.

The high OWA FRA test result on Y3Y1 (the tertiary winding on the transformer having been subjected to the fault) indicates that some permanent deformation has taken place within the winding. The owner of these transformers made the decision to reenergize the unit, without a visual inspection. At this time the transformer is back in service, with no failures reported to date. Follow up OWA FRA tests are planned when the transformers are next de-energized for periodic maintenance testing to monitor whether the tertiary asymmetry has worsened since the units were returned to service.

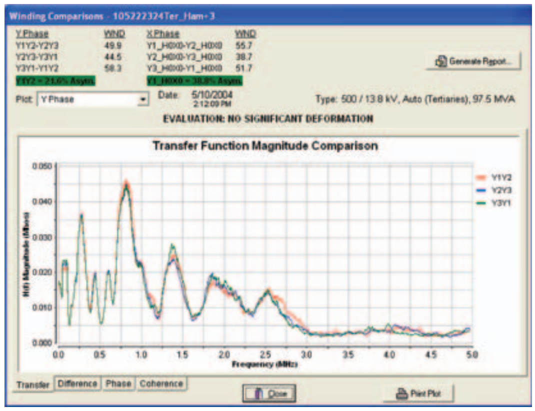

Figure 6: Field OWA FRA Test Results on 3 x 448 MVA Single Phase Auto Bank Tertiary Windings

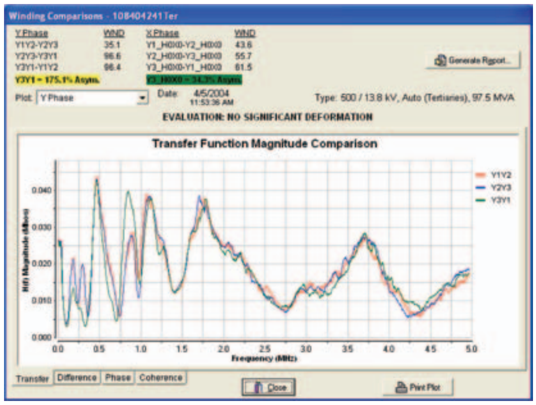

Figure 7: Field OWA FRA Test Results on 3 x 448 MVA Single Phase Auto Bank Tertiary Windings, Following Severe Phase to Phase Tertiary Fault

CONCLUSION

The power of frequency response analysis to look into large power transformers and detect mechanical damages is evident. The future of this technology looks positive, with significant new developments that hold the promise of greater sensitivity and repeatability than were previously thought possible. In addition, new evaluation techniques that make use of powerful computational software packages will lead to increased opportunities to provide objective comparison of results. Over time, these objective comparison techniques will replace the old subjective methods of comparison that rely heavily on expert analysis. New technologies that offer these improved techniques will set the course for the future of FRA as a viable testing tool.

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new generation that is under construction or approved, or the 9,000 or more megawatts that are in various stages of approval," she says. "And that is in addition to restarting Pickering and the two units at Bruce nuclear."

Insofar as new nuclear generation, Campbell points out that nuclear is "a major contributor" to generation in Ontario, and that any new construction of nuclear plants "would be a government decision."

EFFECT ON INDUSTRY

At the recent CAMPUT (Canadian Association of Members of Public Utility Tribunals) Conference in May, the last two decades of Ontario's generation and distribution policy were described as such:

- Relentless cost escalation under former Ontario Hydro regime sent Ontario from second-lowest price jurisdiction in Canada to second highest over 15 years;
- Provincial utility co-opting its shareholder and its regulator and was effectively out of control;

With this history, the breakup of Ontario Hydro and creation of an open market was seen as a welcome change; but there were concerns over:

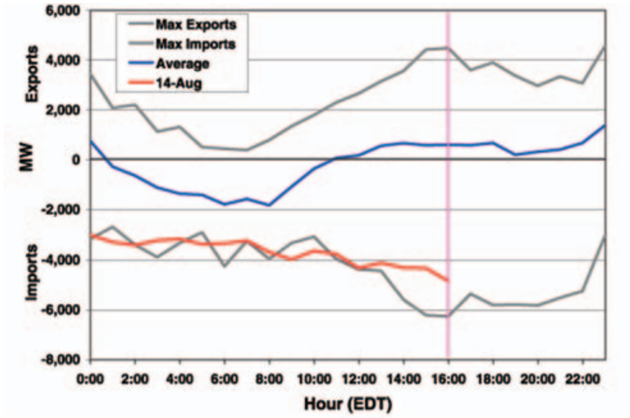
- opening the retail market and how it would unduly complicate the transition;
- the decision not to break up OPG into competing companies at the outset – seen as a compromise and ultimately a problem;
- and opening the market during a supply shortage – a timing issue.

Now, with Ontario buying power from other jurisdictions, the price is just too high for many industries.

Weyerhauser Corp.'s Dryden pulp mill operations have seen electricity costs increase 35 per cent since 2002; costs that make Ontario more costly to operate in than in any of its other North American operations. Vice President Norm Bush has gone on record stating that the Ontario branch of the company is having trouble justifying to head office why they should continue to operate.

Another paper mill, Bowater Inc., closed down for 18 days in Thunder Bay as that company seeks to cut its costs.

Ultimately, people like Mike Kuriychuk, chairman of the Association



of Major Power Consumers in Ontario, are hearing the cries of help from their members.

Although consumers won't see higher bills until next April (when the new rates come into effect) industrial users are already feeling the pain, seeing their electricity costs rising on average 30 per cent since 2000, as many buy their power in the spot market. Major employers (and electricity consumers) like steel giant Dofasco and nickel and zinc producer Falconbridge have seen costs skyrocket through the purchase of imported power.

Some Ontario communities are taking it upon themselves to guarantee a flow of power to their industry through supplemental sources of power.

HOLDCO, the parent company of the Town of Cobourg's utility company, has been actively seeking out power generation and cogeneration projects to meet the needs of local industry.

The President of HOLDCO, Bruce Craig, has acknowledged that the current high cost of electricity and ever present supply shortages make local generation and cogeneration a growing necessity.

MAINTAINING THE GRID

The 5 per cent province-wide voltage reductions on August 3 and 4 created brownouts at hospitals in Kingston and St. Catharines, where patients and staff were left without air conditioning in 40 degree Celsius temperatures.

Although the voltage reduction doesn't affect most consumers, hospitals are susceptible due to the sensitivity of their medical equipment.

Compared to its neighbours, Ontario has done a head in the sand act when it comes to meeting future electricity demand.

The New England states have constructed 24 natural gas-fired plants since 1999, creating more than 8,000 megawatts of generating capacity. Quebec, Manitoba, New York and Michigan are all in a position to sell Ontario surplus electricity, having both the capacity and the delivery infrastructure.

So far Ontario's response to meeting summer peak demand has been to buy more and more imported power.

Ontario Power Generation (OPG) restarted a 515-megawatt reactor that was under repair at its Pickering plant east of Toronto, but chose not to refurbish Units 2 and 3 (there are a total of 10 in operation). An 840-megawatt reactor at a nuclear plant on Lake Huron owned by Bruce Power LP was restarted in August. This coming on the heels of the April closing of the 1,140-megawatt Lakeview Generating Station near Toronto, as part of Premier Dalton McGuinty's election promise to eliminate coal-fired generation by 2007 (although the Premier did announce that the Nanticoke station - North America's biggest - would remain open until 2009 to ensure power demands are met). By 2009, all four of Ontario's coal-fired plants will be closed.

The province has 30,114 megawatts of generation capacity, with 36 percent of that total supply coming from nuclear. Hydro-electricity accounts for 26 percent, coal 21 percent and oil and gas contributing 17 percent.

More generating capacity is coming - 9,000 megawatts to be precise - but as Energy Minister Dwight Duncan has stated many times before, it is capacity that should have been coming online now, with the decisions made seven or eight years ago.

LOOKING TO RENEWABLE ENERGY

To ease demand, Queen's Park is encouraging "green producers" to set up renewable energy systems so they can sell so-called "clean" power to the grid at a fixed rate.

The program would be limited to smaller projects of less than 10 megawatts, in the hopes that thousands of megawatts of renewable generation will be created to offset Ontario's elimination of coal-powered plants by 2009 -

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which is 6,400 megawatts of capacity.

The plan - done in co-operation with the Ontario Power Authority and Ontario Energy Board - requires connection-policy changes to ensure non-discriminatory access to the grid. This would hinge on a feed-in tariff that would offer the right to interconnect with the grid for an average period of 20 years. The target is to have 5 per cent of total generation coming from renewable resources by 2007, and 10 per cent by 2010.

The plan makes Ontario one of the largest jurisdictions in North America to open its system to small suppliers of renewable energy paying a premium on each kilowatt of clean electricity purchased. Clean energy would include solar, wind, biomass and micro-hydro projects.

The policy is more far-reaching than California's clean energy efforts of the 1980s.

To date, Ontario has 10 projects planned that would provide 395 megawatts of "clean" power, with up to 1,200 megawatts announced for the province in July. The target is to generate 5 per cent of Ontario's energy capacity from renewable resources by 2007, rising to 10 per cent by 2010.

The entire North American electricity infrastructure represents more than $1 trillion (U.S.) in asset value, more than 200,000 miles — or 320,000 kilometers (km) of transmission lines operating at 230,000 volts and greater, 950,000 megawatts of generating capability, and nearly 3,500 utility organizations serving well over 100 million customers and 283 million people.

NERC's members are ten regional reliability Councils. In turn, the regional councils have broadened their membership to include all segments of the electric industry: investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal and provincial utilities; independent power producers; power marketers; and end-use customers. Collectively, the members of the NERC regions account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico. The ten regional councils jointly fund NERC and adapt NERC standards to meet the needs of their regions. The August 14 blackout affected three NERC regional reliability councils — East Central Area Reliability Coordination Agreement (ECAR), Mid-Atlantic Area Council (MAAC), and Northeast Power Coordinating Council (NPCC).

Five RTOs/ISOs are within the area directly affected by the August 14 blackout. They are:

Midwest Independent System Operator (MISO);

PJM Interconnection (PJM);

New York Independent System Operator (NYISO);

New England Independent System Operator (ISO-NE);

Ontario Independent Market Operator (IMO).

DEMAND ACROSS THE GRIDS FOR 2006:

• PJM Interconnection, which operates the power grid for all or parts of 13 states and the District of Columbia, announced on July 26 that it had successfully met a peak demand for about 135,000 megawatts (MW), a new record. PJM's previous record peak demand was 130,574 MW, reached on July 18.

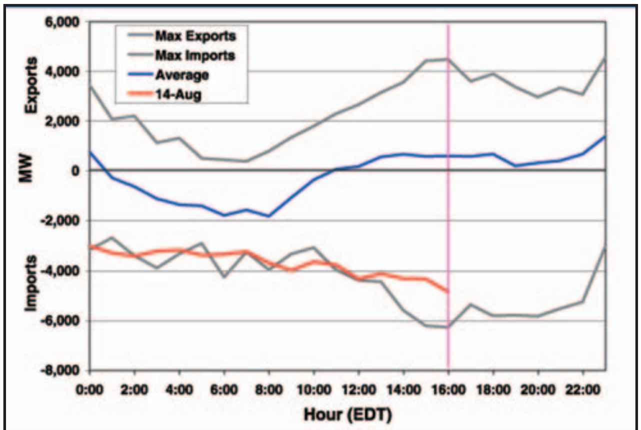
• On August 3, the Midwest Independent Transmission System Operator, Inc. (Midwest ISO), which manages the power grid for all or parts of 15 states and the Canadian province of Manitoba, successfully met a demand within its reliability footprint of 131,434 MW, topping the previous peak of 131,188 MW set on August 2.

• The New York Independent System Operator (NYISO) announced on July 26 that, for the second straight week, high heat and humidity drove statewide electricity usage to record levels. NYISO officials recorded a peak load of 32,075 MW on July 26, breaking the previous week's record of 31,741 MW.

• ISO New England, Inc., (ISO-NE) which operates the bulk power grid serving the New England region, announced it had reached an all-time high on July 27, topping out at 26,922 MW. The previous record, of 26,749 MW, had been set on July 19. Prior to 2005, New England's record was 25,348 MW, set in 2002.

• Southwest Power Pool, Inc. (SPP), which manages the power grid in all or part of seven southwestern states, has experienced high demand this summer as well. Non-coincidental peak for July 22 was 38,852 MW, surpassing the previous day's peak of 38,612 MW.

With the unusually high demand levels in the northeast, SPP has actually seen transmission patterns moving south to north, which is atypical for the summer months. All told, NYISO, SPP, ISO-NE, PJM and the Midwest ISO supply wholesale power to approximately 142 million people, roughly 48 percent of the U.S. population. ET



THE COST OF A BLACKOUT

On August 14, 2003, large portions of the Midwest and Northeast United States and Ontario, Canada, experienced an electric power blackout. The outage affected an area with an estimated 50 million people and 61,800 megawatts (MW) of electric load in the states of Ohio, Michigan, Pennsylvania, New York, Vermont, Massachusetts, Connecticut, New Jersey and Ontario. The blackout began a few minutes after 4 p.m. Eastern Daylight Time (16:00 EDT), and power was not restored for 4 days in some parts of the United States. Parts of Ontario suffered rolling blackouts for more than a week before full power was restored. Estimates of total costs in the United States range between $4 billion and $10 billion (U.S. dollars).1 In Canada, gross domestic product was down 0.7% in August, there was a net loss of 18.9 million work hours, and manufacturing shipments in Ontario were down $2.3 billion (Canadian dollars).

RICHARD SERGEL NEW NERC PRESIDENT

Richard P. Sergel is taking over the reins of the North American Electric Reliability Council (NERC).

Replacing Michehl R. Gent effective September 12, Mr. Sergel will be the new President and Chief Executive Officer following Mr. Gent's 24 years as leader of NERC.

Until 2004, Mr. Sergel served as President and Chief Executive Officer for National Grid USA, and was National Grid Group plc (public limited company) Executive Director for North America upon the completion of the National Grid and New England Electric System (NEES) merger in March 2000. From 1998 through the date of the merger, Mr. Sergel was President and CEO of NEES, where he held positions of increasing responsibility since 1979.

Mr. Sergel is presently a director of State Street Corporation and Massachusetts trustee of the Nature Conservancy. He also served on the boards of the Edison Electric Institute, the Consortium for Energy Efficiency, and the United Way of the Merrimac Valley. He holds a Bachelor of Science in mathematics from Florida State University, a Master of Science in applied mathematics from North Carolina State University, and a Master of Business Administration from the University of Miami.

"With the passage of reliability legislation in the United States, NERC has reached a watershed moment in its history. After an extensive search, the NERC Board of Trustees has determined that Rick Sergel is the right person to steer this organization through the many challenges that lie ahead," stated NERC Board of Trustees Chairman Richard Drouin. "We have the utmost confidence in Rick's ability to take the helm at this critical time for NERC," he added.

"We are truly pleased that Rick Sergel has agreed to lead NERC," says Mike Gent, NERC President and CEO. "His demonstrated talents as a visionary leader and effective chief executive officer will serve NERC well as it transitions to become the electric reliability organization authorized by the energy bill that President Bush signed into law (recently)."

Since its formation in 1968, NERC has operated successfully as a self-regulatory organization, relying on reciprocity, peer pressure, and the mutual self-interest of all those involved in the electric system. NERC membership comprises ten regional reliability councils whose members account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico.

OSHA Proposes New, Revised Electrical Safety Standards

The U.S. Occupational Health and Safety Administration recently proposed new and revised electrical safety rules that, because they would raise precedent-setting issues, should be of concern to every employer governed by OSHA standard. The proposal would:

• amend OSHA's existing Electric Power Generation, Transmission and Distribution Standard for General Industry 1910.269;

• replace the current Power Transmission and Distribution Standards for Construction with a revised set of standards similar to 1910.269;

• amend OSHA's electrical protective equipment standard.

Those wishing to comment on these proposed changes have until October 13 of this year.

Under the proposed rules, OSHA would inject itself into the area of multi-employer worksite liability by telling employers to, in effect, issue written notices of violations and corrective actions to each other - notices that would be requested by OSHA inspectors and would further assist OSHA in imposing liability under the multi-employer worksite doctrine.

For example, the rules would:

• require the host employer to report (apparently in writing) any observed contract-employer-related violations of the standards to the contract employer, and require the contract employer to advise the host employer (apparently in writing) of measures the contractor took to correct and prevent recurrences of violations reported by the host employer;

• require the contract employer to advise the host employer (apparently in writing) of any unanticipated hazards found during the contract employer's work that the host employer did not mention.

Auction for 1100 MWs of Capacity on Proposed New International HVDC Light Cable

Bidding on 1100 MW of transmission capacity and ancillary services available on two new proposed submarine cables across the Strait of Juan de Fuca began on September 14.

The international transmission lines that will be laid between Washington State and British Columbia would utilize HVDC Light cable and converter systems - leading-edge technologies characterized by low line losses, capability to provide high levels of voltage stability, and minimal impact on marine environments.

The routing for the cables calls for one line to run between Port Angeles on Washington State's Olympic Peninsula and Victoria on Vancouver Island, British Columbia, with a second line to run between Fairmount on Washington State's Olympic Peninsula and a terminus located in the Vancouver metropolitan area.

Permitting on the first line is well under way with application submissions expected before the end of the year. The target in-service date for the first cable would allow it to be on-line for the winter peak loads in 2007 with the second line to follow as soon as 2008. Both lines would provide for bi-direction power flow. When built these two cables are expected to significantly enhance inter-regional power flows and significantly augment the regional transmission systems.

The interconnecting utilities will be Bonneville Power Administration ("BPA") in Washington State, and British Columbia Transmission Corporation ("BCTC") in British Columbia. The project has been under development since October 2003, with the first interconnection filings made with BPA and BCTC in June 2004. An application for a Presidential Permit was filed in February 2005, and BPA's "Transmission Interconnection System Impact Study" was completed August 15, 2005.

Sea Breeze Power Corp. and Sea Breeze Pacific Juan de Fuca Cable, LP are the driving forces behind the project.

NEVADA'S ENERGY BILL GETS "CLEAN POWER" RIGHT

By Stephen Heins

Now that the dust has started to settle on Nevada's Assembly Bill 03 which was signed into law by Governor Kenny Guinn on June 17, 2005, I would like to review its most forward-looking provisions. This then is another article about "best practices" for utilities, energy legislation, state energy regulation and energy end-users in the electricity industry. So far, I have written about the State of Pennsylvania, the State of California, General Electric, the Wisconsin Public Service Commission, Alliant Energy and now Nevada.

First, let me say that the Nevada energy bill is much more targeted than the recently passed federal energy bill. While the national energy bill is laden with subsidies for controversial, dirty and costly energy options such as nuclear power and coal-fired power plants, the Nevada bill has almost no such subsidies. It can be read as a practical bill that addresses many state issues without succumbing to the pressures of self-serving industry lobbyists.

Nevada is currently the fastest growing state in the country in terms of population and energy consumption

By way of background, Nevada is currently the fastest growing state in the country in terms of population and energy consumption, with consumption increasing nearly 70% from 1990 to 2000. While growth in energy consumption has slowed through the energy crisis that has gripped all of the western states, not just California, in 2001, Nevada's economy has since rebounded.

Anyway, the cornerstone of the new Nevada Energy Bill is the emphasis on energy efficiency and Demand Side Management, but not your father's version of either. Nevada's Energy Bill addresses several key economic issues. First and foremost, the bill provides financial and technical assistance to the mining and manufacturing sectors. Using recent energy audits, a leading energy efficiency think tank, the Southwestern Energy Efficiency Project (SWEEP), determined that manufacturing could effectively save up to 35% of their electricity usage by 2020 and the mining industry could save anywhere from 18% to 37%.

In fact, the Western Governor's Association thinks energy efficiency is so important that it adopted a "clean energy resolution" in June of 2004, which includes a goal of increasing energy efficiency in the western region 20% by 2020. This is similar to the European Union's recent call for 20% of energy efficiency from all energy sources by 2020.

In order to dispel any hints of corporate welfare, the Nevada energy bill has a strict measurement and verification protocol; on the other hand, the bill addresses the four important business barriers to business participation: lack of awareness, difficulty of implementing energy projects, lack of operational priority and the limited capital available. In fact, SWEEP found that "all of these factors lead industries to typically implement energy efficiency projects that have a two-year payback or less, if such projects are implemented at all."

Another key component to Nevada's Energy Bill is that it addresses the chasm between landlord and tenant, which is especially problematic when it comes to commercial and industrial properties. In those settings, the landlord generally uses a "triple-net" lease for their property, which requires the tenant to pay all operational expenses for the property including electricity. Usually, this means that there is no incentive for landlords to make energy efficiency improvements to existing buildings, because the tenant gets the value of the energy savings. To overcome this problem, Nevada has established a partial exemption from real estate taxes for privately owned buildings that meet some provisions of the green building standards of the U.S. Green Building Council's Leadership in Energy and Environmental Design (LEED).

Then, there is the matter of combining energy efficiency and renewable energy into a "clean energy portfolio standard". Like Pennsylvania's "Advanced Energy Technology Portfolio", Nevada's new energy bill establishes clean energy standards that allow energy savings from cost-effective energy efficiency measures as well as energy supply from more costly but important renewable energy technologies to qualify. The overall standard was increased to 20% of total electricity supply in 2015, and the amount provided by energy efficiency measures is capped so that the emphasis remains on renewable energy technology implementation.

State governments, utilities and regulators are finally starting to treat energy efficiency as a supply side option, with an allowable return on investment. In the case of Nevada's investor-owned utilities, they can now justify to their shareowners their investments to reduce demand and make energy efficiency a growing part of their portfolio of energy options.

Unlike the Federal energy bill, the Nevada bill takes meaningful strides to advancing energy efficiency and renewable energy implementation. It will diversify Nevada's energy supply while providing economic and environmental benefits to the state's citizens and businesses.

With great examples of leadership from California, Pennsylvania, Wisconsin and Nevada, there is every reason to be optimistic that real energy solutions will bubble up through the states and finally transform U.S. energy policy.

Stephen Heins is VP of Corporate Communication, Orion Energy Services

HOW CANADA'S ENERGY MARKETPLACE IS TAKING SHAPE

Editor's note:
The following excerpts come from the 2005 PricewaterhouseCoopers' Canadian Energy Survey:

In this year's survey, PricewaterhouseCoopers continue their analysis of the Canadian electricity industry and focus on the emerging issues across the country that help shape and define Canada's energy marketplace.

BRITISH COLUMBIA

Since the creation of the new crown corporation, BC Hydro Transmission Corporation (BCHT) in 2003, BC Hydro has been involved in the ongoing discussions and development of the regional transmission organization (RTO) in the North West of the United States. Through BCHT, BC Hydro will incorporate the interests of the province in the ongoing negotiations on the development of RTO West.

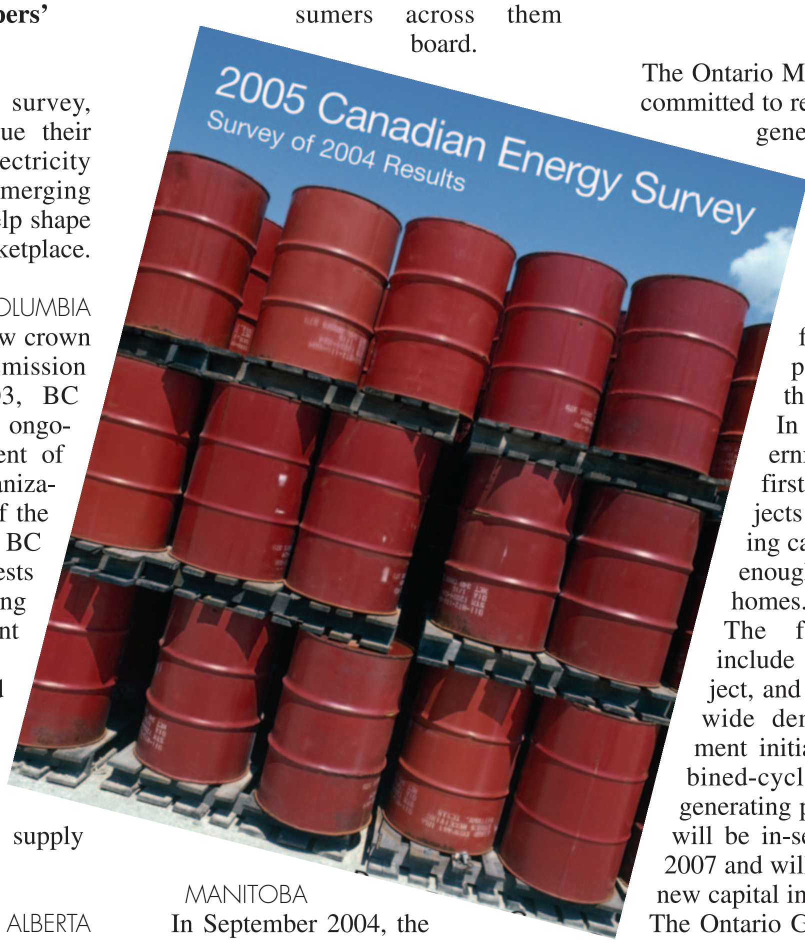
In 2004, BC Hydro updated its Integrated Electricity Plan (IEP) and presented its long-term plan for acquiring the required electricity resources to meet anticipated electricity supply needs.

ALBERTA

Alberta's restructured electricity industry has created a market environment that has stimulated new generation supply in recent years. For example, over 3,200 MW of new generation was added to Alberta's power supply since 1998 and an additional 5,000 MW of power has been announced for future development.

Alberta's electricity supply mix consists of almost 50% coal and more than 40% of gas. Alberta currently has approximately 200 MW of wind power, making it the province with the largest wind capacity.

With all of the new power projects under development, some analysts have estimated a current surplus of electricity in Alberta at nearly 40%. That level of supply should be good news for consumers across them board.



MANITOBA

In September 2004, the governments of Manitoba and Ontario agreed to jointly undertake a detailed technical study on the Clean Energy Transfer Initiative (CETI) that includes a proposed hydroelectric power project in Northern Manitoba and the development of a transmission line to bring the power from Manitoba to Ontario. This project will assist Ontario in meeting its electricity supply shortage (by 2014, Ontario will need 11,600 MW of new supply) and will also reduce greenhouse gas emissions.

Talks continue about the possibility of an east-west power grid, which would enable Manitoba to sell more of its excess power to Canadian provinces in addition to continue to sell its hydroelectric power to the United States.

ONTARIO

The Ontario Ministry of Energy has committed to replacing its coal-fired generation with cleaner sources of energy or demand-side measures. In early 2004, the government issued a request for proposal for 2,500 MW of power to help meet this commitment.

In April 2005, the government announced the first four winning projects with a total generating capacity of 1,675 MW, enough to power 650,000 homes.

The first four projects include a cogeneration project, and innovative province-wide demand side management initiatives and two combined-cycle natural gas-fired generating plants. These projects will be in-service by the end of 2007 and will bring $1.1 billion in new capital investment to Ontario.

The Ontario Government has mandated that smart meters be installed in all consumer households in Ontario in a two-phased program. Phase One aims to have 800,000 meters installed by December 31st, 2007 with the balance, Phase Two – approximately 3.4 million meters – installed by December 31st, 2010.

Recent mergers of distribution companies in Ontario worth noting in 2004 include the creation of PowerStream Inc. from the merger of Hydro Vaughan Distribution Inc., Markham hydro Distribution Inc, and Richmond Hill Hydro Inc. In addition, Hamilton Hydro

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and St. Catharines Hydro merged to form Horizon Utilities Corporation.

QUEBEC

Thanks in part to a return to major hydroelectric development projects and groundbreaking at two construction sites, Hydro-Québec is once again an economic driving force in the province. In fiscal 2004, Hydro-Québec posted net income of $2,435 million compared to $1,938 million in 2003.

Hydro-Québec Distribution (HQD), the distribution subsidiary of Hydro-Québec, has lowered its anticipated supply requirements in its 2005-2014 Electricity Supply Plan from the projections in its August 2003 forecast due in part to the higher volume of wind generated electricity (an increase of 0.7 TWh), an increase in energy savings of 1.5 TWh, and a 2.9 TWh decrease in demand from industry related to slower growth.

NEW BRUNSWICK

On April 1, 2004, the electricity market in New Brunswick was opened to competition for municipal utilities and large industrial customers.

In late September 2004, the province of New Brunswick took its first steps toward partial deregulation of the electricity market by splitting New Brunswick Power into five separate companies: NB Power Generation, which is responsible for generation of electricity at 15 facilities throughout the province; NB Power Nuclear, which operates the nuclear facility at Point Lepreau; NB Power Transmission, which operates and maintains 6,700 km of transmission assets in the province; and NB Power Distribution and Customer Service, which services over 363,000 residential, commercial, wholesale and industrial customers throughout the province.

NEWFOUNDLAND AND LABRADOR

At the end of 2004, the Governments of Newfoundland and Labrador and Newfoundland and Labrador Hydro (NLH) agreed to explore opportunities to further develop the Churchill River located in Labrador, in the Northeast region of Canada. The Churchill River has long been recognized as a significant, low cost supply of clean, renewable energy and the Lower Churchill River has yet to be fully developed. The primary sites along the Lower Churchill River include: Gull Island (2000 MW), and a smaller site at Muskrat Falls (824 MW).

REDUCING SF6 EMISSIONS FROM HIGH AND MEDIUM VOLTAGE ELECTRICAL EQUIPMENT

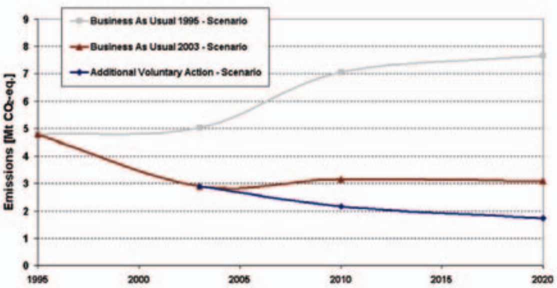
By Sina Wartmann and Jochen Harnisch, Ecofys

SUMMARY OF THE FINAL REPORT TO CAPIEL

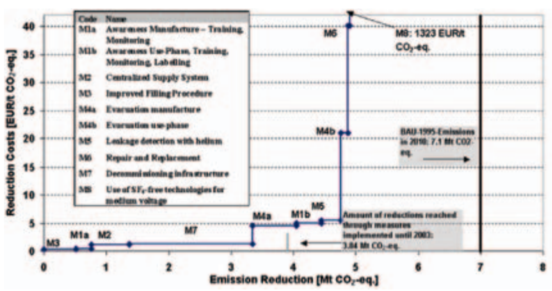
A study was conducted by Ecofys at the request of CAPIEL (in co-operation with EURELECTRIC) to provide a point of reference for discussions regarding the future framework for the handling of SF6 in electrical equipment in Europe. The report describes the key applications in which SF6 is used, and presents the latest estimates of SF6-amounts banked in equipment and emissions in the past (1995 and 2003) and their likely future development until 2020. In doing so, the analysis quantifies emission reductions achieved since 1995 as well as the reduction potentials still available in the future, and their respective costs.

Based on the latest industry survey, emissions of SF6 from electrical equipment in Europe have decreased from about 4.8 Mt CO2-eq. in 1995 to 2.9 Mt CO2-equ (See top figure) today. These reductions have been achieved by improved handling of SF6 throughout the lifecycle of SF6-equipment including manufacture, use and end-of-life, despite a significant increase of the bank of SF6 in electrical equipment

Emissions are projected to rise after 2003 without further action by manufacturers and users, due to strong bank growth. In the alternative emission projection, taking the 2003 situation as a starting point and assuming that all currently available and economically feasible containment measures are fully implemented until 2010, a further emission reduction of 0.5 Mt CO2-equ in 2010 and 1.5 Mt CO2-equ in 2020 could be achieved compared to 2003.



Emission Projection 1995-2020 for three scenarios



Cost Curve for Reduction Options in 2010

Voluntary agreements have been in place for several years in a number of European countries with the aim of reducing SF6 emissions. These voluntary agreements differ in scope and level of detail. In the 2001 ECCP-Report, the EU-wide associations of manufacturers and users, CAPIEL and EURELECTRIC laid down a number of action items for the manufacturing and use-phase of SF6-electrical equipment. The emission development between 1995 and 2003 indicates that these voluntary actions/agreements have been successfully implemented.

For this study, reduction potentials and costs for a range of measures were assessed. As a result a number of reduction measures through all life-cycle-phases were identified and reduction potential and costs for these measures were determined. As well as the life-cycle-measures the use of SF6-free technologies were considered. The potential and costs of the use of SF6-free technology in the medium-voltage area was quantified. For the high-voltage range functionally equivalent SF6-free options are at present not available, so this option was not further considered.

Regarding costs of the reduction options in 2010 (see next figure) and 2020, around 90% of the total reduction potential during the life-cycle is available at prices between 0.25 – 6 /t CO2-eq. with roughly equal distribution of cost-levels over the life-cycle phases. The abatement costs of all options, however, were found to range from 0.25 to 2000 . Life-cycle measures were found between 0.25 – and 32 /t CO2-eq. for both years, the SF6-free alternatives in the medium voltage range were found to exhibit very high specific reduction cost, i.e. above 1000 / t CO2-eq.

It is estimated that by 2003, 75% of the total technical reduction potential had been realized, and all assessed measures in the life-cycle – apart from a measure proposing the establishment of a decommissioning infrastructure – had already been at least partly implemented.

Against the “Business-as-usual”-scenario, with projected emissions of 7 and 7.8 Mt CO2-equ in 2010 and 2020 respectively, reduction options over the life-cycle of between 5 and 6 Mt CO2-eq. annually were identified. Here the largest potential is available

ICUEE TO FEATURE INVESTORS CONFERENCE FOR 2005

By Don Horne

The International Construction & Utility Equipment Exposition (ICUEE), the "Demo Expo", is the leading exposition for equipment demonstrations and education for the construction and utility industries. It's a totally interactive experience where you can operate and test the equipment yourself in job-like conditions on a million-square-foot-plus outdoor area.

At ICUEE, attendees can experience first-hand equipment in action, working at ground level, underground and overhead.

Persons involved in all segments of the electric, sewer/water, phone/cable, gas, general construction, government and landscaping industries will be part of the more than 15,000 people expected to attend this September 27-29 in Louisville, Kentucky. Those attending will have a chance to meet with more than 800 suppliers covering 1.125 million net square feet of exhibit space. It's the best opportunity to compare the latest equipment, technologies and services to make informed purchasing decisions.

Want to know what's new in the industry? Then stop by ICUEE's New Product Area. This exciting new area will showcase the newest products and innovations from exhibiting companies. It's the place to find the latest technologies and advancements for the industry.

Also, the expanded education program features more than 40 education sessions with leading industry experts and case studies. Sessions include the latest safety, regulation, operational and technological issues affecting the utility and construction industries today.

For the first time at ICUEE an Investors Conference will be featured, spotlighting the utility construction equipment marketplace to a select group of financial analysts. Organizing the event is the show's owner/producer, the Association of Equipment Manufacturers (AEM), with Morgan Stanley co-sponsoring.

The AEM Investors Conference will be held the morning of September 28 and include individual company presentations and a pre-show exhibits tour. The event is modeled after the investor conferences AEM conducts at the gigantic CONEXPO-CON/AGG international construction-related exposition.

The Underground Construction Technology (UCT) program will co-locate a special UCT Educational Program to provide attendees with high quality educational programming in underground construction. UCT will conduct up to 18 sem-

Continued on Page 41

ICUEE

From page 39

inar sessions and the seminar programs will include sessions targeting above-ground and overhead equipment technologies and trends.

The last biennial ICUEE, held in 2003, had more than 790 exhibitors in 1.1 million net square feet of exhibit space - the second largest tradeshow of any kind in the United States that year. The field demonstration concept was developed in 1964 as a means of solving an equipment evaluation and communications problem. Illinois Bell invited 12 trencher manufacturers to demonstrate equipment on the same day in the same field. In the summer of 1966, the show was recreated on a more formal basis and continued to grow in 1969 and 1972.

Manufacturers of many kinds of equipment from across the country were invited to turn the farmland near Elburn, Illinois into a productive three-day utility equipment show. The event moved to the DuPage County Fairgrounds for the 1975 and 1977 shows. Eventually the show grew to such a level that Illinois Bell could no longer manage it, turning it over to a professional management firm in 1978. The show moved to Kansas City in 1979, then to Louisville, Kentucky starting in 1987. AEM had provided industry direction and in the late 1980s became show owner and producer. ET

CON EDISON UNVEILS $10.6 MILLION SAFETY PLAN FOLLOWING ACCIDENTAL DEATH

The tragic electrocution of a New York City woman has led Con Edison to agree to spend $10.6 million on stray-voltage detectors and other safety initiatives.

Con Ed will use company vans with mobile stray-voltage detectors to travel at slow speeds looking for potentially dangerous sites.

If a problem is detected, company personnel would correct it or secure the area if another utility is involved, the PSC said.

Con Ed will also undertake annual surveys of its underground system plus additional surveys within five days of storms that result in the salting of city roadways.

Jodie Lane was electrocuted on January 16, 2004, when she stepped on the metal cover of a utility box while walking through the East Village with her two dogs. Following an investigation, Con Ed concluded workers had failed to wrap properly an exposed wire in an electrical box.

The Lane family also received a cash settlement from the utility.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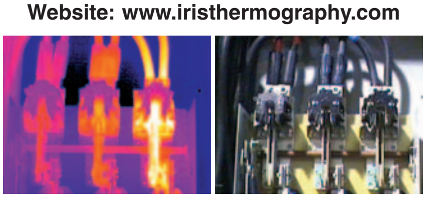

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CALIFORNIA UTILITIES INSTALL BREAKTHROUGH HIGH-CAPACITY CONDUCTOR

A breakthrough high-temperature, low-sag overhead conductor designed to help eliminate transmission bottlenecks that increasingly have plagued electricity grids in recent years, causing brownouts and blackouts, is getting its first use in California.

Pacific Gas & Electric (PG&E) and a second utility, in Southern California, have installed Aluminum Conductor Composite Reinforced (ACCR) on short line segments near substations in Santa Clara and Oceanside (just north of San Diego), respectively. The Oceanside installation was funded in part by the California Energy Commission. The Electric Power Research Institute (EPRI) will monitor the line's performance. PG&E funded its own installation and is performing its own monitoring.

Three other major U.S. utilities have installed, or announced plans to install, the new conductor on transmission lines in the West, Midwest and South.

"Parts of California have experienced record demand for electricity this summer, which puts stress on the power grid," says Tracy Anderson, business development manager for 3M's composite conductor program. "The ACCR provides a quick and reliable solution to increase the capacity of existing transmission lines by as much as 100 percent without requiring new towers or new rights-of-way,"

Anderson notes that Xcel Energy, a major utility, is already using the ACCR to relieve congestion on a 10-mile line in the Minneapolis-St. Paul region. In addition, the Western Area Power Administration recently said it will install the ACCR on a key 80-mile line in Arizona, and Alabama Power Company plans to install the new conductor on a critical 10-mile line in the eastern part of the state.

The ACCR is a new type of metal overhead line that contains a multi-strand core of heat resistant aluminum matrix composite wires. The conductor retains its strength at high temperatures and is not adversely affected by environmental conditions. Its light weight and reduced thermal expansion properties are what enable installation on existing towers, with no requirement for visual changes to a line or additional rights of way.

Prior to being commercialized, the ACCR underwent four years of rugged, extensive field testing by several utilities, partially funded by the Department of Energy, and met all expectations.

The first two purchases of the ACCR were made by utilities that participated in field testing, for installation in areas subject to extreme weather conditions.