North American Policies and Technologies
Electricity Transmission & Distribution Today
THE ELECTRICITY FORUM

April 2008
Volume 20, No. 3

Integrating Monitoring and Diagnostic Equipment on Aging Transformers

Valuable information on maintaining critical infrastructure

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PUBLICATION MAIL AGREEMENT # 40051146

ELECTRICITY TODAY

Volume 20, No. 3 April 2008

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Distribution: free of charge to North American electrical industry personnel who fall within our BPA request circulation parameters. Paid subscriptions are available to all others.
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215-1885 Clements Road,
Pickering, Ontario, L1W 3V4
or on-line at www.electricityforum.com.

Canada Post - Canadian Publications Mail Product Sales Agreement 40051146
ISSN 0843-7343
Printed in Canada.

Member of:
CCAB BPA WORLDWIDE BUSINESS

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AREVA'S ARGUMENT FOR A MADE-IN-CANADA REACTOR

By Don Horne

The largest concentration of Canadian Candu reactors is in Ontario, and the strongest argument by Candu and Atomic Energy of Canada Ltd. (AECL) for new reactor construction is to go with home-grown technology conceived and built by the people who will be using the power generated by these new reactors.

Competition to win contracts for the new reactors scheduled to be built across the United States is stiff, with Westinghouse (Toshiba), NuStart Energy (General Electric), and Mitsubishi all jockeying to play a lead role.

Another country with a strong nuclear past – France – is home to AREVA, and that company is making itself quite at home in North America and hopes to cash in on this building boom. AREVA has formed UniStar Nuclear with Constellation Energy in the U.S. to take advantage of the American market.

As well, AREVA wants to be contributors to the energy future of Ontario and of Canada as a whole.

Armand Laferrère, President and CEO of AREVA Canada Inc., feels that AREVA can trump the homegrown argument made by AECL when it comes to including 'Canadian content'.

"A Canadian EPR (Evolutionary Power Reactor) would include as much Canadian content as we possibly can," says Mr. Laferrère. "To give you an example, we qualified 300 subcontractors on the Finnish project – and Finland did not have anything like Ontario's first-rate nuclear industry to begin with. Canadian content for Canadian builds is not the whole story, however. As a supply chain builds up and is strengthened, it can make more and more sense to have some specific equipment built by one subcontractor for all or part of the global market.

"Canada, just like other jurisdictions, could therefore gain increased revenues from becoming a site for EPR components worldwide, or at least for all of North America."

All that AREVA needs to make their reactor work in Canada are subcontractors, engineers and partners – which Canada has in abundance.

"Canada's nuclear industry has a comparable safety record, and has been a great success story too," says Mr. Laferrère. "This is a good thing for AREVA: on the whole, we have a preference for entering into alliances with winners. At a time of growing risks, we would like to offer you an opportunity to diversify, expand and build on past successes to prepare for tomorrow's challenges. We believe that this would help the Canadian industry to remain at the cutting edge of nuclear technologies, and it would certainly provide new opportunities for Canadian engineers and Canadian subcontractors."

Ontario's ruling Liberals have recently told AECL they won't purchase new reactors from them unless the federal government will be the ultimate backer of the Crown corporation. This comes on the heels of rumours that Ottawa is ready to privatize AECL and wash its hands of the nuclear business.

Music to the ears of AREVA Canada.

"Partnering with the Canadian Nuclear Industry definitely would be in the interest of AREVA," says Mr. Laferrère. "I think it would be typically the good example of a win-win situation because nuclear demand the world over is shooting (through the roof) – AREVA needs more skills, AREVA needs more contractors, more engineers."

The argument is a simple one – and one that plays very much into AREVA's favour: 'demand is high for our product, so any local expertise and help you can provide, we will take.'

"If some of the talent that exists in Canada can be used from Canada in that technology it is good for us - and, at the same time, for the Canadian nuclear industry by diversifying its skills, getting to know not only the domestic home-grown heavy-water technology but also the light-water technology which is most of the world demand right now. I think it is good for this industry to be able to work in both."

AREVA's reactors are of the light-water type, as opposed to the AECL Candu models that use heavy-water technology. Mr. Laferrère sees an investment by Canada in light-water technology as an investment in that country's future as a nuclear energy superpower.

"In my view, this great country needs to leverage its existing strengths and to make nuclear a bigger part of its legitimate ambitions to become an energy superpower. This means that Canada should not only develop skills in its home-grown technology, which accounts for 10% of the existing global fleet, but also gain a significant foothold in the light-water technology, which today represents clearly more than 90 per cent of world demand."

Mr. Laferrère told a Toronto business audience recently that the company would rely on as much Canadian content as possible and that in time it might make sense that some specific equipment be built solely in Canada and shipped worldwide. An internal AREVA study suggested that 70 per cent of an AREVA reactor could be built in Canada.

Although his is an objective opinion, Mr. Laferrère doubts that Ontario industry will benefit from international demand if it remains wedded to one technology alone.

It is hard to disagree with him. Light water technology can complement and co-exist with heavy water technology.

The winner-take-all philosophy for selecting new reactors should be shelved in favour of a more tempered approach – allowing both AREVA and AECL to build the new reactors slated for the Canadian market.

Perhaps a little competition will ensure that these new reactors arrive on time and on budget. And if one of them fails to do so, it will make it much easier to choose a primary supplier for the future. *don@electricityforum.com*

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POWER TO THE PEOPLE - SAFELY

By Diana Ward

UV Cable Covers are used as a protective sleeve between overhead lines and transformers. It has been specifically designed to reduce power outages caused by wildlife and deadfall of tree foliage across live lines, reducing bush fires.

Electrical safety mats, covers and drapes prevent electrical currents flowing from power lines to people. Without this safety equipment, electrical workers would be at risk in their daily work. As an Australian top 100 company, electricity supplier Energex Limited adheres to the philosophy that employee safety is paramount.

"Other electrical safety authorities follow in Energex's footsteps because it is proactive in employee safety and others adopt its philosophy," says Victor Gandolfo, Sales and Marketing Manager, Trelleborg Engineered Systems Australia.

To supply electricity to 1.2 million residential, industrial and commercial customers in South East Queensland, Australia, Energex maintains bulk supply and distribution substations, transformers, power lines and cables. This means that its employees must work with live electricity at both low and high voltages. Without appropriate safety equipment, such as safety mats, electrical workers would risk electrocution when performing their everyday duties.

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Safety first

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"Trelleborg has developed custom-made electrical safety mats, covers and drapes that cover live electrical boards or overhead lines to protect the user from electrocution while working between lines or to insulate from the ground as a protective barrier," says Gandolfo.

"The most important criterion is the mat's ability to prevent electrical currents flowing from live lines to people."

Products must pass the applicable standards. In Energex's case, this includes registered standards in Australia/New Zealand for low-voltage mats or the American Society for Testing and Materials (ASTM) International standards for high-voltage products.

LV Line Covers are also known as double-drop mats and are hung over overhead power lines to provide a safety barrier while workmen conduct maintenance or repairs on overhead wires.

LV Safety Matting is mainly used for standing on while working on live switchboards or any other equipment and prevents the possibility of electrocution.

"Energex required a high-voltage orange mat manufactured to match an existing mat for high-voltage overhead power line work," says Gandolfo. As part of the customized solution, Trelleborg not only considers dimensions, thickness and cut, but also the rubber compound that forms the basis of the mat.

Queensland's tropical climate and year-round harsh sunlight rapidly takes its toll on rubber. The right rubber compound is one of the key solutions that Trelleborg must deliver.

"All electrical safety products are primarily made from a natural rubber blend. We develop compounds that will give the mat the desired flexibility and electrical performance," says Gandolfo.

"In Queensland the amount of sunlight was the big issue. This means that the mats tend to have a shorter life because sun is very harsh on rubber material – it makes it crack," he says. "To combat this, we are working with alternative rubber compounds focusing on this problem and strengthening patches on fold sections or high-impact areas on mats."

Trelleborg's mats were put to the test in the aftermath of Cyclone Larry in Northern Queensland in March 2006. The severe tropical cyclone disrupted electricity transmission, hampering relief and cleanup efforts. To aid in the speedy reconnection of electricity to the area, Energex crews, usually servicing South East Queensland, were sent to assist local crews.

"Trelleborg's safety mats were so well received that local crews also wanted them," says Gandolfo. "The most important aspect is that the mats we provide work and save lives, offering people a safe working environment."

SAFETY BASED ON LOCAL STANDARDS

Trelleborg Engineered Systems Australia's largest customers are active in the power generation and distribution industries, but its products are also used in the telecommunication industry. More recently, the customer base has expanded to include an increasing number of second-tier service contractors, such as domestic electricians.

Its most popular product is the Low Voltage (LV) Safety Mat. Trelleborg provides custom-made solutions for customers according to individual parameters. It is the only Australian manufacturer of electrical safety matting products complying with Australian and international standards, including full testing and product certification, and its market share is approximately 30 percent.

HIGH RESISTANCE GROUNDING - AVOIDING MISAPPLICATION OF TVSS AND UPS SYSTEMS

By David Murray, P.Eng., Schneider Electric; Robert Hanna, P.Eng., RPM Engineering Ltd.; and John Dickin, P.Eng., Dickin Engineering Inc.

High resistance grounding of 600 V power distribution systems is applied in hospitals, data centres and telecom facilities where supply availability is demanded. High resistance grounding provides service continuity during a ground fault. It also enhances electrical safety by preventing a ground fault from escalating into an arc flash incident.

However, care must be taken during electrical system design to ensure that transient voltage surge suppressor (TVSS) and uninterruptible power supply (UPS) systems are properly applied. Installation of a TVSS or UPS designed for a solidly grounded system into a high resistance grounded (HRG) system can lead to unintended failures that reduce service continuity. During ground fault, transient voltage surge suppressors can rupture; UPS systems can fail with subsequent loss of critical load; and the critical load can be exposed to risk if incompatible grounding exists between the UPS bypass and output.

CONCEPT OF HIGH RESISTANCE GROUNDING

Figure 1 shows a 600 V high resistance grounded system. A resistor is inserted between neutral and ground to limit ground fault current to 5 A or less. The 2006 Canadian Electrical Code addresses HRG in rules 10-1100 thru 10-1108.

The majority (approximately 80%) of electrical faults are of ground type. By maintaining service continuity during ground fault, HRG improves system availability for the majority of electrical faults as compared to a solidly grounded system. A ground fault can be safely traced while the circuit remains energized.

Fault isolation and repair can then be temporarily deferred to a time more convenient for facility operations.

A low-level arcing ground fault on a solidly grounded system can escalate into an arc flash incident. By limiting ground fault current, high resistance grounding prevents single ground faults from escalating into arc flashes, thereby improving electrical safety.

During a bolted ground fault on a 600 V system, the neutral voltage rises to 347 V above ground and the two unfaulted phases rise by a factor of 3 to 600 V above ground, as shown in Fig. 2.

TVSS and UPS for use on a HRG system must be designed to accommodate this voltage rise during ground fault.

TRANSIENT VOLTAGE SURGE SUPPRESSORS

A TVSS consists of metal oxide varistors (MOV) that exhibit high impedance when system voltages are normal and low impedance when transient voltages are applied. The low impedance diverts surge current away from the load and back to the source to protect the load against transient voltages. An MOV has a maximum continuous overvoltage (MCOV) rating.

In a solidly grounded 347/600 V system, MOVs connected line-to-ground must be able to withstand 347 V plus a margin of 20% continuously. Hence they require an MCOV rating of 420 V.

There have been instances where TVSS have ruptured in 600 V high resistance grounded distribution systems. Typically, a 600 V distribution system will be high resistance grounded through a 5 A, 347 V, 69   neutral grounding resistor.

Investigation of one such incident at

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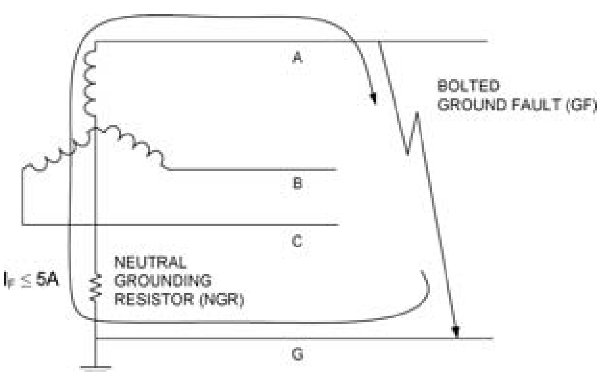

Fig. 1 High Resistance Grounding of a 600 V System

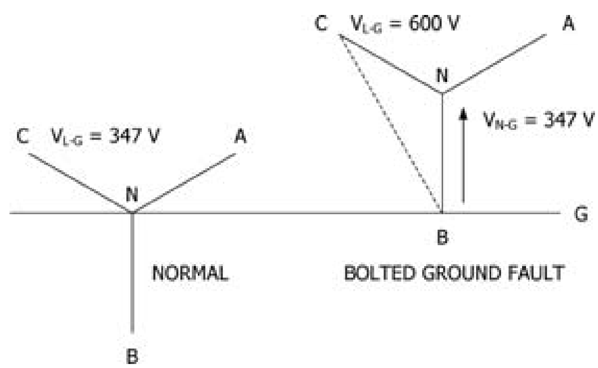

Fig. 2 Voltage Rise During Ground Fault on a HRG System

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a data centre in Ontario revealed that the TVSS failed during a ground fault when the metal oxide varistors (MOVs) connected between line-to-ground (L-G) were exposed to excessive voltage. The TVSS was rated for use on a 3-phase, 4-wire, 347/600 V solidly grounded wye system. It had been misapplied to the HRG system.

Figure 3 shows the typical connections and Table 3 shows the typical ratings of MOVs in TVSS units designed for a 600 V, 3-phase, 4-wire, solidly grounded system. L-L mode MOVs are shown dotted because they are often omitted. (Between any two phases are two L-N MOVs in series and two L-G MOVs in series, each pair providing line-to-line protection).

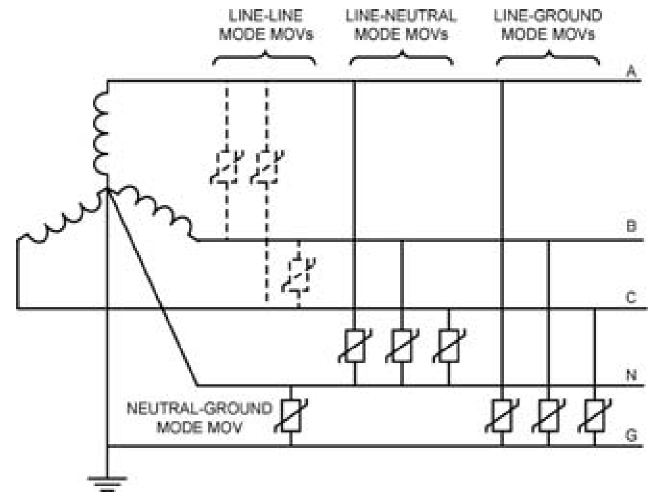

Fig. 3 TVSS for Solidly Grounded System

TYPICAL MCOV RATINGS FOR A 347/600 V, 3-PH, 4-W SYSTEM

Mode	L-N	L-G	L-L	N-G
MCOV	420 V	420 V	840 V	420 V

Table 3

An MCOV of 420 V is sufficient for MOVs connected L-G on a solidly grounded 347/600 V system. Continuous L-G voltage does not exceed 347 V ± 10%. On a HRG system, however, L-G voltage rises to 600 V (i.e., to rated line voltage) during a bolted ground fault. At this voltage, an MOV with an MCOV of 420 V will be stressed and eventually fail. That is why the MCOV of an MOV connected in L-G mode on a HRG system must be rated higher than the system line voltage. Figure 4 shows the typical connections and Table 4 shows the typical ratings of MOVs in TVSS units designed for a 600 V, 3-phase, 3-wire, HRG system.

600 V HRG systems are 3-wire. The neutral is not distributed because it becomes energized during ground fault. Hence, there is no need for L-N or N-G protection modes on a TVSS used on a 600 V HRG system.

HRG systems do not exhibit the 600% overvoltage phenomenon above ground that can occur in ungrounded systems during intermittent arcing ground faults. The let-through current of a neutral grounding resistor (NGR) is always chosen to

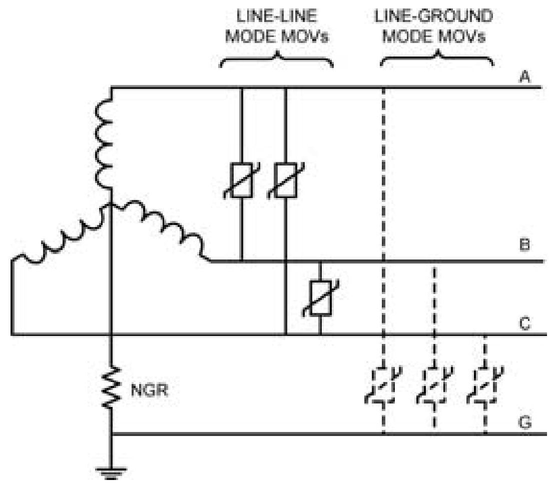

Fig. 4 TVSS for High Resistance Grounded System

TYPICAL MCOV RATINGS FOR A 600 V 3-PH, 3-W HRG SYSTEMS

Mode	L-G	L-L
MCOV	750	750

Table 4

be higher than the capacitive system charging current. This ensures that the continuous L-G voltage during a ground fault will not exceed 600 V on a 600 V system.

The 2006 CEC advises in Rule 133.2.1 that electrical equipment shall be suitable with respect to the maximum steady voltage (r.m.s. value for a.c.) likely to be applied, as well as overvoltages likely to occur. TVSS MOVs are not exempt.

The US 2005 National Electrical Code (NEC) requires in section 285.3(3) that the MCOV of a TVSS exceed the maximum continuous phase-to-ground voltage available at the point of application. Section 285.3(2) specifies that a TVSS used on a resistance grounded system be listed for use on this type of system.

It is anticipated that UL 1449, Transient Voltage Surge Suppressors, will be amended to add a listing for use on resistance grounded systems. When published, it is expected that the UL listing will remove some of the ambiguity in applying a TVSS to a HRG system. Until such a listing is available by UL, one must use what is known as a "delta-rated" TVSS, which is suitable for use on a HRG system.

MOVs in a delta-rated TVSS are typically connected in L-L and L-G mode, as shown in Fig. 4. L-G mode is shown dotted because some TVSS manufacturers offer delta-rated units with L-L mode MOVs only. Typical MCOV ratings are shown in Table 4.

It is not recommended that TVSSs be installed in ungrounded distribution systems due to the possibility of excessive phase-to-ground voltages that can occur during intermittent arcing ground faults.

UNINTERRUPTIBLE POWER SUPPLIES

3-phase 600 V UPS systems designed for use on solidly grounded power systems often employ MOV surge suppressors

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Resistance Grounding
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to protect the rectifier power electronic devices.

The phase-to-ground MCOV is typically insufficient for application on a HRG source. A typical UPS will include either a rectifier input autotransformer, or possibly no transformer at all.

Connecting this type of UPS to a HRG source can result in failure of the rectifier MOVs and loss of power to the critical load.

When purchasing a 3-phase UPS System, inform the UPS manufacturer whenever the UPS is to be fed from a HRG power source. The manufacturer will provide the UPS with a rectifier input isolation transformer to prevent the rectifier MOVs from being exposed to high phase-to-ground voltages during a ground fault on the upstream power source. Due to the possible presence of excessive phase-to-ground voltages on ungrounded systems, consideration should be given to converting ungrounded systems to HRG before installing a UPS.

Failure of Isolated Redundant UPS with a HRG System

A site in Ontario experienced a loss of power to the critical load on a UPS system that was connected to a HRG system.

The critical load was protected using dual 150 kVA rated UPS modules, connected in an isolated redundant configuration, as illustrated in Fig. 5. In this configuration the primary UPS is normally in service, while the secondary UPS is on “hot standby”. Upon loss of the primary unit, the critical load is automatically transferred to the secondary module via the static bypass switch in less than 1/4 cycle.

Each UPS was factory supplied with an input autotransformer and MOVs that were connected on the 600 V side to provide transient voltage surge protection. The upstream power transformer supplying power to the UPS system was rated 750 kVA, 27.6 kV/600 V, delta-wye. The transformer secondary neutral was grounded via a 5 A, 69 ohm, 347 V HRG system to provide supply continuity during a single line-to-ground fault.

The UPS system suffered a serious failure resulting in a total loss of power to the critical load. The primary module, its internal static bypass and the secondary module all failed.

Follow up investigation revealed that the factory installed MOVs were inadequate for application on the HRG system. The MOVs had a maximum MCOV of 420 V. Under normal operating conditions, the applied voltage to all MOVs is 347 V (line-to-ground), well within the MCOV. Under a phase-to-ground fault condition, the voltage of the faulted phase went to zero, while the voltage of other two phases increased to 600 V, thus overly stressing the MOVs. In this case, MOV3 connected to the primary module exploded, producing plasma material that shorted MOV4 on the static bypass. This occurred because the printed circuit boards for MOV3 and MOV4 were physically located just three inches apart, with no adequate barrier separating them.

To solve this problem, four delta-wye input isolation transformers, T1 thru T4, were installed as shown in Fig 5. The secondary neutral of each transformer was solidly grounded to ensure that the applied voltage across each MOV would not rise during a ground fault on the primary side 600V HRG system. The internal UPS inverter output transformers had always been solidly grounded. With the addition of transformers T1 thru T4, the UPS rectifier and bypass input sources became solidly grounded also. Additionally, a mechanical barrier was added between the circuit boards holding MOV3 and MOV4 as well as those of MOV1 and MOV2.

Compatible Grounding Between UPS Input and Output

Large UPS systems usually feature separate bypass and rectifier input power sources for added redundancy. A small data centre in Ontario had such a UPS, rated 300 kVA, 600V, 3-phase. Both the rectifier and bypass input power sources were HRG. The UPS was factory supplied with an internal rectifier input isolation transformer. At site, the UPS inverter output isolation transformer was solidly grounded. The UPS vendor was not informed that the building was high resistance grounded.

The first indication of a problem was the persistent appearance of a “Bypass Unavailable Alarm”. Investigation revealed a ground fault in the building HVAC system that was fed from the same power transformer as the UPS bypass input.

The ground fault shifted the bypass neutral voltage above ground by 347 V, whereas the solidly grounded the inverter output neutral remained at ground potential. The neutral voltage difference between the bypass and output created the “Bypass Unavailable Alarm”. The alarm cleared once the ground fault was located and repaired.

Further investigation revealed another grounding scheme issue. If a ground fault were to occur on the solidly grounded critical load, the UPS as designed would instantly transfer the load to bypass via the static bypass switch. The critical load would then remain parked on the HRG bypass. The neutral voltage

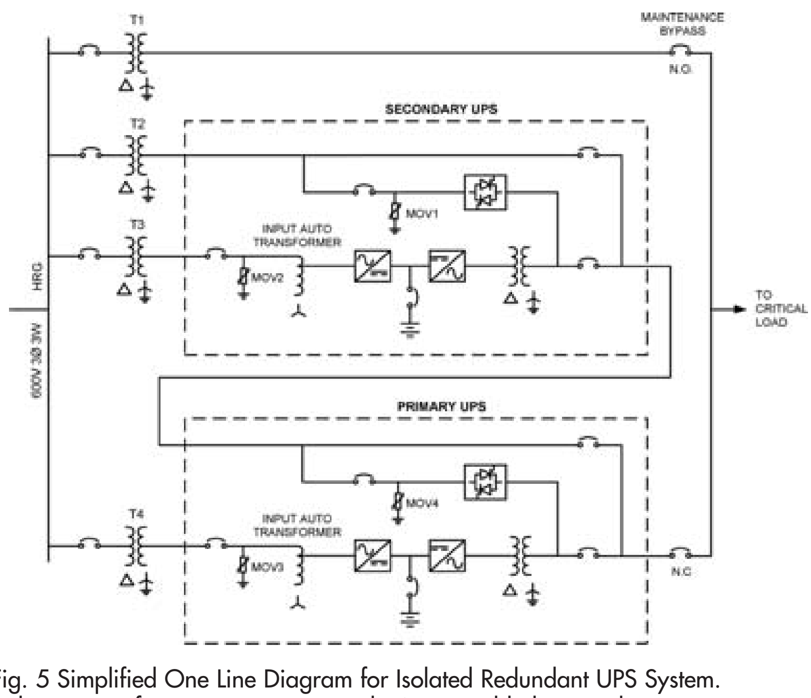


Fig. 5 Simplified One Line Diagram for Isolated Redundant UPS System. Isolation Transformers T1, T2, T3, and T4 were added on-site later to address the problem of UPS failure.

difference between bypass and solidly grounded inverter would prevent re-transfer, posing an unacceptable risk of downtime.

It is recommended that the bypass and inverter output sources be grounded the same way, either solidly grounded or HRG. Typically, if the building 600 V distribution system is HRG, then the 600 V UPS inverter output should also be HRG.

This way, a ground fault in the critical load would produce an alarm and not transfer to bypass. The faulted component in the critical load will not experience an unscheduled shutdown as would occur in a solidly grounded system.

If the critical load must be solidly grounded, then the UPS input and bypass sources should be isolated from the upstream HRG system and solidly grounded via delta-wye isolation transformers.

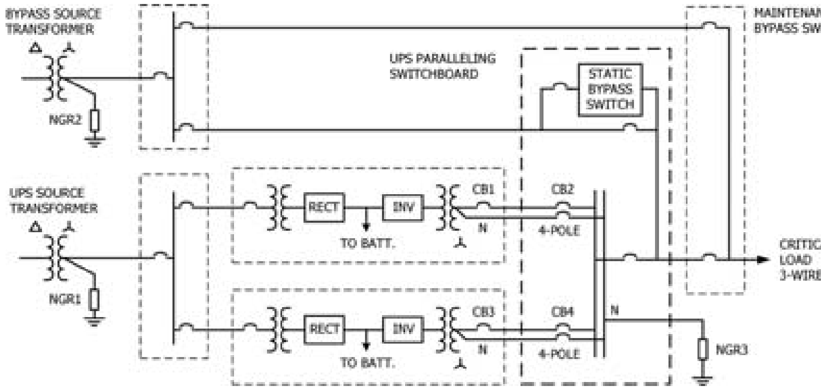


Fig. 7 High Resistance Grounding of a Parallel UPS System

Fig. 6 shows how to properly configure a UPS for an HRG system. NGRs are added at the UPS rectifier input, bypass input and inverter output (NGR1, NGR2 and NGR3). The UPS vendor can accommodate high resistance grounding when advised up front.

Ground alarm relays are required for each NGR to provide alarm indication upon ground fault.

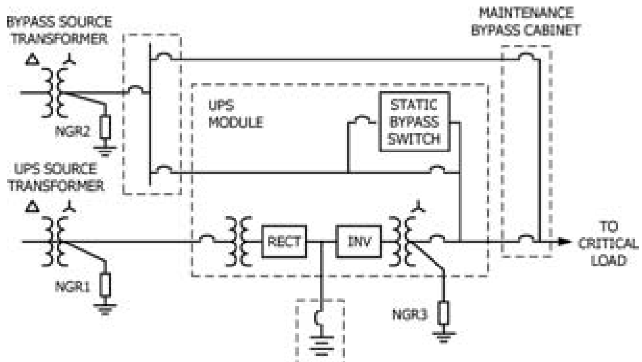


Fig. 6 Grounding of UPS Bypass Input and Inverter Output

High Resistance Grounding of Parallel UPS Systems

Parallel UPS modules increase the redundancy and capacity of a UPS system. Parallel UPS systems have traditionally been solidly grounded. They must share a common output neutral bus to facilitate single-point grounding, Significant circulating currents flow in the shared neutral; hence UPS manufacturers recommend a full capacity neutral cable.

A recent trend has been to use HRG UPS systems to increase critical bus availability upon ground fault.

For an HRG system, UPS vendors adapt the traditional solid grounding scheme by connecting a neutral grounding resistor (rated 2-5 A) between the output neutral bus and ground, shown as NGR3 in Fig. 7. The neutral bus becomes energized during a ground fault. When isolating a module for maintenance, the neutral must be disconnected along with the phase conductors. Neutral switching is typically done with 4-pole module output isolation breakers, CB2 and CB4 in Fig. 7. A UPS service technician must remember that opening the UPS internal 3-pole breakers CB1 or CB3 alone will not isolate the UPS module from the bus.

It is suggested that UPS manufacturers consider using the grounding scheme widely used on parallel HRG generators, proposed in Fig. 8. This scheme uses an artificial neutral zigzag grounding transformer to access the system neutral for single point grounding, thereby eliminating the shared output neutral and 4-pole breakers. Switchgear construction would be simplified, and a UPS service technician would no longer be concerned about isolating the neutral when disconnecting a module from the critical bus.

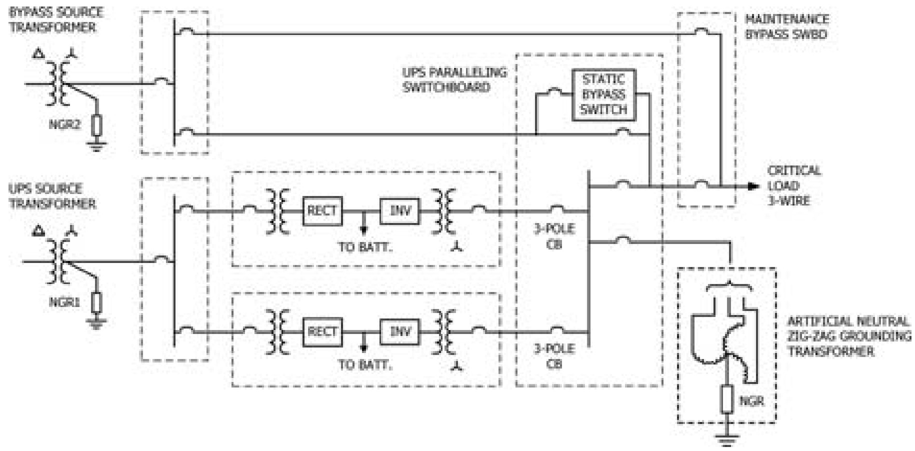


Fig. 8 Proposed Method for High Resistance Grounding of Parallel UPS Systems

Double Ground Fault in HRG UPS Systems

When a ground fault occurs on an HRG system, it should not be left in place indefinitely, but rather repaired within 24 hours or as soon as is practical.

If a ground fault was ignored and another ground fault was to occur on a different feeder and phase, then a phase-to-ground-to-phase fault would result, and both feeders would trip on overcurrent. If a double ground fault were to occur simultaneously on the bypass input and critical load (on different phases), there would be no immediate tripping of either faulted feeder because the two busses are isolated from each other via the static bypass switch. However, if an uninterrupted transfer to bypass were to be attempted, either automatically because of UPS failure or manually by an operator, then the critical load may be put at risk. A phase-to-ground-to-phase fault would occur during the moment the two sources were paralleled via the static bypass switch.

As an added precaution, it is recommended that the UPS system be interlocked with the GF alarm relays of the bypass source and critical load to prevent transfer whenever ground faults appear simultaneously on both busses.

GROUND FAULT MONITORING

A ground fault alarm panel is recommended for each high resistance grounded system to provide alarm indication when a ground fault occurs. This alarm should be monitored by a building management system (BMS) or similar monitoring system so that maintenance personnel can be notified and the alarm logged with a time-and-date stamp.

Furthermore, it is recommended that each feeder of each switchboard in the HRG system be monitored for ground fault.

This practice makes locating ground faults quicker and easier.

Feeder ground fault detection requires a separate zero sequence current sensor at each monitoring point. Residually connected phase current transformers (CT) commonly used in electronic-trip circuit breakers for ground fault sensing on solidly grounded systems are not sensitive enough to detect 1-5 A of ground fault current found in a HRG system.

Multi-feeder ground fault relays are commercially available for installation in switchboards to permit individual feeder monitoring for ground faults. It is recommended that these relays also be wired into the BMS for alarm logging and maintenance notification.

Circuit breakers with ground fault protection are often specified on 600 V solidly grounded systems for feeders 300 A and larger. The trip unit provides long-time, short time, instantaneous and ground fault protection (LSIG). Although LSIG breakers are not sensitive enough to sense single ground faults on an HRG system, they can still serve a useful purpose by providing coordinated ground fault tripping in the unlikely event of a double ground fault. The fault current of a phase-to-ground-to-phase fault is not limited by the NGR, hence will be high enough for sensing by the LSIG trip unit. If one or both of the ground faults is arcing type (not bolted), the LSIG trip units will provide coordinated ground fault protection such that only one feeder may have to trip. If both ground faults are bolted, then both feeder breakers will trip on instantaneous or short-time trip.

CONCLUSIONS

While high resistance grounding offers excellent protection against arcing ground faults and unscheduled shutdown from ground faults, care must be taken when applying to transient voltage surge suppressors and uninterruptible power supplies.

Transient voltage surge suppressors should be rated for use on HRG systems. Three-wire “delta-rated” TVSS are suitable for use on 600 V HRG systems because the L-G MOVs are rated to withstand the voltage rise that occurs during ground fault. TVSS designed for a 3-phase, 4-wire solidly grounded system are not suitable for a HRG system.

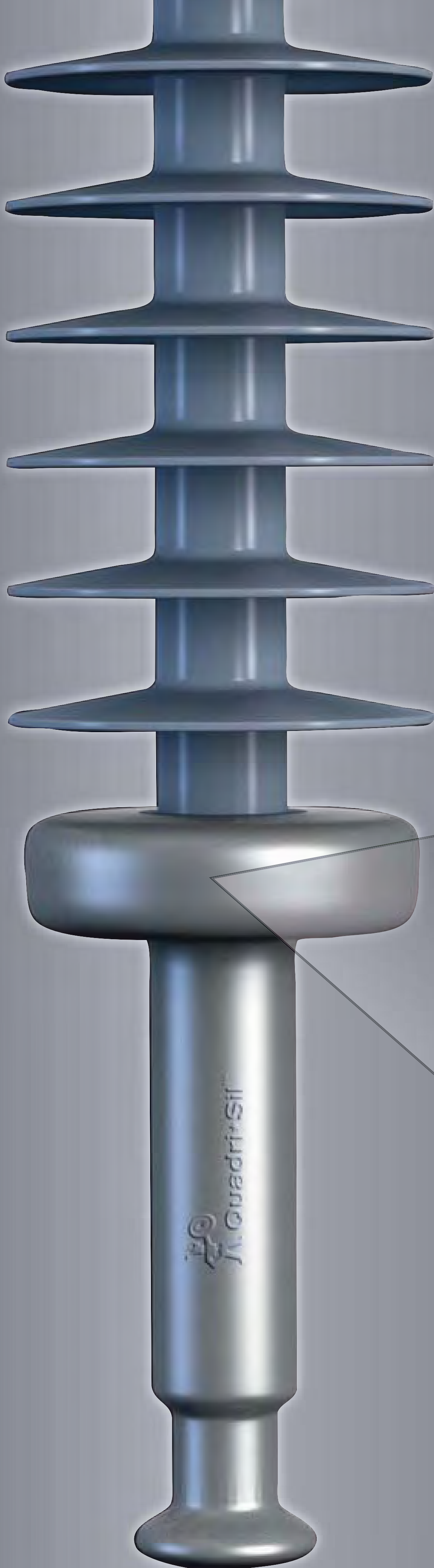
A UPS system intended for a HRG power system should have an internal rectifier input isolation transformer instead of an autotransformer to prevent MOV failure at the rectifier during a ground fault on the input power source.

The UPS 600 V input and output power systems must be grounded the same way, either HRG or solidly grounded.

Mixing the two grounding methods puts the critical load at risk during ground fault. If the critical load is to be solidly grounded yet the UPS is to be fed from a HRG source, then a delta-wye isolation transformer is required at the UPS input to decouple the UPS system from the HRG source. A UPS can be connected to a HRG source only when the critical load can also be HRG.

When parallel three-phase UPS modules with a shared output neutral conductor are high resistance grounded, a switched neutral (typically 4-pole breaker) is required at the output of each module for maintenance isolation purposes. The critical bus neutral becomes energized during ground fault.

It is suggested that UPS manufacturers consider using an artificial neutral zigzag grounding transformer and NGR to high resistance ground a parallel UPS system. This method is widely used to high resistance ground parallel generators and eliminates the need for a switched neutral at the output of each module.



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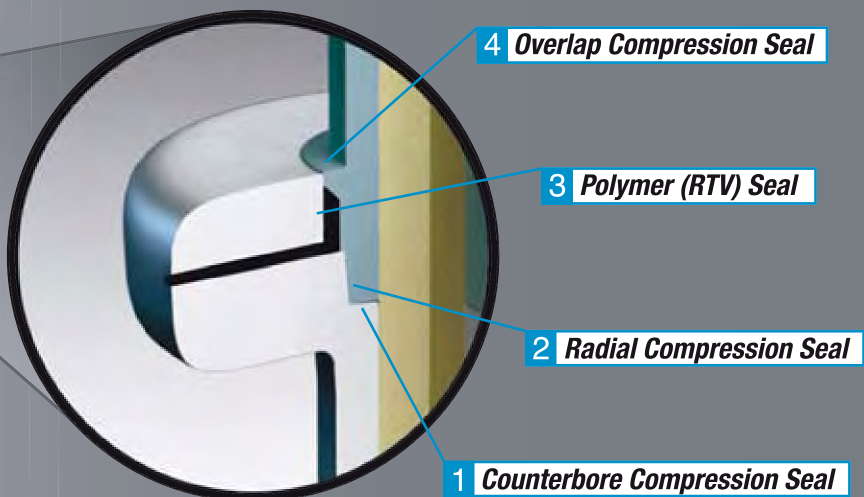

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IMPLEMENTATION OF A WEB-BASED ENERGY AUDIT

By E. Dumont, S. Sansregret, Hydro-Québec; D. Trumble, Enernex

As energy cost continues to grow, utility customers are increasingly interested in ways to reduce their energy consumption. However, few customers have the means to easily identify cost effective solutions to reduce their energy costs. In fact, many customers have no idea where their energy dollars are spent, and for those who think they know, a majority are just misled popular misconceptions.

This article presents a tool that addresses the need for the customer to better understand their energy usage. Taking into account the objectives, we will see the constraints that brought a major electric utility, Hydro-Québec, to implement a deeply customized tool for its customers. Models used by the software will be briefly presented, with a focus on the heating model which is most important in the context of a northern climate utility.

Impressive results obtained by the diagnostic program will also be discussed, exemplifying its success.

OBJECTIVES AND CONSTRAINTS

Objectives

Hydro-Québec (HQ) is a government-owned electric company that serves the vast majority of the Québec territory. The distribution division has approximately 3 million residential customers.

Since many electric utility customers do not have a clear understanding of how they utilize the electricity that they are billed for[1] Hydro-Québec made the decision in 2002 to implement a new tool on its web site to help customers better understand their personal energy consumption.

At the same time, Québec's regulator requested HQ to assist customers in finding ways to reduce their energy consumption. The "Energy Wise" home diagnostic has been designated as the lead tool for this task.

Constraints

In order to be approved as an energy efficiency program for customers, the regulator requested that the diagnostic program be able to make "personalized" recommendations, recommendations that could be customized for each customer. It also had to be available to people without access to the internet, necessitating the availability of a paper survey. For HQ, it was important to have a reliable tool.

Being a government owned entity, HQ's actions are scrutinized and expectations regarding quality of service are high. In addition, with a heating dominant climate and an important share of electric heating, over 65%, the cross-effects of energy savings were a concern.

These cross-effects are caused by the increased heating demand due to the reduced usage within the home thermal envelope. For example, the energy savings from compact fluorescents are generally offset during heating season by the increased heating demand, which constitutes about half of the year in Québec.

With those constraints in mind, research of existing audit tools began and HQ quickly came to the conclusion that there were no products already available which could satisfy all requirements.

The option to customize an existing energy audit tool, the Residential Energy Bill Analyzer (REBA) to meet HQ's needs appeared to be the best solution. Having a strong technical expertise regarding electric home consumption models and working with web product specialists, HQ was confident in implementing a reliable tool which would meet all of HQ's major requirements.

THE DIAGNOSTIC PROCESS

What it is doing?

The first step to understanding the analysis process involves a review of the questionnaire. It is divided into eleven pages: two for basic information (own or rent, detached or not, square footage, etc) and one for each of the nine end-uses to be analyzed. There are over 120 possible questions, but they are selected based on the customer's situation, to limit the number of questions presented. Once completed, the customer has access to a personalized energy diagnostic report. All information for the analysis comes from the customer's billing history, weather data for the customer's area and the questionnaire answers.

The diagnostic report first presents a breakdown of the customer's electric consumption by end use (see table 1). Then the top three saving recommendations are identified to bring the customer's attention to actions that will most reduce energy consumption. The next report sections are organized by end-use category to include all relevant recommendations. Some are best practice recommendations with no specific savings estimates.

Table 1: List of end-uses in Energy Wise Home diagnostic

Heating	Cooking
Air conditioning	Others appliances
Water heating	Lighting
Fridges/freezers	Pool/Spa
Laundry	Unassigned

Other recommendations are more personalized to include savings estimates that are calculated specifically for each customer's situation. When applicable, the analysis takes into account other non-electric energy sources. These other fuel-use estimates appear as a total in the main breakdown table but are disaggregated in each relevant section. Savings calculations for all fuels include both direct and indirect cross effect estimates in order to obtain estimated net savings for the relevant recommendations.

How it works?

One challenge was to develop a heating model that would also take into account the internal gains of other usages. A critical requirement was to use a method to generate reliable and consistent results, even when customer responses are not always consistent. To achieve this goal, both an engineering model and a statistical thermal load model were employed. The engineering model provides an estimate of the heating energy based on dwelling type, square footage, age, other usages and hourly weather information during the analysis period. The statistical model uses a thermal load specification similar to the PRISM[2] approach with an additional component to include other estimated seasonal usages such as seasonal variation of water heating, air conditioning and pool & spa electric consumption. A final heating estimate is then computed as a weighted average of the two approaches, with weights based on the standard error of the statistical model.

End-use consumption estimates for the other non-heating uses are specified as a function of the survey factors and weather data. Electric cooling consumption for homes with central systems is specified as a thermal demand model with thermostat settings for different periods of the day.

For homes with room cooling units, cooling consumption is specified as a function of time used and power capacity. Water heating consumption, for both electric and other fuels, is estimated from hot water usage and water heater tank loss, which is also part of the internal gain estimate used for heating calculations. The remaining usages are based on similar models.

Total end-use estimates for specific billing periods are then compared to actual energy consumption on a bill-by-bill basis. The difference between the actual bill consumption and the corresponding total end-use estimate is referred to as unassigned consumption. End-use estimates are adjusted, within a range determined to be reasonable for the specific end-use category, to reduce unassigned consumption. Adjustment factors have been established for three different confidence levels for each end-use. The adjustment factors for the lowest confidence level provide the largest adjustment range and therefore determine the limit to which unassigned consumption can be reduced. The adjustment factors for the heating end-use estimates are specified as a function of the type of heating and the statistical model standard error. Similarly, the adjustment factors for the Pool and Spa end-use estimates are specified as a function of the type of heating.

If, on an annual basis, unassigned consumption exceeds reasonable limits, a warning message is added to the recommendation report. This message informs the customer that there are discrepancies between the model estimates, which are based on the answers provided and the actual energy consumption. It is advised that the customer review the answers provided.

Once the first end-use section has been completed, approximate results are provided to the user.

A first guess estimate of non-heating and cooling usages is computed based on the number of occupants in the dwelling until the customer has completed the relevant section. This feature allows a consumption graph to be displayed at the top of the page (see figure 1). The consumption graph updates each time a new section is submitted, however, the complete personalized report is only accessible after all end-use sections have been completed.

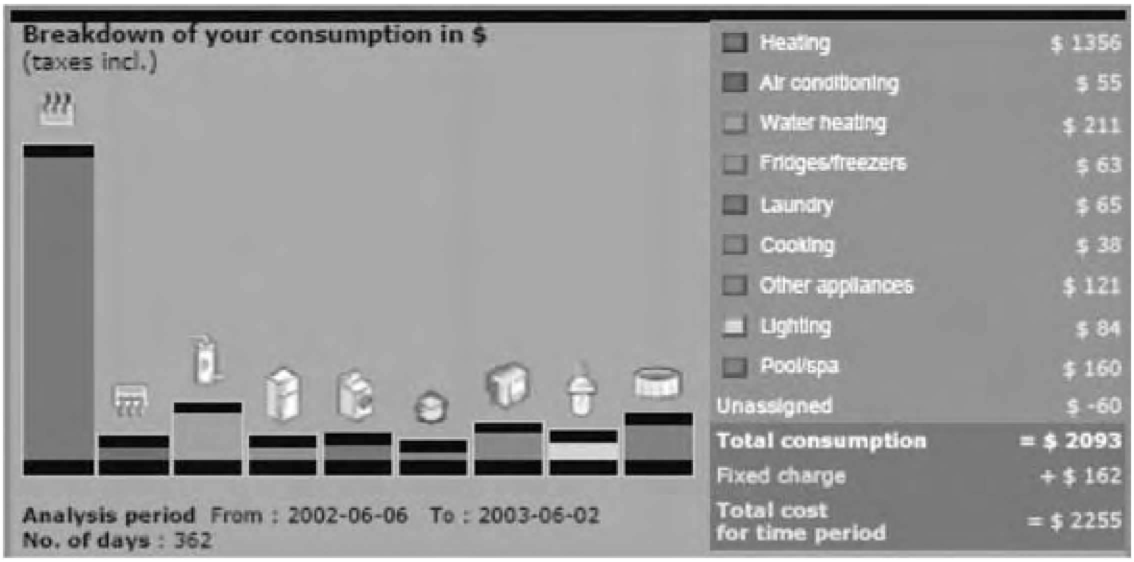

Figure 1: Example of end-use consumption graph appearing at the top of page survey

Recommendations to be included in the final report are derived from the customer's answers to the questionnaire. Quantifiable savings are calculated by one of the following methods:

• A proportional estimate of end-use consumption, or

• A new run of the model utilizing new parameters, relevant to the recommendation.

The second method provides a simple means to calculate the recommendation's cross-effect and is used in most cases. For example, take the recommendation of replacing an old refrigerator. A new run of the model would be performed, taking in to account the consumption of new refrigerator of the same size in place of the older refrigerator. This new run not only provides a new consumption estimate for the Fridge and Freezer end-use, but also provides a new consumption estimate for heating since the new refrigerator will release less heat than the old one. These new consumptions will then be compared with the base case to estimate the potential savings for this recommendation (see Figure 2).

For recommendations involving expenses, a payback calculation is made based on electricity and fuel rates as well as the cost of implementing the recommendation. The recommendation will be displayed only if the payback is below a defined limit (Figure 3). This information resides in a database, making it possible for the Web master staff to adjust rates and costs as required.

The software also includes a simulation tool that is not constrained by historical consumption.

This allows customers the ability to see the energy impact of a "what-if" appliance or of a change in energy usage. This feature is similar to the savings calculation explained above but allows for more than one change at a time. It also allows customers to see the impact of a habit change.

Results

Energy Wise Home Diagnostic made its on-line debut in October 2003. Following a few months of testing, the energy saving program based on the diagnostic was launched in February 2004. In the following months, updates were implemented in order to address a second rate based on temperature (called "DT rate") and to add new features including the "What-if" simulation tool for the customer.

The paper version of the diagnostic was also made available in February 2004. The paper version shares the same calculation engine as the Web version and allows for the option of mass mailing the survey to targeted customers who otherwise may have been unreachable. Once they have the questionnaire in hand, customers still have the choice to go on-line or to fill out the paper survey and send it back. Returned paper questionnaires are scanned and a personalized recommendation report is generated based on the customer's inputs, just as if the web questionnaire has been completed. Customers who have submitted a paper survey also have the option to retrieve their report on their personal page on the HQ website and to evaluate additional "what-if" scenarios.

As of August 2007, over 835,000 diagnostic surveys have been completed by HQ customers.

Over 20% of those were completed via the internet where the rate of completion has been more than 70% (which means that for over 245,000 customers who began to answer the diagnostic questionnaire on the internet, more than 70% completed it). This is a very high rate of completion for an internet survey. Based on a separate HQ survey to measure the impact of the "Home Wise Diagnostic", Hydro-Québec estimates an average gain in 2007 of 309 kWh for each survey completed. This brings the total savings to 270 GWh since the beginning of the program. In addition, the "Home Wise Diagnostic" report provides an effective means to promote other HQ programs.

Energy source	Potential annual savings	Cost	Payback period
Electricity	$ 13 (218 kWh)		
Propane	$ -4		
Total	$ 9		

Figure 2: Example of a recommendation (Disconnect your freezer if not needed) that includes a cross-effect on other fuels. The estimated net savings includes a $4 increase in Propane heating demand and a reduction in electricity saving according that electricity and propane are both used for heating.

Energy source	Potential annual savings	Cost *	Payback period
Electricity	$ 40 (685 kWh)	$ 40	1.0 years

Figure 3: Example of a recommendation (Install a timer on your poll pump) that includes an estimated payback period.

As an example of model accuracy, Figure 4 shows the warning note frequency according to dwelling consumption. As previously explained, a warning note appears on a report if the unassigned consumption is outside an acceptable rate called the "comfort zone" [3]. The warning note frequency is low for dwellings with consumption between 20,000 and 35,000 KWh, which represents the typical consumptions of a single-family dwelling that is electrically heated. Warning note frequency tends to increase for lower consumptions, because the "comfort zone" is smaller since it is based on a percentage of total consumption. In addition, low end and high-end customer consumption may be the result of a non-typical consumer.

Figure 5 shows the relationship between the warning note and the PRISM model fit statistic. We can see that the higher this correlation value, the better the model performs; thus there is less unassigned consumption and therefore fewer warning notes. This tends to show the importance of utilizing a statistical model in the estimation of home heating loads in a northern climate.

CONCLUSION

This article presented a software tool implemented to assist customers to better understand their energy consumption. Starting with specific constraints, the development process resulted in a sophisticated tool capable of providing accurate information to customers, including the cross effect on heating. Valuable recommendations are provided to customers to assist in the reduction of their energy consumption.

At this time, results obtained by the program are quite impressive and meet the expectations of Hydro-Québec, as well as Régie de l'énergie of Québec.

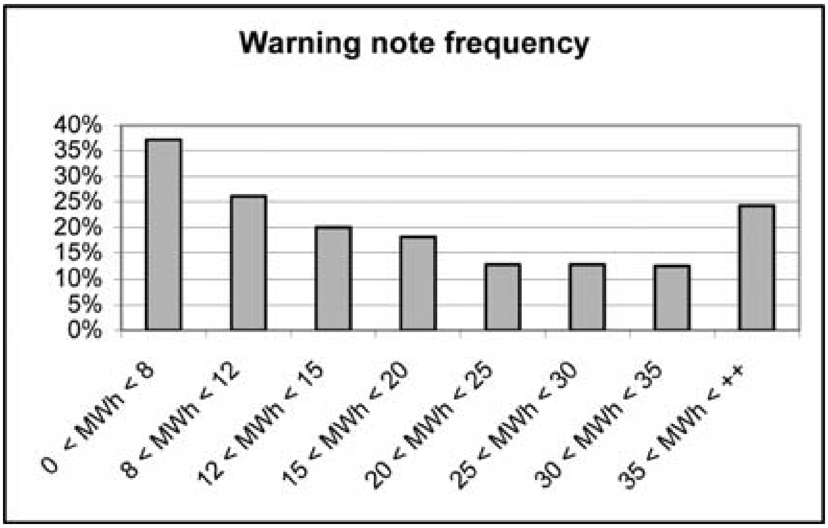

Figure 4: Warning note frequency according to dwelling consumption

FOOTNOTES

[1] In comparison, a telephone bill comes with all the details telling customers how long, when and where calls have been made.

[2] PRISM (which stand for PRInceton Scorekeeping Method) can be briefly described as a statistical non-lin-

ear regression method to model dwelling energy consumption based on billing history and weather data [Fels, M.]

[3] The Comfort zone has been defined as an unallocated consumption of 10% to -3% of customer electric consumption, except for the very small consumer for which we use a comfort based on an absolute value of 300 to -300 kWh

References

Fels, M.; Measuring Energy Savings: The Scorekeeping Approach, Special PRISM Issue or Energy and buildings, 9, #1-2, 180 pages [16 papers describing background on PRISM and sample applications; 1986]

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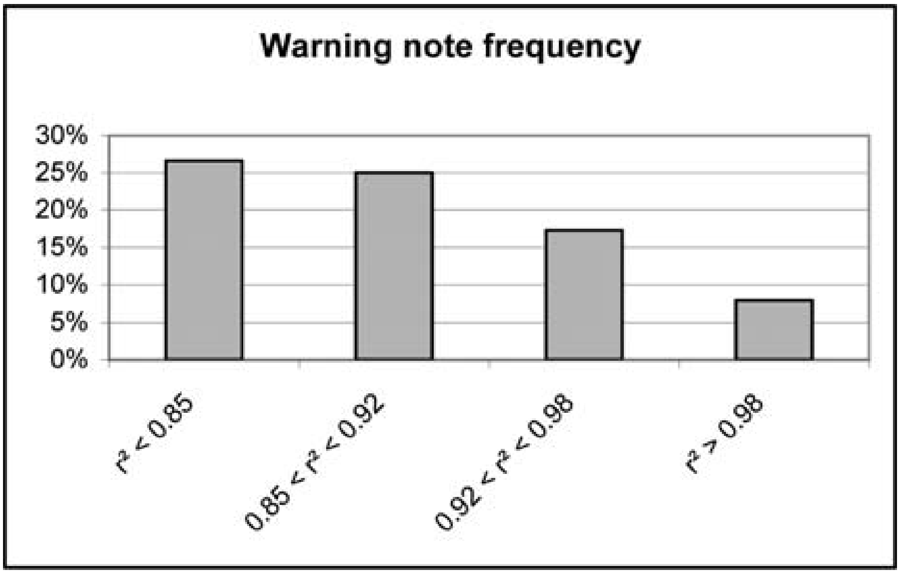

Figure 5: Warning note frequency according to quality of PRISM correlation

INTEGRATING MONITORING AND DIAGNOSTIC EQUIPMENT ON AGING TRANSFORMERS - PART I

By Byron Flynn, Application Engineer, GE Energy

I. ABSTRACT

Valuable information from Monitoring and Diagnostics (M&D) equipment installed on aging power transformers helps utility personnel operate and maintain critical infrastructure.

M&D systems provide valuable online information from power transformers including gas in oil, internal hot spot temperature, insulation aging moisture content in winding insulation, bubbling temperature, and OLTC position tracking. This presentation reviews several methods of integrating M&D equipment to provide this information to SCADA and maintenance systems.

II. BACKGROUND

A discussion of Transformer Monitoring and Diagnostics has a basis on the fundamental construction of a transformer. The transformer is basically a machine consisting of several parts: This discussion, while seemingly overly simplistic, is useful to provide a basis of failure modes and monitoring and diagnostic methods.

The core and coil are the fundamental components of a transformer providing the coupling of magnetic flux between two windings. The core and coils are placed in a tank filled with oil and connected to bushings. The cooling system and control cabinet are the remaining fundamental components of a transformer. Additionally, many transformers in distribution substations include a Load Tap Changer (LTC) that provides additional voltage control on the distribution feeder.

There have been significant efforts to understand the various failure modes of power transformers. Applying the fundamentals of an FMEA analysis consisting of:

- Identify functions
- Identify failure modes
- Identify failure causes
- Identify effects of failure modes
- Identify criticality or risk
- Select on-line monitoring to match characteristic of developing failure cause(s)

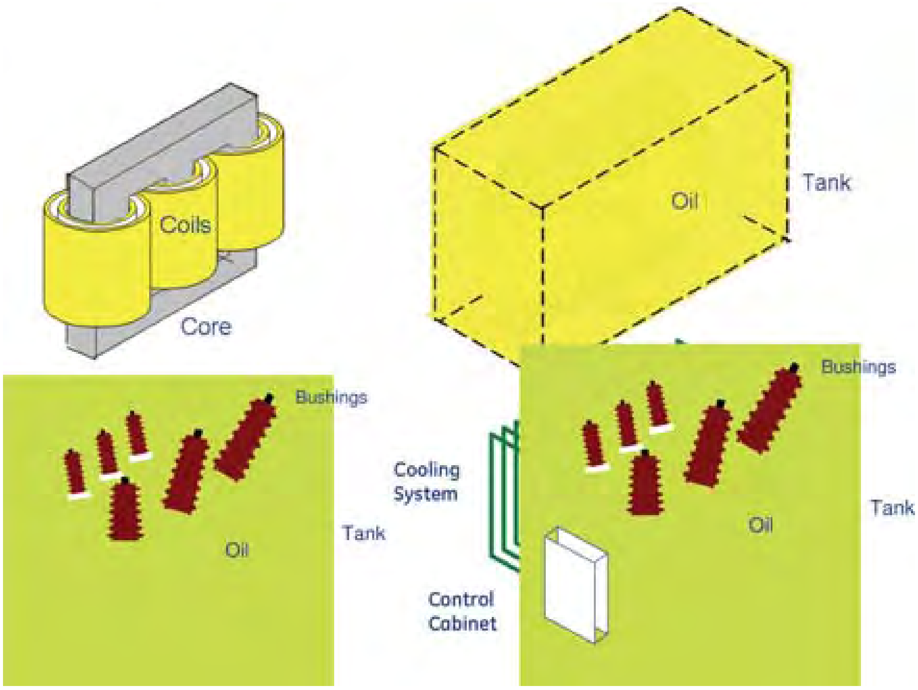

Figure #1: Basics of a Transformer

The analysis of the failure modes of the various components then leads to a review of the inspection and maintenance procedures of power transformers. Then applying Reliability Center Maintenance (RCM) tools to the failure mode analysis information helps a utility design a monitoring system to optimize utilization and eventual life cycle.

Preventive and predictive maintenance:

Reduces the risk and costs of unexpected failure

Actual conditions drive maintenance and repair

Extending life of assets

Reducing costs of maintenance

On-Line diagnostic condition assessment addressing common failure modes:

Multiple sensors

Multiple on-line models

All parameters are recorded automatically and continuously

Trend and limit alarms

On-Line Diagnostics Models

To deal with the potential overload of data, many utilities are installing systems with online diagnostics models. These models were installed to reduce the flood of raw data and to continuously provide information regarding the transformer health and operating history. Additionally, the Dynamic Loading Model provides a guide which can assist

Continued on Page 28

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the dispatchers by calculating the overloading capabilities based on current operating conditions, especially useful during critical times.

Additionally, early detection of problems, at the incipient stage, will help extend the life of the transformer. Detection of these problems is accomplished with several models, which rely on various sensors installed on the transformer and in the substation, combined with other parameters manually entered. This data is then fed into industry standard and accepted models, which calculate the various outputs. These outputs are displayed and trended in the two Master Stations. These capabilities increase the useful data while significantly reducing the shear volume of data. The models focused on the main tank, the LTC and the cooling system and will be described briefly in this section. [1] & [2]

Load Current Model

The first two models use routine calculations. The Load Current Model calculates average and maximum current on each winding based on one-second measurements.

This data is available for display and for trending in the Master Stations. The model's block diagram is shown below.

Apparent Power Model

The Apparent Power Model simply calculates average apparent power (MVA) from the transformer's current and voltage. The average and maximum MVA readings are then displayed and trended. Warnings and alarms are also provided, if limits are reached.

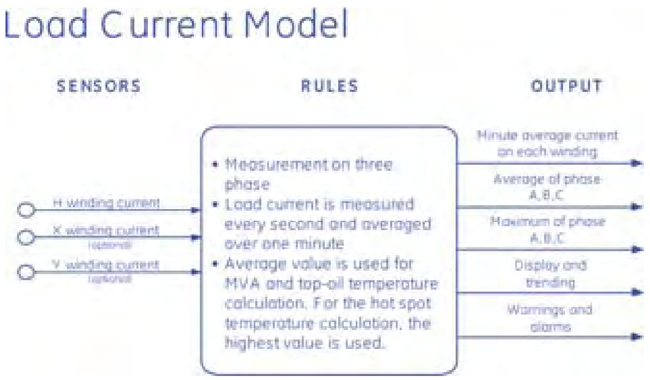

Figure #2: Load Current Model

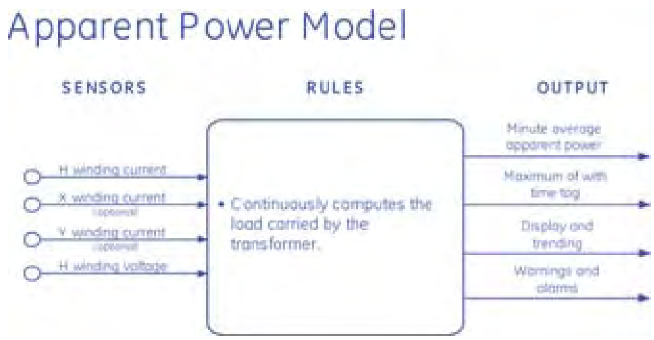

Figure #3: Apparent Power Model

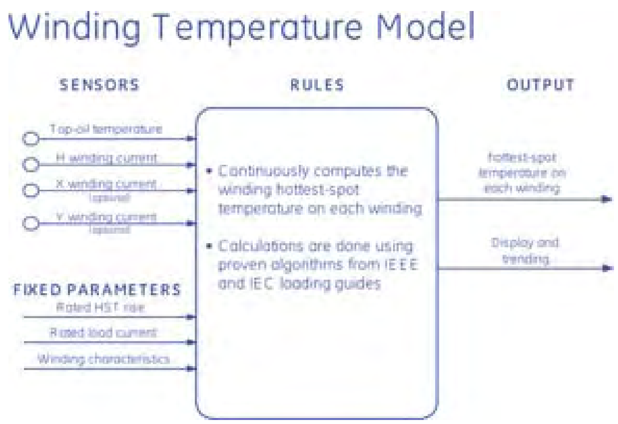

Figure #4: Winding Temperature Model

Winding Temperature Model

The Winding Temperature Model is based on IEEE and IEC loading guides. In accordance with these guides, it calculates the hottest spot temperature on each winding. The values

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Richard Rourk
Supervisor, Fleet Operations
South Carolina Electric & Gas

REGISTER TODAY! (757) 220-1795 • www.eufmc.com are then made available for trend and display on the master stations. The following block diagram illustrates this model's inputs and outputs.

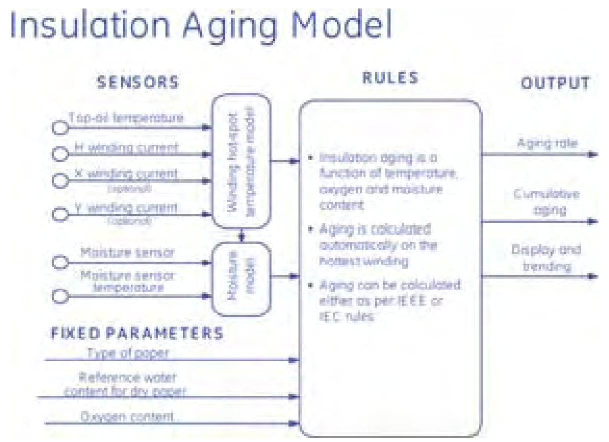
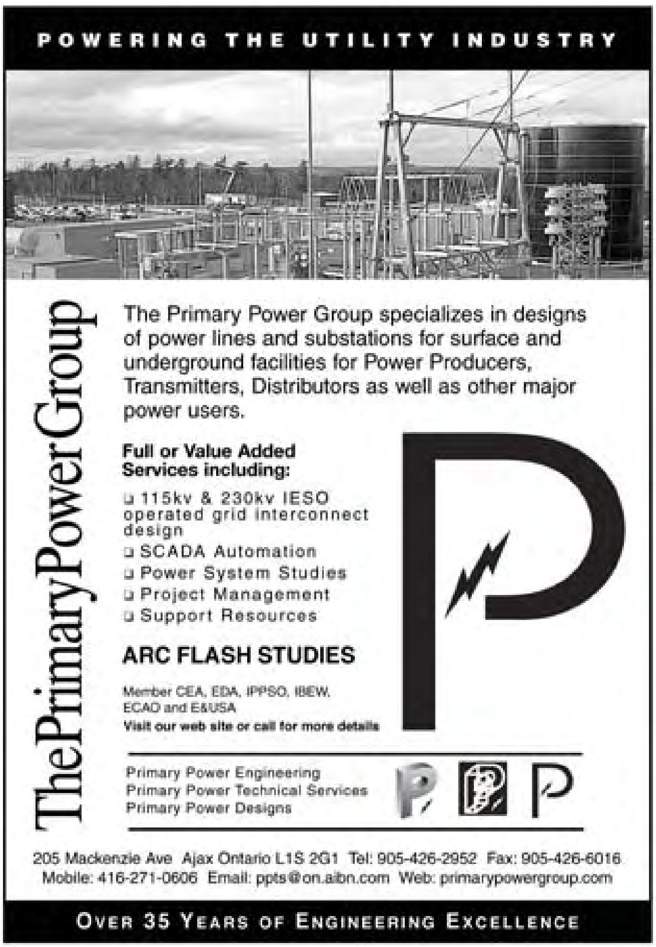


Figure #5: Insulation Aging Model

Computations are carried out according to:

• IEC 354, Loading Guide for Oil-Immersed Power Transformers, Section 2.4, Equation 1



• IEEE C57.91-1995/Cor 1/ July, 2001 Guide for Loading Mineral-Oil-Immersed Transformers, Section 7.2.6, Equation 16, 17, 18

Insulation Aging Model

The Insulation Aging Model calculates transformer aging data based on two different methods, daily & cumulative (IEEE + IEC). The computations are carried out according to:

• IEC 354, Loading Guide for Oil-Immersed Power Transformers; Section 2.6.2, Equation 7, 8

• IEEE C57.91-1995/Cor 1/ July, 2001 Guide for Loading Mineral-Oil-Immersed Transformers; Section 5.2, Equation 2 for 65°C thermally upgraded paper; Annex D, Equation D2 for 55°C normal Kraft paper.

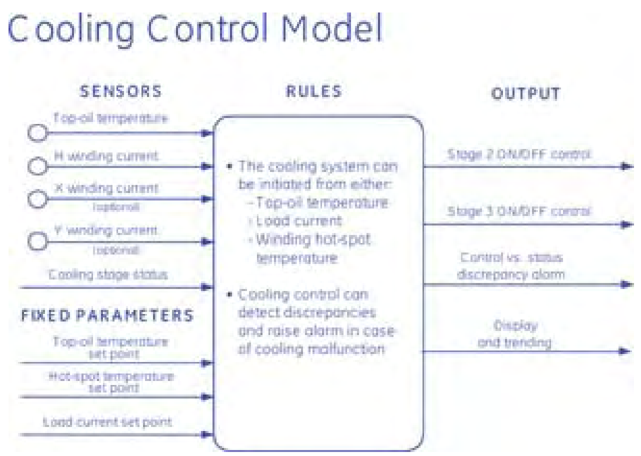


Figure #6: Cooling Control Model

Cooling Control Model

The system can also be used for cooling control using the model described in the block diagram below. The system is used as a backup.

Cooling Efficiency

The Cooling Efficiency Model is used to determine if the Cooling system can lose efficiency over time due to fan failure, physical failure or coolers clogged with pollen, dirt, or nests.

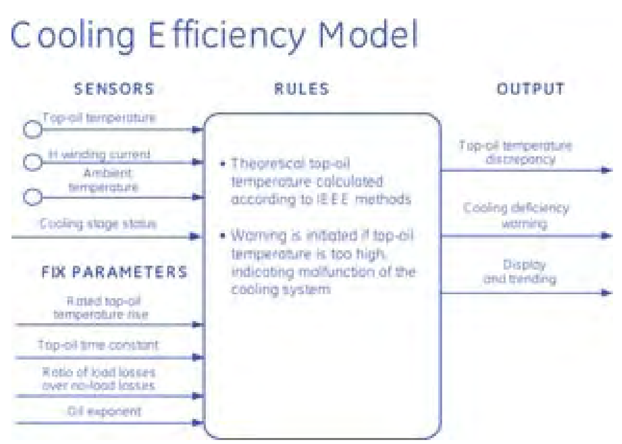


Figure #7: Cooling Efficiency Model

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Aging Transformers

Continued from Page 30

These conditions need to be detected before a transformer overload occurs. The model uses the following calculation methods:

• IEC 354, Loading Guide for Oil-Immersed Power Transformers; Section 2.4.1, Equation 1

• IEEE C57.91-1995/Cor 1/ July, 2001 Guide for Loading Mineral-Oil-Immersed Transformers; Section 7.2.4, Equations 8, 9, 10, 11, 15

Moisture and Bubbling Model

Moisture content of paper is critical because it reduces dielectric strength and increases risk of bubbling at high load resulting in accelerates. The calculations are carried out in line with the following recommended methods:

• T.V. Oommen, "Moisture Equilibrium in Paper-Oil Insulation Systems", Proc. Electrical Insulation Conference, Chicago, October 1983

• W.J. McNutt, G.H. Kaufmann, A.P. Vitols and J.D. MacDonald, "Short-Time Failure Mode Considerations Associated With Power Transformer Overloading", IEEE Trans. PAS, Vol. PAS-99, No. 3, May/June 1980

• T.V. Oommen, E.M. Petrie and S.R. Lindgren, "Bubble Generation in Transformer Windings Under Overload Conditions", DobleÒ Client Conference, Boston, 1995

• V.G. Davydov, O.M. Roizman and W.J. Bonwick, "Transformer Insulation Behavior During Overload", EPRIÒ Substation Equipment Diagnostic Conference V, New Orleans, February 1997

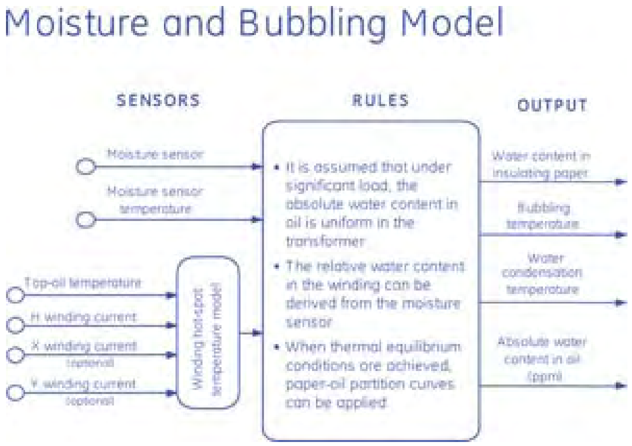

Figure #8: Moisture and Bubbling Model

Tap Changer Temperature Model

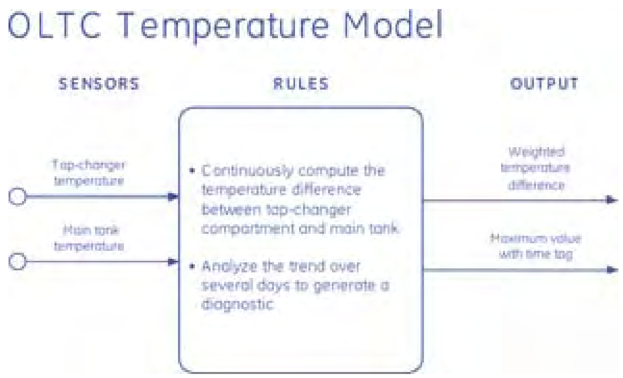

Figure #9: OLTC Temperature Model

Over the life of the transformer, the Tap Changer is a significant source of potential maintenance issues. Many problems with the tap-changer (contact coking) lead to temperature rise in the tap-changer compartment. This failure mode is easily detected by monitoring tap-changer temperature compared

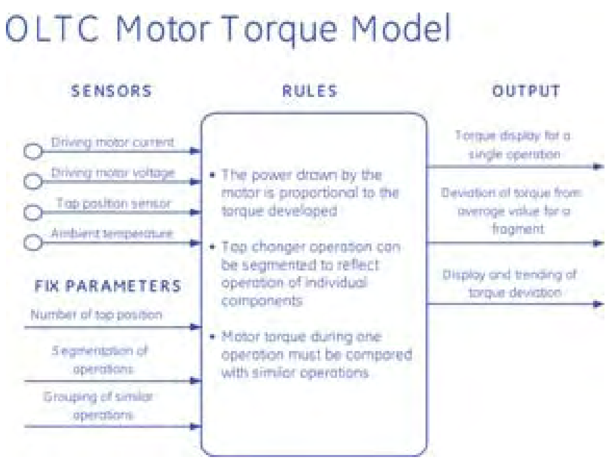

Figure #10: OLTC Motor Torque Model

to main tank temperature.

Tap Changer Motor Torque Model

A change in the motor torque pattern is another indicator of mechanical failures of a tapchanger component. The Tap Changer Motor Torque Model provides a means of detecting a fault in the tap changer, the reversing selector, the gears or energy storage device.

Dynamic Loading Model

The Dynamic Loading Model provides the operators with a perspective of the overloading capabilities, based on current operating conditions. As the load grows in the area, this capability will become more critical in the operation of the transformer.

The Dynamic Loading Model is based on the following models:

• IEC 354, Section 2.4

• IEEE C57.91-1995, Section 5.2 & 7.2.6

See the May issue of Electricity Today for Part II.

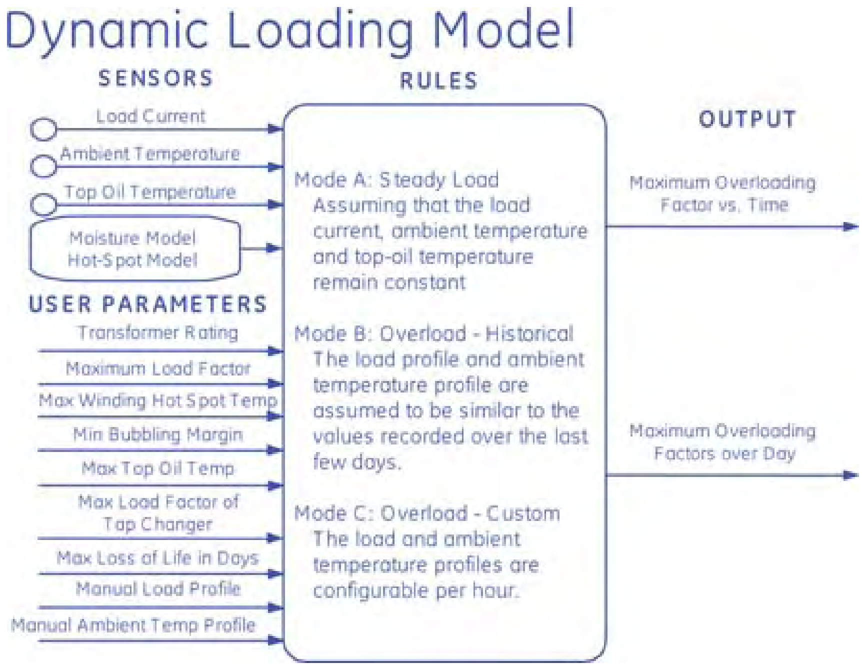

Figure #11: Dynamic Loading Model

THE NEXT STAGE IN METERING: DELIVERING SMART VALUE

By Vineet Kumar, Crompton Greaves Limited

The humble meter is evolving fast. Once a device that simply provided the information to bill a customer, it has been transformed - by competition and by its crucial role in the market - into a key component of energy market infrastructure, and more particularly, to a meter having an Infrared Data Association (IrDA) port.

The need for CO_2 reductions in response to the threat of climate change is compelling governments to raise customers' awareness of energy use. Faced with the raising energy demands of fast growing economies such as India, western nations in particular are concerned about predicting future energy shortages. With fears over security of supply stoked by recent events, governments want to be more self-sufficient in energy.

Existing metering is based on sending regular customer bills and is limited by the cost and speed at which a bill can be printed and posted. If a utility has several million customers, it does not try to send all the bills out at once, but spreads them out over the period between bills. Meter reading is driven by this billing cycle and consists of organizing the reading into 'walks' (a set of meters that can be read by one person in a day) and adds these together so that a meter reader reads meters day after day in the billing cycle. This does not make for fast, efficient billing. The growing insistence of governments that customers are 'read' more frequently and therefore more aware of their energy consumption means that reading has to be a great deal more efficient than this.

IrDA is a standard defined by the IrDA consortium. It specifies a way to wirelessly transfer data via infrared radiation. The IrDA specifications include standards for both the physical devices and the protocols they use to communicate with each other. The IrDA standards have arisen from the need to connect various devices together "connecting each other".

IrDA devices communicate using infrared LEDs, work over distances up to 1.0 m with a bit error ratio of 10-9 and maximum level of surrounding illumination 10 klux (daylight). IrDA defines speeds 0.576 and 1.152 Mbps, with 1/4 mark-to-space ratio. At these speeds, the basic unit (packet) is transmitted synchronously.

An IrDA-based meter needs a way to distinguish between the surrounding illumination, noise, and received signal. For this purpose, it is generally useful to use the highest possible output power, since higher power causes a higher current in the receiver which means a better signal-to-noise ratio. However, IR-LEDs cannot transmit at full power continuously 100% of the time. So, a pulse width of only 3/16 or 1/4 (mark-to-space ratio) of the total time for one bit is generally used. Therefore, it is an aspect of the invention to use IrDA technology to wirelessly transmit and receive data to and from a meter, such as a power and/or energy meter for switchboard and billing applications. These meters are generally mounted at a customer location, on an industrial switchboard panel, and on a utility substation. Data is collected from these meters by a meter reader who takes the data off the meter and writes the data on paper. The data is then entered into a billing or energy management software application.

Data can also be read by a serial or Ethernet connection. However, many of the above-mentioned locations do not have this type of capability. Data can also be read by hard-wiring a mobile computing device to the meter. However, this requires the meter reader to physically locate a connection port and connect wires, thereby making the meter reading process time-consuming.

A meter is provided of the type used for recording data primarily related to power and/or energy use. The meter includes an IrDA port for wirelessly transmitting and receiving data to and from the meter. Preferably, the IrDA port operates according to one or more of the standard IrDA protocols.

The IrDA port is mounted on the face of the meter to allow data to be read using a hand-held computing device. The IrDA port preferably includes components as known in the art, such as a transmitter, a receiver, and a processor storing programmable instructions.

The IrDA port automatically recognizes the presence of the hand-held computing device by intermittently transmitting an optical pulse. If the optical pulse is picked up by the hand-held computing device, the handheld computing device transmits an acknowledgment pulse. The IrDA port then transmits and receives data to and from the hand-held computing device.

The need for CO2 reductions in response to the threat of climate change is compelling governments to raise customers' awareness of energy use.

CCA-PA poles are climbing in lineman popularity

A polymer-based additive (PA), when injected into CCA-treated wood poles, gives a degree of climbability comparable to that of poles treated with pentacholorophenol (PCP). It's no wonder why lineman and engineers are interested!

In 1998 an R&D partnership was initiated by Hydro-Québec with Arch Wood Protection Inc, a US based firm specializing in wood preservatives.

The CCA-PA pole offers the complete benefits of a CCA-treated wood utility pole: *clean, dependable, and environmentally preferable,* plus

- *a degree of climbability comparable to that of poles treated with oil-borne wood preservatives*
- *it is easier to saw, drill and nail than a CCA pole, and*
- *there is nominal storage maintenance -- no need to rotate pole during storage.*

The polymer-based additive is water-soluble in its initial state. It is part of a patented mixture that is injected under pressure into the wood being treated with CCA. The wood is heated and the additive is polymerized to form a three-dimensional network that is water-insoluble.

TESTING

Canada - In February 2000, a series of tests was done as a final part of a 20-month research and testing campaign. During that time a group of control poles was monitored to determine additive retention, pole hardness, degree of climbability and washing out of preservatives. It was concluded that, in summer conditions, the CCA-PA poles were more accepted than the PCP-treated ones, whereas in winter conditions, their acceptability was just slightly below that of PCP.

USA - In the fall of 2006, southern yellow pine (SYP) poles were treated with CCA-PA. Some of these poles were tested with an instrument that measures the climbability index. Index average of 0.82 +/- 0.04 is very comparable to that of red pine PCP poles at 0.76 +/- 0.04, which are normally considered to be softer than SYP PCP poles. Further testing will be conducted to compare with these initial results.

WHERE IS THE CCA-PA POLE NOW?

The CCA-PA pole is approved and listed under the Canadian Standards Association's preservative treatment standard CSA O80.207-05.

The polymer additive chemistry has been adopted by several utilities including Hydro-Québec and Bell Canada, and thousands of CCA-PA poles are now in service.

FOR MORE INFORMATION...

On CCA-PA treated wood poles, contact Arch Wood Protection Canada Corp. in Mississauga, Ontario at 1-800-387-8349.

In the USA, contact Arch Wood Protection, Inc. in Smyrna, GA at 770-801-6600, or visit ...

www.wolmanizedwood.com

ABENGOA SOLAR TO BUILD THE WORLD'S LARGEST PLANT

The Solana Generating Station will use solar trough technology coupled with molten salt thermal energy storage. The plant's rows of mirrors, thermal storage, generating equipment and service areas will cover nearly three square miles. Two 140-megawatt steam generators will produce 900,000 megawatt hours of electricity each year. Operating at full capacity, Solana produces enough electricity to power 70,000 Arizona homes. Graphic: Business Wire

Abengoa Solar, a subsidiary of a multi-billion dollar international technology company, has signed a contract with Arizona Public Service Co. (APS), one of Arizona's leading energy utilities, to build, own and operate what would be the largest solar power plant in the world if operating today.

The plant, scheduled to go into operation by 2011, is located 70 miles southwest of Phoenix, near Gila Bend, Arizona. It will sell the electricity produced to APS over the next 30 years for a total revenue of around $4 billion, bringing over $1 billion in economic benefits to the state of Arizona.

Arizona Governor Janet Napolitano praised the joint efforts of Abengoa Solar and APS. "This is a major milestone for Arizona in our efforts to increase the amount of renewable energy available in the United States," the Governor said. "Arizona is leading the way in protecting our world for future generations through increasing the amount of renewable energy, combating climate change, fighting for air quality and much more. This plant will offer Arizonans a clean and efficient source of energy."

"APS has signed this agreement with Abengoa Solar because of its experience developing and building large solar plants in Spain, Morocco and Algeria," said APS President Don Brandt.

Santiago Seage, CEO of Abengoa Solar, said, "This project not only shows leadership in Arizona and the southwest, but for America. This project will help usher in a new era of large clean and efficient solar power plants. Our commitment to solar energy is global and we will work with utilities, regulators and companies worldwide to make plants like this happen by leveraging the technologies we have been developing over two decades. We continue to advance these technologies in our research and development centers in Europe and the United States."

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Solar plant

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Solana Generating Station uses Abengoa Solar's Concentrating Solar Power (CSP) Trough Technology Abengoa Solar trough technology uses long rows of mirrors which track the sun from east to west in order to best focus sunlight onto the receiver pipes. The receiver pipes are filled with fluid that is heated by the sun's energy, much like a huge magnifying glass. The heated fluid is then sent to a heat exchanger where steam is created, and that steam is then used to turn a turbine. Large insulated tanks filled with molten salt can be used with concentrating solar power (CSP) to store the heat from the fluid. This stored heat can then be used to produce energy during periods of low or no sun, including the evening hours. Photo: Business Wire

The solar plant has been named Solana, meaning "a sunny place" in Spanish. The Solana Generating Station will have a total capacity of 280 megawatts, enough to power 70,000 homes while avoiding over 400,000 tons of greenhouse gases that would otherwise contribute to global warming and climate change.

The plant will employ a proprietary Concentrating Solar Power (CSP) trough technology developed by Abengoa Solar, and will cover a surface of around 1,900 acres. The construction of the Solana Generating Station will create about 1,500 construction jobs and employ 85 skilled full-time workers once completed.

The solar trough technology uses trackers with high precision parabolic mirrors that follow the sun's path and concentrate its energy, heating a fluid to over 700 degrees Fahrenheit and using that heat to turn steam turbines. The solar plant will also include a thermal energy storage system that allows for electricity to be produced as required, even after the sun has set.

"This project is one of the most significant on the planet and it could not have happened without the vision and leadership of APS and its senior management," said Kate Maracas, Vice President of Arizona Operations for Abengoa Solar. "Seldom have we worked with a partner so committed to the future of solar energy and to bringing clean sources of power generation to its customers. We applaud APS for leading the way in bringing long term benefits to Arizona's environment and economy."

With this project, Abengoa Solar reinforces its presence in the United States, where it has been building and operating solar plants that supply industrial steam and heat. Abengoa Solar's objective is to build and operate large solar plants that will supply gigawatts of electric power across the Southwest in collaboration with the leading utility companies.

Abengoa Solar is currently operating the world's first commercial CSP solar tower plant in Spain, a demonstration trough plant and the world´s first commercial photovoltaic low concentration plant. It is also building three more CSP plants in Spain with a total capacity of 120-megawatts, two trough plants that will generate 50-megawatts of electricity each, one tower plant with a capacity of 20-megawats and two hybrid gas-solar plants in Algeria and Morocco.

A subsidiary of Abengoa, a $4 billion multinational company, Abengoa Solar has access to the financial, technical and human resources required to finance, build and operate these large plants.

Abengoa Solar has a team of 40 people in the United States and Spain dedicated to researching, developing and improving solar technologies. In December 2007, the U.S. Department of Energy selected Abengoa Solar for three research and development projects to improve trough technology.

The construction of this solar plant and others under contract in the U.S. are subject to a long-term extension of the solar investment tax credit by the U.S. Congress.

PROTECTION, CONTROL AND AUTOMATION FOR A MULTISTATION LOOPED DISTRIBUTION SYSTEM - PART I

By David Charles, ESCO Engineering and Testing; Ryan McDaniel and Michael Dood, Schweitzer Engineering Laboratories, Inc.

This article describes the protection, control, and automation system developed for a distribution system consisting of 2 generators and 14 substations that are on 3 loops. This project updated the protection and control scheme and added Supervisory Control and Data Acquisition (SCADA) to the site.

The design is based on installing multifunctional microprocessor relays at all remote sites and on the corresponding loop circuit breakers in the 13.8 kV switchgear at the Power Plant. Protection is accomplished using programmable functions in each relay and multicast Ethernet messages to mirror data from one relay to others at adjacent substations on each loop. SCADA is accomplished by directly accessing the Human Machine Interface (HMI) and software provided with the relays. A diesel generator transfer-switching scheme was installed that utilizes existing circuit elements with the installation of new digital generator controls and a second peer-to-peer communication method. Control and supervision of generation operation is provided through the HMI. The communication system is made up of a fiber-optic backbone that runs throughout the complex.

The fiber-optic communication system is the backbone that provides the ability to support the first three of four applications performed by the relay:

1. Distributed Network Protocol (DNP) LAN/WAN to provide SCADA information to HMI's to monitor and operate the facility.

2. Telnet, FTP, and SEL protocol to provide remote engineering access to monitor and set protection devices.

These protocols also allow access to oscillography data, sequential event records (SER), and maintenance data from these devices.

3. IEC 61850 GSSE, also known as UCA2 GOOSE, to provide Permissive Overreach Transfer Trip (POTT) communications.

4. A high-speed, secure protocol is used to perform main bus and tie transfer schemes.

I. INTRODUCTION

A large industrial customer engaged the services of the ESCO Group to upgrade the protection scheme and design a Supervisory Control and Data Acquisition (SCADA) system for its South 13.8 kV Electric Distribution System. This distribution system is similar to those used in many industrial sites as well as large universities. These contracted services included the design, settings, configuration, and commissioning of these systems. The overall project required automating switching and coordination of the loop circuits supplying industrial loads, control and operation of on-site generators supplying power to each loop bus, and control and automation of utility power supply switching, all integrated into one SCADA system with a Human Machine Interface (HMI) for electric department operations. The generator transfer switching for the two 3750 kW generators required installing new electronic engine controls, a new protective relay interface, and integrating the controls into the SCADA network. Communication among devices was designated to be Ethernet using dedicated fibers of the site's backbone system.

The HMI operator information is to be available at any location with Ethernet access to the SCADA network.

In a departure from the typical project sequence of hiring a consultant to design the system, hiring a contractor to purchase materials and install the system, and making the system work after the consultant and contractor have given up, the electric department decided this time the proposed system would be designed, programmed, simulated in a lab environment, and thoroughly demonstrated before installation activities commenced. Furthermore, they wanted to work with a firm that had designed, installed, tested, and commissioned SCADA systems to put all the responsibility associated with the project with one entity. After soliciting proposals from several equipment suppliers whom offered engineering services, the customer selected ESCO Group on the basis of not representing any one particular solution. ESCO Group had demonstrated experience in each aspect of the project and they also had the proximity to support the project after start-up.

The customer's directive to ESCO Group was to use the latest technology with a proven history using as few moving parts as possible that could be maintained with the existing facilities resources. Instead of a "Do it Today" mentality, the customer's philosophy was do it right so that it works when installed.

II. EXISTING ELECTRIC SYSTEM

The customer's electric distribution system is divided into two distinct distribution systems served from two sources by the regional Investor-Owned Utility. A one-line diagram of the south system is shown in Fig. 1. The 13.8 kV switchgear located at the power suppliers Substation U is owned by the customer. As shown in the one-line diagram, the 13.8 kV switchgear is connected in a main-tie-main bus configuration with local backup generation. Breaker 1 feeds Bus 4 from Utility Source 1 while Breaker 11 feeds Bus 5 from Utility Source 2. The tie breaker (Breaker 6) is normally open. Should one of the utility sources be lost, the corresponding main will open and the tie breaker will close to pick up the lost bus. If both sources are lost, the generators connected to Breakers 5 and 7 will

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Looped System

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come online and feed loads. It is also possible to operate the generators in parallel with the utility source if needed for additional load support.

The feeder breakers connected to the 13.8 kV bus feed a looped distribution system with multiple substations that span the customer's site. Each of these distribution substations has a distribution transformer that is connected between two breakers. One of the breakers is fed from 13.8 kV Bus 4 while the other breaker is fed from 13.8 kV Bus 5. While this type of distribution system provides for increased reliability, protection for this looped system requires more care than a typical radial distribution system.

The switchgear was installed during the late 1980s and has been well maintained, but the electromechanical relaying has become outdated. There was no initial provision for remote operation of circuit breakers or data acquisition. Over the years, the residues of various propriety systems installed to collect load flow information have remained. This project provided the opportunity to remove all this legacy equipment.

The remote substations serving the various facility buildings have equipment from a hodge-podge of suppliers. Each loop has grown and been reconfigured as buildings were added or equipment replaced. The electric distribution department can only designate what the configuration of the building electrical supply is to look like. The actual design and selection of distribution equipment is a combination of the engineer/architect hired to design the facility, and the general contractor with the lowest bid to construct the building. Although each substation consists of a breaker on either side of the loop supplying a fused disconnect switch for the building transformer, a variety of manufacturers is represented with protective relaying consisting of the flavor-of-the-day or firesale bargains. Loop coordination is achieved by sequencing time-overcurrent settings, starting from the innermost loop working out to the bus circuit breaker supplying the loop in accordance with a scheme that now only exists in the Westinghouse Electric Corporation Applied Protective Relaying [1]. Coordination has suffered from diminishing time separation of the protective relay settings, failure to apply the coordination philosophy correctly, inconsistent updates of the relay settings to reflect a change, and a multiplicity of relay types and settings. Consequently, outages require the distribution department to first determine where the fault occurred, physically break the system apart, and restore service sequentially until the fault condition is isolated for repair. This often leads to a one- to two-hour outage, which may have been tolerated 20 years ago, but today, arouses the irritation of management.

The existing generator controls consist of several refrigerator-sized cubicles covered on the exterior with lights, dials, switches, relays, and meters, and are stuffed full on the inside

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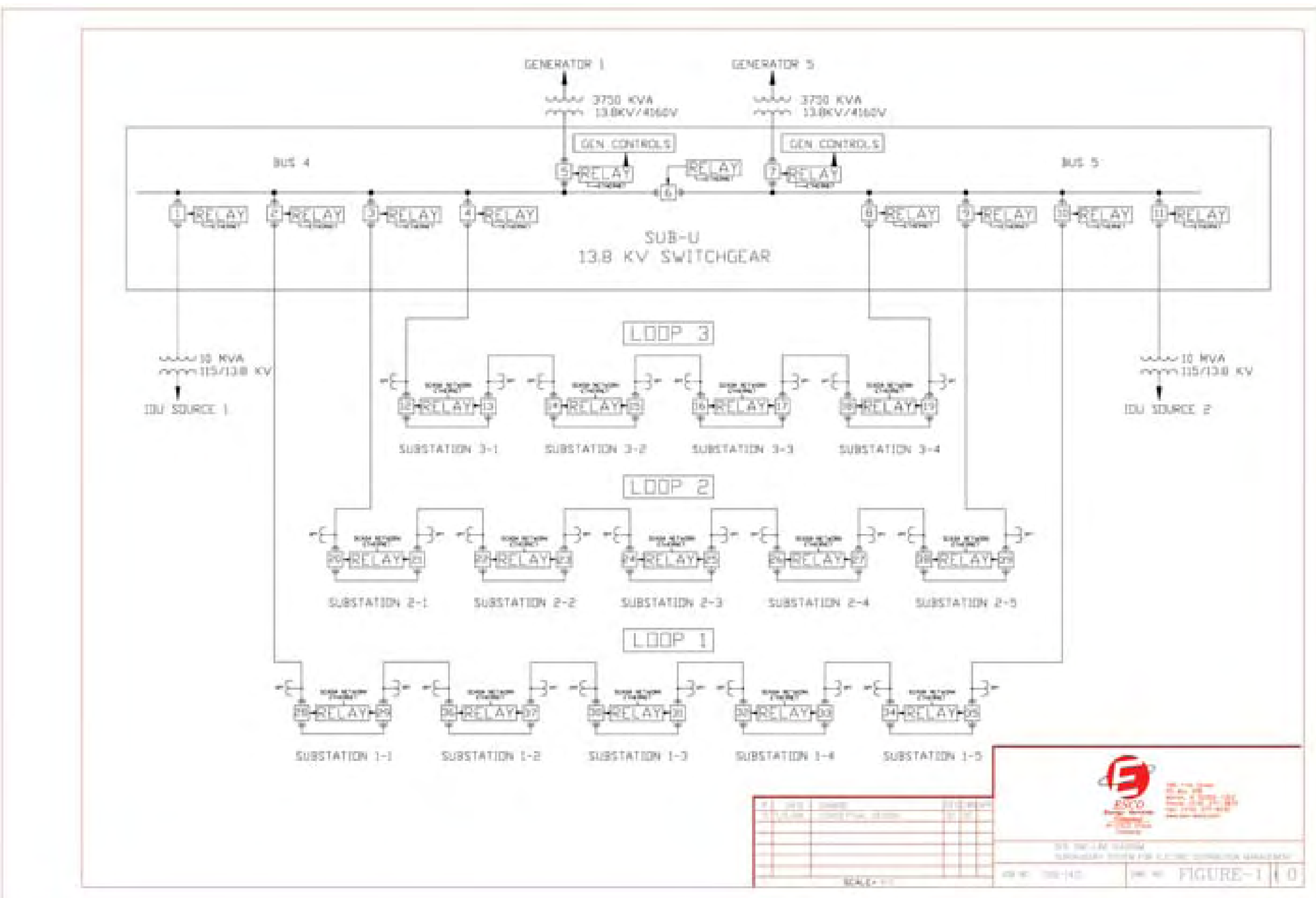

OUTAGE ADVISOR FAULT DETECTION AND LOCATION SOLUTION

By Ted Gardner, Project Manager, Smart Sensor Solutions; Corey Plender, Chief Software Engineer, Cooper Power Systems

THE PROBLEM

For the past three decades, electric utilities have relied primarily on faulted circuit indicators to detect and locate faulted sections of their distribution systems. Although fault indicator technology has provided a reliable means to locate permanent faults, the utility worker still has to physically patrol and inspect the devices. Additionally, many have expressed a desire for the device to differentiate between permanent faults and momentary faults — providing them with valuable information regarding recloser maintenance and vegetation management, their largest operation and maintenance cost. In order to reduce the duration of outages and minimize response time, utilities today are looking for a low-cost communicating device that will relay fault information back to the control center.

Due to regulatory pressure, as well as public relations concerns, improved reliability has become a primary goal for all electric utilities. Utility companies with less-than-desirable reliability rates could be issued penalties such as yearly fines, declines in rate increase requests, or issues with capital planning and funding. This is in addition to how they may be perceived by the surrounding community. Most companies rely on reliability indices such as System Average Interruption Frequency Index (SAIFI) or System Average Interruption Duration Index (SAIDI) to help them determine what circuits or feeders are in need of attention.

Customer complaint reports and reg-

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Looped System
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with relays, transducers, control devices, timers, and more indicating lights, dials, switches, and meters. The modes of operation were intended to support running in parallel with the power source and standby operation for loss of source power. Both generation units do not operate in parallel, even though the same transmission source is supplying both buses, and never seem to operate for a loss of source power.

III. PROJECT STATEMENT

A condensed set of criteria for a new protection and SCADA system are based on the following statements made by the customer:

1. Simplify the protection and control schemes by eliminating a multiplicity of discrete relays and components with one device that can be used to satisfy all required applications. The goal being to reduce training requirements and issues in dealing with different manufacturers. The customer also wanted to reduce the number of protective relay configuration software packages to one.

2. Improve the automatic and manual operations of the system. The existing schemes were either not useful because they were not automatic enough or they were not understood enough by the operators. The requirement of this project was to make these schemes intuitive to eliminate operator mistakes in maintaining the power system.

3. Improve the coordination of the system to eliminate ongoing over-tripping that was being experienced. Thus the requirement was to isolate the fault by dropping the smallest amount of load. They also required that fault location and type data be available without operator intervention from the SCADA HMI to assist them in expediting restoration.

4. Provide the capability to obtain fault event recorder information and sequential event recorder data from anywhere on the SCADA communication network without requiring travel to the relay location.

5. Provide an HMI SCADA system that has two control stations and five view-only stations that can be loaded on a commercial off-the-shelf desktop or laptop computer.

This computer should be able to work from any Ethernet connection on the SCADA communication network. They emphasized that this investment in the SCADA system should be able to be supported for a long time so it should not be a proprietary system.

6. All of the communication protocols must run on the customer's fiber system on a dedicated network using Ethernet topology. It will be maintained by the IT department. It was recognized that there would be different speed requirements for different applications.

For instance, the pilot scheme requires communication speed in cycles while the SCADA HMI requires update times in seconds. It was required that none of the conversations could degrade the overall performance of its application or of any other application.

IV. SYSTEM DESCRIPTION (PRODUCT SELECTION)

To properly protect the electric system reliably and be cost effective, a multifunctional relay with flexible logic, multiple current and voltage inputs, and robust communications was needed. The same device should be used, if possible, to protect, control, and automate the following:

• Automatic main and tie transfer scheme on the 13.8 kV bus

• Generator breaker synchronizing control and generator protection

• Overcurrent protection for the main and tie breakers on the 13.8 kV bus

• Overcurrent protection for the feeder breakers on the 13.8 kV bus

• Directional overcurrent pilot protection for each of the breakers in the small distribution substations

• Overcurrent protection for the transformer in each of the small distribution stations

The relay selected to protect and automate this system had the following capabilities:

• Configurable operator interface with programmable pushbuttons

• Distributed Network Protocol 3.0 (DNP3) and IEC 61850 GSSE Communications

• Ethernet interface

• Relay-to-relay communication with MIRRORED BITS communications

• Flexible logic for both protection and automation functions

• Six AC current inputs and six AC voltage inputs to allow protection and control of two breakers

• Up to 23 DC inputs and 38 output contacts available

• Six configurable time-overcurrent elements

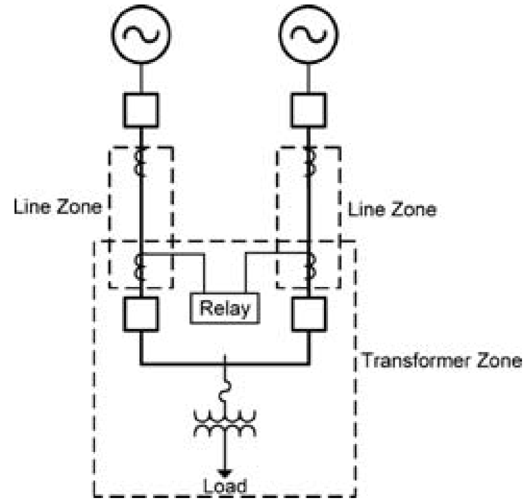

Fig. 2. Relay Protection Zones for Remote Substations

The relay features meet the requirements of remote substation control, protection, and automation. Supervisory control and data acquisition are accomplished by directly accessing the devices through a Wonderware HMI using DNP3 protocol. A software program provided free by the relay manufacturer and loaded on the same computer running the HMI software provides direct access to each relay through the Ethernet SCADA network using FTP, Telnet, and SEL protocols.

Main bus and tie transfer schemes are supported by MIRRORED BITS communications available on each of three serial ports.

Permissive Overreach Transfer Trip (POTT) communications is supported via an Ethernet multicast message (IEC

61850 GSSE, also known as UCA2 GOOSE).

Originally designed as part of the UCA2 protocol suite and given the name GOOSE (Generic Object Oriented Substation Event), the message was merged into the newer IEC 61850 standard and renamed GSSE (Generic Substation Status Event). This was done so that a new message with different capabilities within the 61850 standard could be named GOOSE. Both 61850 GOOSE and GSSE are useful, co-exist on Ethernet networks, and are collectively known as GSE (Generic Substation Events). For the purpose of this specific design, either could have been chosen. Some design selections predated the publication of the IEC 61850 standard and so 61850 GSSE (UCA2 GOOSE) was used. However, if done today, IEC 61850 GOOSE would be recommended. Since both can accomplish this design, further references in this article use the term GOOSE.

A detailed discussion of each aspect of the project follows.

V. REMOTE SUBSTATIONS

At each remote substation, there are three zones of protection: two zones of line protection for each incoming source and one zone of transformer protection that feeds the load at each distribution station. While the transformer is fused, it is necessary to protect the bus that the transformer is connected to as well as provide backup transformer protection.

Conventionally, three relays would be required to properly protect the station and incoming sources. However, the relay chosen has two sets of current inputs and extensive logic available that, when implemented properly, can protect all three zones with only one relay. Fig. 2 shows the three zones of protection that the single relay will protect at each remote distribution substation.

To accomplish the protection needed with one relay, the relay must have the ability to sum currents from each CT to provide transformer protection. Also, each individual CT must be able to protect its respective line as well. Since the line is in a loop scheme, it will be necessary to have a directional comparison scheme on each line to provide the fastest and most secure protection. This will require a directional element for each current input and the ability to communicate with each remote terminal.

The relay selected has settings built in to protect a ring bus or breaker-and-a-half configuration, as shown in Fig. 3. For convention, the manufacturer defines the Breaker 1 current input as IW and the Breaker 2 current input as IX. In this scheme, both current inputs are summed inside the relay to protect the line. However, the internal directional element is also used for this same line protection. So, this configuration allows for protection and metering of the transformer zone using the line protection settings, but it does not offer separate directional overcurrent protection for each line coming into the distribution station.

Fortunately, the relay has flexible logic available that not only includes typical digital logic, but also has the ability to use analog values measured from each voltage and current input. With analog values available for use in the logic, it is possible to create custom protection elements that the user can implement for unique applications. Also, the relay allows the user to select which current quantity the built-in time-overcurrent elements will operate on. There are six available time-overcurrent elements that can be set to operate on the following quantities: line current (IX + IW), Breaker 1 current (IW), or Breaker 2 current (IX). Therefore, an overcurrent element can protect the transformer (IX + IW), another overcurrent element can protect an incoming line (IW), and a third overcurrent element can protect the other incoming line (IX).

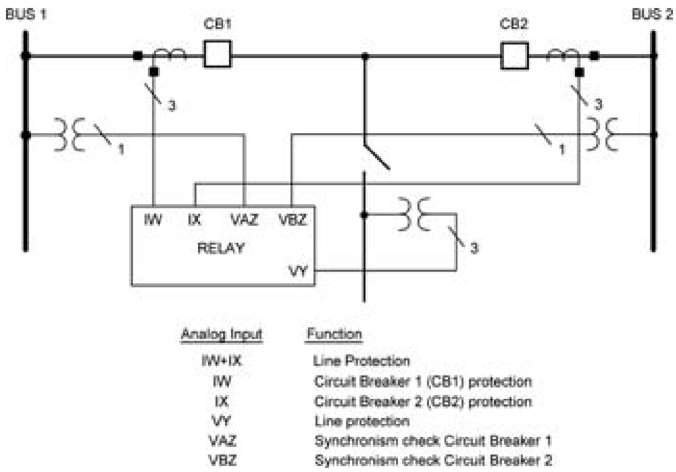

Fig. 3. Example of a Relay Configuration Provided by the Manufacturer

An analysis of the direction current flow during a fault in each of the three protection zones is defined below. For convention, forward current flow for each breaker is defined as current into the distribution transformer. In other words, a transformer fault will produce forward current flow in both breakers. A line fault will produce reverse current flow in the breaker that will clear the fault.

Fig. 4 shows a fault on the remote station bus or transformer.

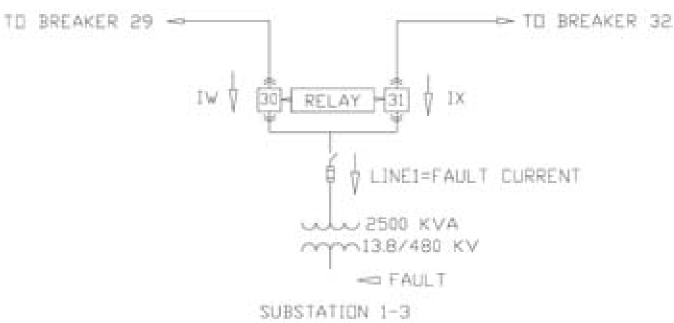

Fig. 4. Fault on Remote Station Bus or Transformer

In this case, the fault current is equal to the relay calculated line current (IW + IX). An overcurrent element (51S1T) will be configured to operate on the line current value and set to coordinate with the fuse for the expected fault current. It will also be set to operate before the feeder breakers on the customer's 13.8 kV bus.

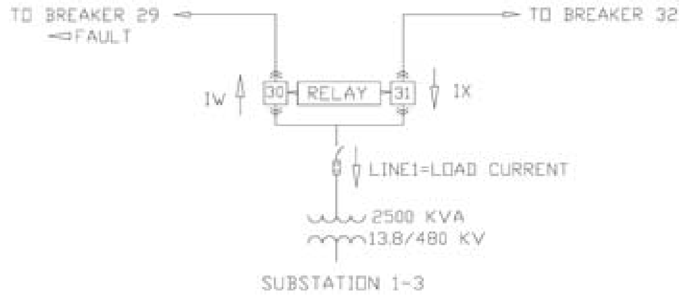

Fig. 5. Fault on Line Protected by Breaker 30

Fig. 5 shows a fault toward Bus 4 in an adjacent line segment.

In this case, current will be in the reverse direction for Breaker 30 but current is in the forward direction for Breaker 31. An overcurrent element (51S4) will be set to send permission on reverse IW fault current and also trip Breaker 30 if permission is received from the remote end.

Fig. 6 shows a fault toward Bus 5 in an adjacent line segment.

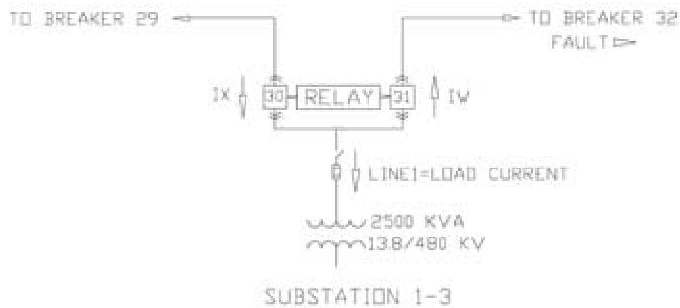

Fig. 6. Fault on Line Protected by Breaker 31

In this case, current will be in the reverse direction for Breaker 31 but current is in the forward direction for Breaker 30. An overcurrent element (51S5) will be set to send permission on reverse IX fault current and will also trip Breaker 31 if permission is received from the remote end.

The overcurrent elements are configured in the standard settings to operate on the appropriate current input value.

Overcurrent element 51S4 is set to operate on the maximum phase current IW. Overcurrent element 51S5 is set to operate on the maximum phase current IX. This essentially sets up two non-directional overcurrent elements that look at the line current each breaker sees in the substation. As mentioned above, non-directional elements will not be enough to securely protect this distribution network.

Since the relay is configured such that the internal directional elements can only be used for transformer protection, an alternative must be developed to directionally control time-overcurrent elements 51S4 and 51S5. The analog quantities and math capabilities of the relay allow the application of traditional phase angle calculations to determine the fault direction of IX and IW. Reference [2] shows a 90-degree connected-phase directional element to be implemented and details the polarizing and operating quantities.

Sonnemann describes the popular 90-degree connected-phase directional element [3]. Table I lists the operating and polarizing quantities of these elements.

TABLE I
INPUTS TO THE 90-DEGREE CONNECTED-PHASE DIRECTIONAL ELEMENT

Phase	Operating Quantity (I_{OP})	Polarizing Quantity (V_{POL})
A	I_A	$V_{POLA} = V_{BC}$
B	I_B	$V_{POLB} = V_{CA}$
C	I_C	$V_{POLC} = V_{AB}$

The following equations represent the torque (TPHASE) calculations for each 90-degree connected-phase directional element:

$$T_A = |V_{BC}| \bullet |I_A| \bullet \cos(\angle V_{BC} - \angle I_A) \quad (1)$$

$$T_B = |V_{CA}| \bullet |I_B| \bullet \cos(\angle V_{CA} - \angle I_B) \quad (2)$$

$$T_C = |V_{AB}| \bullet |I_C| \bullet \cos(\angle V_{AB} - \angle I_C) \quad (3)$$

where:

I_A, I_B, I_C = Phase A, B, and C currents, respectively.
V_A, V_B, V_C = Phase A, B, and C voltages, respectively.
V_{AB}, V_{BC}, V_{CA} = voltage differences $V_A - V_B$, $V_B - V_C$, and $V_C - V_A$, respectively.

Each directional element declares a forward fault condition if the torque sign is positive and a reverse fault condition if the torque sign is negative.

As can be seen from (1)–(3), a torque quantity is generated for each phase using the current and voltage from the other two phases. For a Phase A-to-ground fault, this cross polarization scheme will produce a high torque quantity since Phase A current will be high and the phase-to-phase BC voltage should be unaffected.

Under perfectly balanced voltage and a unity power factor condition, the torque developed for Phase A will be zero. The angle between VBC and IA will be exactly 90 degrees and the cosine of 90 degrees is 0. Therefore, regardless of the magnitude of the VBC voltage or Phase A current, the torque output is zero.

For a forward Phase A-to-ground fault, IA current lags Va voltage, which makes the angle difference between VBC and IA less than 90 degrees. Taking the cosine of an angle less than 90 degrees will produce a positive torque value. For a reverse Phase A-to-ground fault, IA current leads Va voltage, which makes the angle difference between VBC and IA more than 90 degrees. Taking the cosine of an angle greater than 90 degrees will produce a negative torque value. In summary, a positive torque is current in the forward direction; a negative torque is current in the reverse direction.

The cosine operator determines the directionality or sign of the torque value, but the magnitude of voltage and current multiplied together give the torque its magnitude. It can be seen that for a Phase A-to-ground fault, the torque value for Phase A will be much larger than the torque values for the unfaulted phases. In general, the phases involved in the fault will generate the largest torque values.

In an electromechanical scheme with directional torque control, each phase had a dedicated overcurrent element that was controlled by its directional polarizing quantity.

Therefore, if there was a forward Phase A-to-ground fault, only the Phase A relay could operate for the fault because it was the only phase with enough current to spin the induction disc. Even though the induction disc may not have spun on the two unfaulted phase overcurrent relays, the directional torque control may have still determined a direction, and quite possibly, the wrong direction. During a Phase A-to-ground fault, the unfaulted phases, which are still carrying load, are unreliable and cannot be used. Due to this, the torque quantity of the faulted phases must be used in determining the direction of the fault.

In a digital relay, all three phases are available which can sometimes lead to unexpected problems. The overcurrent element being used in the digital relay is a three-phase element, which means it asserts if any phase current becomes greater than the set point. Once that overcurrent element asserts, the faulted phase(s) are not known, therefore, the torque quantity that needs to be used is also not known.

One way to solve the problem is to set up a “fault detector” in the logic. This would require taking the pickup setting of the overcurrent element and putting it into the logic to supervise the torque control. This would operate similar to the electromechanical scheme mentioned earlier where only the torque of the faulted phases is used. The disadvantage of doing this is that the overcurrent pickup setting must now be entered in the logic. It is conceivable that this setting could be forgotten or not updated properly as new settings were issued and lead to undesirable operation of the directional element.

Another option is to compare the torque quantities the relay calculates during the fault and use the largest absolute torque value to determine direction. By using the torque comparison method, no additional fault detectors are needed, and more importantly, the faulted phase(s) will determine the direction of the fault. The logic for winding IW is shown in Fig. 7 (the logic for winding IX is similar).

Notice that lines PROTSEL28–PROTSEL30 match the formulas given for the 90-degree connection in (1)–(3). The manufacturer defines the following analog quantities that are used in this application as follows:

• VBCYM, VCAYM, VABYM: Phase-to-phase filtered instantaneous voltage magnitude in volts secondary

• IAWM, IBWM, ICWM: Terminal W phase-filtered instantaneous current magnitude in amps secondary

• VCBYA, VCAYA, VABYA: Phase-to-phase filtered instantaneous voltage angle in degrees

• IAWA, IBWA, ICWA: Winding (IW) filtered instantaneous current angle in degrees

To add security to the directional element, the operate time of any instantaneous element must be delayed one cycle to allow time for the relay's filtered values to determine the proper fault direction.

This directional element was tested for common type faults in the lab using system impedance values from the customer and operated reliably. However, a close-in three-phase fault can disable the directional element since there is no voltage memory polarization and backup tripping will be needed to clear this type of fault. Roberts and Guzman also detail the possibility of 90-degree directional element misoperation if only a zero-sequence source is located behind the relays [2].

```
PROTSEL24   #PSV10 INDICATES BUS VOLTAGE IS NOT HEALTHY FOR POLARIZATION
PROTSEL25   PSV10 := VABYM < 1 AND VBCYM < 1 AND VCAYM < 1

PROTSEL26   #TORQUE IS POSITIVE IF FAULT IS FORWARD
PROTSEL27   #TORQUE IS NEGATIVE IF FAULT IS REVERSE

PROTSEL28   PMV01 := VBCYM * IAWM * COS(VBCYA - IAXA) #TORQUE A
PROTSEL29   PMV02 := VCAYM * IBWM * COS(VCAYA - IBXA) #TORQUE B
PROTSEL30   PMV03 := VABYM * ICWM * COS(VABYA - ICXA) #TORQUE C

PROTSEL31   #FIND THE ABSOLUTE VALUE OF EACH TORQUE
PROTSEL32   PMV04 := ABS(PMV01)  #|TORQUE A|
PROTSEL33   PMV05 := ABS(PMV02)  #|TORQUE B|
PROTSEL34   PMV06 := ABS(PMV03)  #|TORQUE C|

PROTSEL35   #FIND THE LARGEST ABSOLUTE TORQUE
PROTSEL36   PSV04 := PMV04 >= PMV05 AND PMV04 >= PMV06 #|TORQUE A| IS LARGEST
PROTSEL37   PSV05 := PMV05 >= PMV04 AND PMV05 >= PMV06 #|TORQUE B| IS LARGEST
PROTSEL38   PSV06 := PMV06 >= PMV04 AND PMV06 >= PMV05 #|TORQUE C| IS LARGEST

PROTSEL39   #DETERMINE IF THE LARGEST |TORQUE| IS NEGATIVE
PROTSEL40   PSV07 := PMV01 < 0 AND PSV04 #TORQUE A IS NEGATIVE AND LARGEST
PROTSEL41   PSV08 := PMV02 < 0 AND PSV05 #TORQUE B IS NEGATIVE AND LARGEST
PROTSEL42   PSV09 := PMV03 < 0 AND PSV06 #TORQUE C IS NEGATIVE AND LARGEST

PROTSEL43   #IF PSV11 ASSERTS, THE LARGEST |TORQUE| IS NEGATIVE
PROTSEL44   PSV11 := (PSV07 OR PSV08 OR PSV09) AND NOT PSV10

PROTSEL45   #ADD A DEFINITE TIME DELAY TO THE OC ELEMENT
PROTSEL46   PCT01IN := 51S4
PROTSEL47   PCT01PU:= 1 #ADD A ONE CYCLE DELAY

PROTSEL45   PSV02 := PCT01Q AND PSV11 #FAULT DETECTED IN THE REVERSE DIRECTION
```

Fig. 7. Directional Element Logic

In this distribution system, however, it is highly unlikely that a zero-sequence-only source could become available. Also, for a very high, resistive phase-to-ground fault, the largest torque quantity may not be on the faulted phase. However, this type of fault would be very difficult to detect with traditional overcurrent elements and is not considered a problem in this application since only phase overcurrent elements are being used. Sensitive ground overcurrent elements would require additional design and testing.

As can be seen, the performance of any directional element must be evaluated before applying it to a certain system. In this system and scheme, the shortcomings of the element should not affect the reliability or security of the scheme.

However, in another system or another scheme, this element may be deemed unacceptable for use.

VI. IMPLEMENTATION

From the logic in Fig. 7, it can be seen that PSV02 is the reverse fault detected bit. When this bit is combined with a permissive signal supplied by GOOSE messaging from adjacent relays, the breaker will trip. PSV02 is also used to generate GOOSE messages to be sent to the relays in the loop multicast group as a permissive to trip in the POTT scheme.

Fig. 8 (in part 2) shows how the whole scheme works.

For the fault in Fig. 8, the objective is to open Breakers 15 and 16 to isolate the fault. When Breaker 4 sees fault current, the backup time-overcurrent setting is picked up and begins timing. Breaker 12 is not sending a GOOSE message to trip Breaker 4 because the fault current is in the forward direction, not the reverse as defined earlier. Through GOOSE messaging, Substation 3-1 is indicating a through fault and Breaker 13 is telling Breaker 14 it's got a reverse fault current and is looking for permission to trip. Substation 3-2 is indicating a through fault, and Breaker 14 is not sending a GOOSE message to Breaker 13 to trip because the current is in the forward direction. Breaker 15 is indicating a reverse direction fault and is sending permission to Breaker 16.

See the May issue for Part II

HELPING MEET ISO-NE CAPACITY NEEDS THROUGH DEMAND RESPONSE

By Nick Planson and Bill Cratty, ConsumerPowerline

In late 2006, Stanley Works was contacted by ConsumerPowerline to enroll its Connecticut manufacturing facilities in demand response programs offered by the Independent System Operator of New England (ISO-NE).

ISO-NE, as part of its commitment to promoting regional grid sustainability, offers programs that provide significant financial incentives for end users of electricity to curtail - or reduce - their electricity during times of electric grid stress, high electricity prices or emergency situations. These range from programs that require participants to curtail within 30 minutes of notification, to a Demand Response Reserves program, currently in its pilot phase, which requires participants to curtail within 10 minutes, but has much shorter events.

At first, Stanley Works' staff was hesitant to participate in a demand response program. They were concerned that it might adversely affect manufacturing operations and overall ability to carry out its core business. Stanley Works is in the business of making tools – not running an electric grid. After several meetings with ConsumerPowerline, Stanley Works felt that the flexibility of the ISO-NE's programs, coupled with its attractive incentives, made participation viable, sensible, and socially responsible. Stanley Works' decision to participate was motivated not solely by the financial benefits of program incentives and energy savings; its concern over the increasingly fragile electric system, particularly in Connecticut, led the firm to enhance its corporate citizenship.

After an orientation regarding the program options, followed by a detailed engineering assessment performed by ConsumerPowerline in close collaboration with Stanley's facilities and operations management teams, an initial curtailment plan was developed for the ISO-NE's 30-Minute program. This first plan was conservative and structured so that any reduced load would not affect production processes or overall operations. Under the 30-Minute program, if the ISOTNE experiences an electrical emergency, Stanley is required to drop load within 30 minutes of notification, for up to four hours. The ISO-NE typically only experiences one electrical emergency per year.

With its curtailment plan in place, and its partner, ConsumerPowerline, available for support and risk management, Stanley Works enrolled in the ISO-NE's 30-Minute program, ready to shed load whenever New England's electric grid needed some extra capacity. Additionally, Stanley Works realized that taking such a close look at its energy usage would help it find new flexibility in its processes, and could pave the way to increased energy efficiency and, ultimately, permanent load reductions and savings to them.

> Stanley Works is in the business of making tools – not running an electric grid.

Once Stanley Works' staff became comfortable with the logistics of the ISO-NE's 30-Minute program, they started looking for ways to increase their participation. With ConsumerPowerline's support, Stanley Work's staff identified additional load reductions at its primary and secondary facilities. The Company even considered implementing a full plant shutdown during the most vital demand response events. Because Stanley Works could reduce a significant amount of load without a full plant shutdown, this did not become a part of their curtailment plan. Instead, Stanley Works decided to expand its participation by enrolling in the ISO-NE's new Demand Response Reserves (DRR) Pilot program.

The ISO-NE implemented the DRR Pilot program to explore whether demand response could help cover short-term electric capacity shortages. The DRR Pilot requires participants to respond within 10 minutes of receiving notification. Events occur much more frequently, though they typically last about half an hour. From the end user's perspective the DRR Pilot offers significant opportunities, but also some challenges. For example, DRR Pilot events are much shorter, and the end-user can participate in both the DRR Pilot and the 30-Minute program, achieving an additional demand response revenue stream and protection for the electric grid. On the other hand, events are more frequent and response time is shorter, frequently making automated controls necessary. Thus, for the right facility, the DRR Pilot is an excellent option; for other facilities, the requirements are too strenuous.

In Stanley Works' case, the DRR Pilot was a perfect complement to its participation in the standard 30-Minute program. Because of its success, the company identified a second facility that was well-suited for the DRR Pilot and could accommodate the program's frequency and duration. To date, Stanley Works has responded to all DRR Pilot events and has met its committed levels of reductions, demonstrating that demand response resources can respond just as quickly and reliably as a power plant.

Stanley is now looking for new ways to reduce year-round energy consumption. One opportunity of great interest are new incentives available through the ISO-NE's Forward Capacity Market, which allows energy efficiency, load shifting, and distributed generation to receive market-based funding, at the same dollar amounts per kilowatt as power plants. Stanley and ConsumerPowerline believe that this could be a lucrative opportunity for the company going forward.

Stanley Works' participation in the ISO-NE's 30-Minute and DRR Pilot programs proves how, through demand

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Demand Response
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response, industrial facilities can benefit both the increasingly constrained electric grid and themselves. Since industrial facilities' staffs thoroughly understand their processes, production lines, and operations, they can quickly identify flexible electricity loads.

With reasonable notice, manufacturers can schedule shift changes, production line reductions and manpower around demand response events, with the option of shutting down most, or all, of the load at a given facility. Additionally, because energy is a significant cost component, facilities will benefit from advanced energy management systems perfect for demand response, for the facility itself, and for helping keep the lights on throughout the state or city.

YOU SAID IT

Mike Malik, a Senior Engineer with Entergy in Kenner, Louisiana, says Electricity Today provides "excellent information".

Mary Slovachek, a Research Technician III with Cooper Power Systems in Franksville, Wisconsin, says she found Electricity Today while "looking for magazines – information – to stay current on trends in equipment and materials for use in (the) power distribution industry."

Michael Giordano, Technical "Services Manager with S. Norwalk Electric & Water in North Branford, Connecticut says "fantastic magazine!"

Lawrence Rudolph, a Senior System Control Operator with the City of Lethbridge in Alberta, writes "thoroughly enjoy your magazine. Very informative."

Edward Fatherly, a Senior Electrician with the U.S. Army corps of Engineers in Russellville, Arizona writes "Very useful magazine!"

Clint Whitney, an Electrical Systems Supervisor with the City of Richland in Richland, Washington says that he "Always appreciates the balance between technical and new product articles."

Glenn Cunningham III, a Safety Coordinator with Diverse Power in LaGrange, Georgia says "I have been receiving and seen your magazine for years now and am always impressed by the information contained. You do a great job. Please keep up the good work!"

Chandrasekara Sankaran, Principal Electrical Engineer with Power Science Engineering in Shoreline, Washington writes "Your magazine is extremely useful to practicing electrical design/consulting engineers. Thank you."

HOW TO COORDINATE TRANSFORMER PRIMARY-SIDE FUSES WITH FEEDER RECLOSERS

PART I: CONSERVATIVE METHOD

In part I, we explain how to coordinate transformer primary-side fuses with a secondary-side automatic circuit recloser, such as in a utility substation.

We'll use the "conservative" coordination method, which ignores the effects of fuse cooling during the reclosing time intervals (contacts open) of the recloser.

SOURCE-SIDE FUSE/LOAD-SIDE RECLOSER COORDINATION

Automatic circuit reclosers sense overcurrents, interrupt them, and then automatically reclose to reenergize the feeder. Most faults on overhead distribution systems — perhaps as many as 75 to 80% — are temporary in nature, lasting only a few cycles to a few seconds.

With their "trip and reclose" capability, reclosers eliminate prolonged outages on distribution systems due to such temporary faults. If a fault is permanent rather than temporary, however, the recloser will "lock out" after a preset number of reclosing attempts (usually three or four), thus isolating the faulted feeder from the system.

Automatic circuit reclosers have dual timing capabilities which help maintain coordination with other protective devices and limit the areas affected by permanent faults. Typically the first — sometimes the first two — fault-clearing operations are performed per the "fast" timing characteristic, clearing temporary faults before load-side protective devices operate. Subsequent operations incorporate a predetermined time delay that allows protective devices nearer the fault to interrupt permanent faults, thereby limiting the extent of the service interruption.

This arrangement is often referred to as a "fuse saving" scheme, since fuses only respond to permanent faults within their zones of protection.

For the application covered in this article, the transformer primary-side fuse is located upstream of the automatic circuit recloser. The goal is that the fuse not melt before the recloser operates to lockout in response to a permanent fault. The maximum fault current value up to which the fuse and the recloser will coordinate is generally the lower of:

1. The maximum interrupting capacity of the recloser or fuse, or

2. The intersection of the minimum-melting curve of the fuse and the maximum-equivalent operating curve of the recloser (i.e., the "lockout" curve).

In the conservative coordination method, cooling of the fuse during reclosing time intervals (contacts open) is ignored. You simply sum the heating effect, or heat input, of each recloser operation. That is, the lockout curve of the recloser is developed by summing the total clearing times for the proper number of fast and slow operations, at various current levels, per the following equation:

$$T_l = \frac{\sum_{j=1}^{n} T_{Rj}}{1-P}$$

Where:

Tl = Point on the maximum equivalent lockout curve of the recloser, at selected current (I).

P = Reduction in the melting time of the fuse due to preloading, expressed as a decimal part of its total melting time.

TRj = Maximum clearing time at current (I) for the jth operation (contacts closed) of the recloser.

n = Number of operations (contacts closed) of the recloser.

Since the fuse must allow the recloser to operate to lockout without melting, the recloser's maximum equivalent lockout curve should be developed. Recloser fast curves (A) are typically published to maximum test points. But slow curves (B, C, and D) are published to nominal test points and must be adjusted (maximized) by the amount of the positive tolerance, which is assumed to be 10%.

EXAMPLE

Consider a rural electric power substation having a single transformer, protected by fuses, with three or fewer feeder reclosers. Ratings for the primary-side fuse, the transformer, and the load-side reclosers are as follows:

Transformer: The transformer has a base (OA) rating of 7500 kVA three-phase, 115 kV primary, 13.2 kV secondary. It has a forced-air (FA) rating of 9375 kVA (125%). The transformer impedance is 7.5%, and the maximum three-phase secondary fault current is 478 amperes (2000 MVA), as seen on the primary side of the transformer. The transformer is connected delta grounded-wye.

Fuse: The primary-side fuse is a 65E-ampere Standard Speed S&C SMD-2B Power Fuse rated 115 kV. The full-load current of the transformer, based on its force-air rating is 47 amperes. At this level of transformer loading, the fuse will be loaded to 72% of rating (47 amperes ÷ 65 amperes = 0.72). The preload adjustment factor, as determined from S&C Data Bulletin 210-195, is 0.88.

Feeder Recloser: The load-side recloser is a hydraulically controlled Cooper Type W Recloser, rated 14.4 kV, 560 amperes continuous. The phase-trip pickup current is 280 amperes (140-ampere coil), and the operating sequence is one fast (A) and three slow (C) operations. The reclosing time interval between the fast operation and the first delayed operation is 0.5 second (instantaneous). Between the delayed operations, the reclosing time interval is 5 seconds.

COMPLETING THE EXERCISE USING COORDINAIDE

To complete the coordination exercise, launch Coordinaide by clicking the appropriate link on the page of S&C's website you're visiting... A Coordinaide link is featured on the home page.

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Fault Detection

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ulatory commission complaints are two other tools that can be used; however, those are worst-case situations utility companies attempt to avoid. Ideally, reliability indices are tracked by the utilities that remain proactive when it comes to operation and maintenance of their systems and therefore reliability.

While performance indices generally do not track momentary outages specifically, most utility customers will not distinguish between long or short outages.

In fact, many utilities report that their customers tend to file more complaints regarding frequent, short-duration power outages than they do longer-term, storm-related outages.

Momentary outages that happen repeatedly in a day are even more likely to draw undesirable customer attention due in part to the inconvenience of rebooting computer systems and resetting digital clocks. An inexpensive apparatus that can be deployed to help isolate the cause and timing of momentary faults is invaluable in maintaining customer satisfaction.

In order to manage and improve system performance, utilities use a variety of tools. Some will initiate specific projects intended to improve reliability on their poorest-performing circuits. These reliability projects can include, but are not limited to, tree trimming, tap-fuse installation, fault-indicator installation, coordination studies, circuit tie lines, replacement of bare conductor with insulated cable, relays, substation monitoring equipment, or installation of additional switchgear and controls.

These options range in cost from the less-expensive devices such as additional cutouts, tap fuses and faulted circuit indicators to the more expensive insulated cable and switchgear installation.

Taking this a step further, some utilities are extending the capabilities of their existing Advanced Metering Infrastructure (AMI) to help them identify and locate outages on their system.

This technology provides system operators with the ability to actively poll meters at specific locations as opposed to contacting customers by phone and asking them if they have service or not.

Using this technology can be valuable, but at the same time, it does present some limitations.

If a large area is affected by an outage, none of the metering will report back. The data is too generalized to be of value, and inner-outages can be missed. The time taken to perform the polling is also a significant disadvantage.

Following each restoration effort, the metering devices must again be polled to verify that the outage is fully restored. As a result, utilities have expressed a need for a device that will monitor the system, detect fault events, and report a fault or an outage as well as execute power restoration in real time.

The OutageAdvisor system provides visual alerts about real-time grid conditions.

THE SOLUTION

The OutageAdvisor Fault Detection and Location Solution is designed to uti-

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Additional links are found under the drop-down menu labeled "Support" and also on applicable product pages; e.g., S&C Type SMD Power Fuses. These tab-style links are on the left-hand side of the page, immediately below the "For More Information" label and above the "TCCs for [product]" tab.

After clicking on one of the links, you'll be directed to Coordinaide's opening page. It provides a brief description of the applications Coordinaide is designed to handle. When you launch the program, you'll be directed to a second page containing a brief "Conditions of Use" disclaimer, followed by a short note detailing minimum web browser requirements and a link to a "Users Guide."

One final click launches the program and takes you to the "General Information" page. Please follow these directions to select the primary-side fuse, the transformer, and the load-side recloser.

Step 1 — Enter General Information

• Project Name: Fuse-Recloser Coordination Exercise
• Date: [provided by Coordinaide]
• By: Optional

Step 2 — Enter System Information and Select Devices

• Three-Phase Voltage, kV: 115
• Available Fault Current, Amperes RMS Symmetrical: 10000
• Device #1 — Power Fuse
• Device #2 — Transformer (Damage Curve)
• Device #3 — Recloser

Click "Continue" after entering system information and selecting the devices. You'll be directed to the first "device" page.

Step 3 — Select and Enter Device Parameters

Device #1 — Transformer-Primary Fuse (Select Parameters)

• Manufacturer: S&C
• Type: SMD-2B
• Speed: Standard
• Voltage Range, kV: 115-138
• Ampere Rating: 65E

Click "Continue" after selecting the parameters for Device #1. The time-current characteristic curve for Device #1 will be displayed.

Device #2 — Transformer (Select Parameters)

• Three-Phase Primary Voltage, kV: 115 [Provided by Coordinaide]
• Three-Phase Secondary Voltage, kV: 13.2
• Three-Phase Rating, kVA: 7500
• Impedance, %: 7.5
• Fault Current, Amperes RMS Symmetrical: 10000 [Provided by Coordinaide]
• Display Magnetizing Inrush Points? _ Yes _ No (default)
• Connection: Delta Grounded-Wye

Click "Continue" after selecting the parameters for Device #2. The time-current characteristic curve for Device #2 will be displayed.

Device #3 — Feeder Recloser (Select Parameters)

• Coordinates With: _ Source-Side Device _ Load-Side Device See Note 1
• Coordination Method: _ Cooling Factor _ Conservative (default) See Note 2
• Manufacturer: Cooper (McGraw): Hydraulic
• Type: W
• kV Range, kV: 14.4 [Provided by Coordinaide]
• Phase-Trip Operating Sequence: 1 Fast / 3 Slow
• Fast Curve: "A"
• Slow Curve: "C"
• Coil Rating, Amperes: 140
• Ground-Trip Operating Sequence: Skip for this example

Note 1: Since the recloser is on the load side of the primary-side fuse, select "Coordinates with Source-Side Device (default in this example)."

Note 2: Select "Conservative Method" to disregard the effects of cooling of the primary-side fuse during reclosing time intervals (contacts open) of the recloser. You are encouraged to repeat this example using the more precise cooling-factor method, and then compare the results.

Click "Continue" after selecting the parameters for Device #3. The time-current characteristic curve for Device #3 will be displayed.

Step 4 — Go to "Results" Page

Click on the tab at the top labeled "Results." You'll be directed to a log-log grid with

TCC curves of the devices you've selected.

If desired, you can change the current scale of the grid from the default, 5 to 100,000 amperes, to 0.5 to 10,000 amperes. You can also eliminate the hash-fill applied to the TCC curves, to make the plot more readable. And you can zoom in on a particular section of the grid by entering the upper and lower current and time values in the appropriate cells.

To see a full-size TCC plot or full-size summary information, click on "Printer Friendly Graph" or "Printer Friendly Summary," as applicable.

Now let's review the TCC plot of the coordination example under consideration.

Device #1, the 65E-ampere Standard Speed primary-side power fuse, is plotted in red.

Device #2, the transformer damage curve, is plotted in black. And Device #3, the loadside recloser, is plotted in orange. The two thicker orange curves are the recloser fast curve (A) and slow curve (C), respectively, based on TCC data published by the recloser manufacturer. The thin orange curve is the maximum-equivalent lockout curve of the recloser, reflecting positive tolerances.

The 65E-ampere Standard Speed power fuse provided excellent protection for the transformer as evidenced by the fact the total-clearing curve of the fuse crosses the transformer damage curve at current levels less than the maximum values obtained for any type of fault. This fuse has a published peak-load capability of 107 amperes, which means that the transformer can be loaded to nearly 280% of nameplate — well in excess of the desired OA/FA rating (125% of nameplate).

Unfortunately, the primary-side fuse does not coordinate with the maximum-equivalent lockout curve of the recloser, since the minimum-melting time of the fuse at 478 amperes (0.42 second) is less than the maximum- equivalent lockout curve of the recloser at this current level (0.69 second). Note that the secondary-side recloser curves have been shifted to the

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Fault Detection

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lize both existing fault indicator technology and commercially proven communication technology to quickly and accurately locate faulted sections of a utility's distribution system. The OutageAdvisor Solution provides utilities with the ability to achieve greater reliability and reduce O&M expense. This simple, yet sophisticated, solution is designed to quickly and accurately indicate both permanent and momentary faults and find their location as well as shorten response time and improve reliability indices.

The benefits of this device include detection and location of permanent faults, recloser monitoring, and vegetation management assistance.

APPARATUS SENSORS

The OutageAdvisor sensor is based on Cooper Power Systems Pathfinder Current-Resetting Faulted Circuit Indicator (SCVT).

This easily installed device contains field-proven technology with high reliability. In addition to the functionality of the SCVT, this device will differentiate between momentary and permanent faults and indicate restoration of system power. It will also provide data, including battery status, system power status, average load current, and the location of the device, through an existing wireless communication network. Periodic health transmissions are also sent to provide updated information and indication of consistent communications. These features are in addition to the ease of application and installation utilities have come to trust with the Cooper Power Systems line of S.T.A.R. Faulted Circuit Indicators.

COMMUNICATION INTEGRATION

This solution is designed to be available with minimal investment in a communication network. The OutageAdvisor Fault Detection and Location Solution supports wireless technologies using either a national cellular network or RF radio technologies (licensed and unlicensed bandwidth options). This allows for a more flexible solution that requires minimal infrastructure investment. Cooper Power Systems will work with the utility to determine their communication capabilities and requirements. Services can include communication survey, drive-test propagation study, installation and deployment support, post-sale technical support, and optimization.

ENTERPRISE SOFTWARE INTEGRATION

As part of the overall GridAdvisor Solution, Cooper Power Systems will offer a software package called the GridAdvisor Exchange (GAX). This software will fully integrate the smart sensor data into an existing outage management system (OMS) using common communication protocols such as DNP 3.0, ICCP (Inter-Control Center Communications Protocol) or MultiSpeak software specification.

By residing on the utility-owned server, the exchange resides behind the existing secure firewall managed by the internal IT group. This will minimize administrative setup. The solution is also designed to run seamlessly with other utility control center applications. The GridAdvisor Exchange is engineered to integrate and transfer OutageAdvisor sensor information with existing systems. This minimizes the operator learn-

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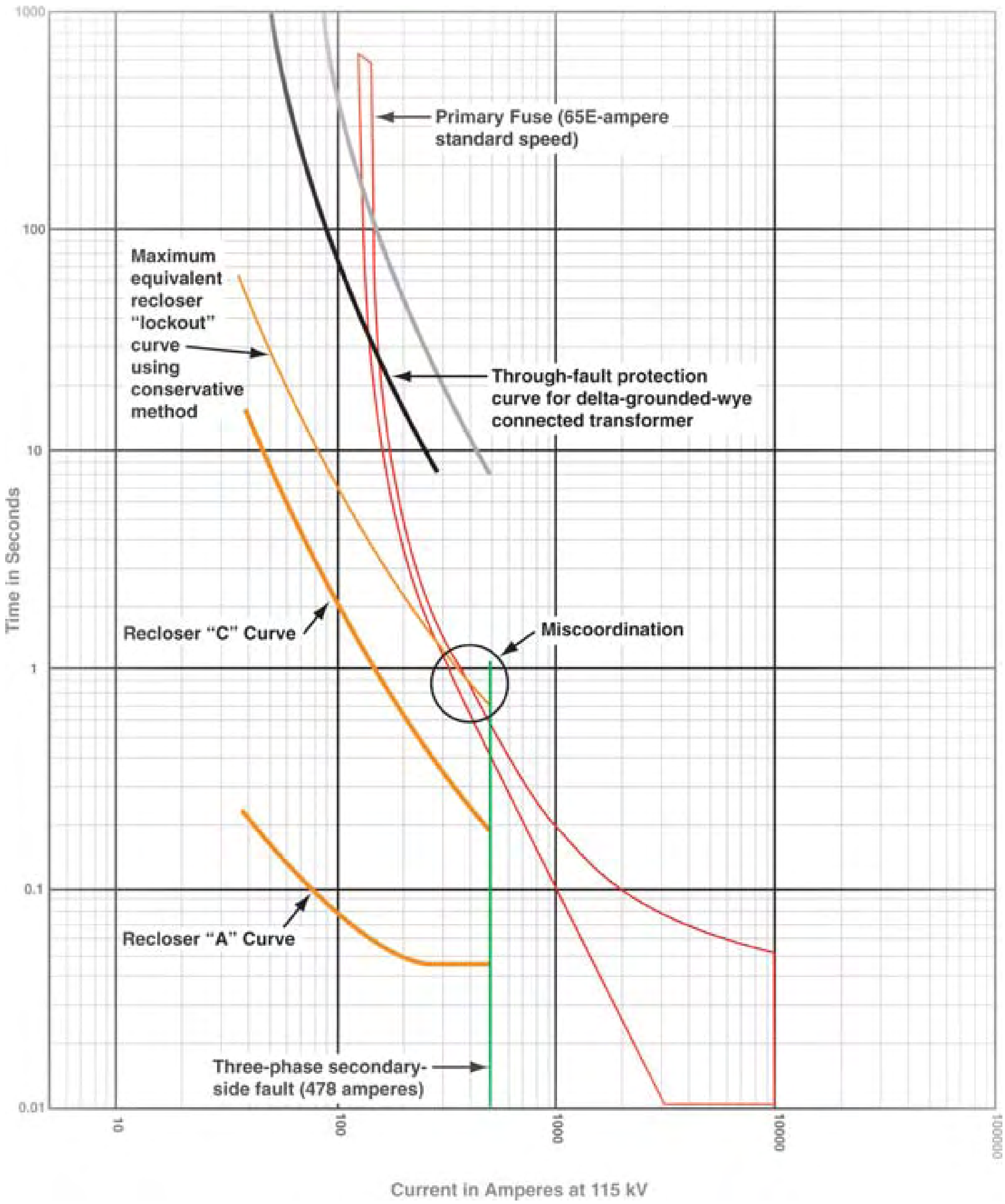
Feeder Reclosers

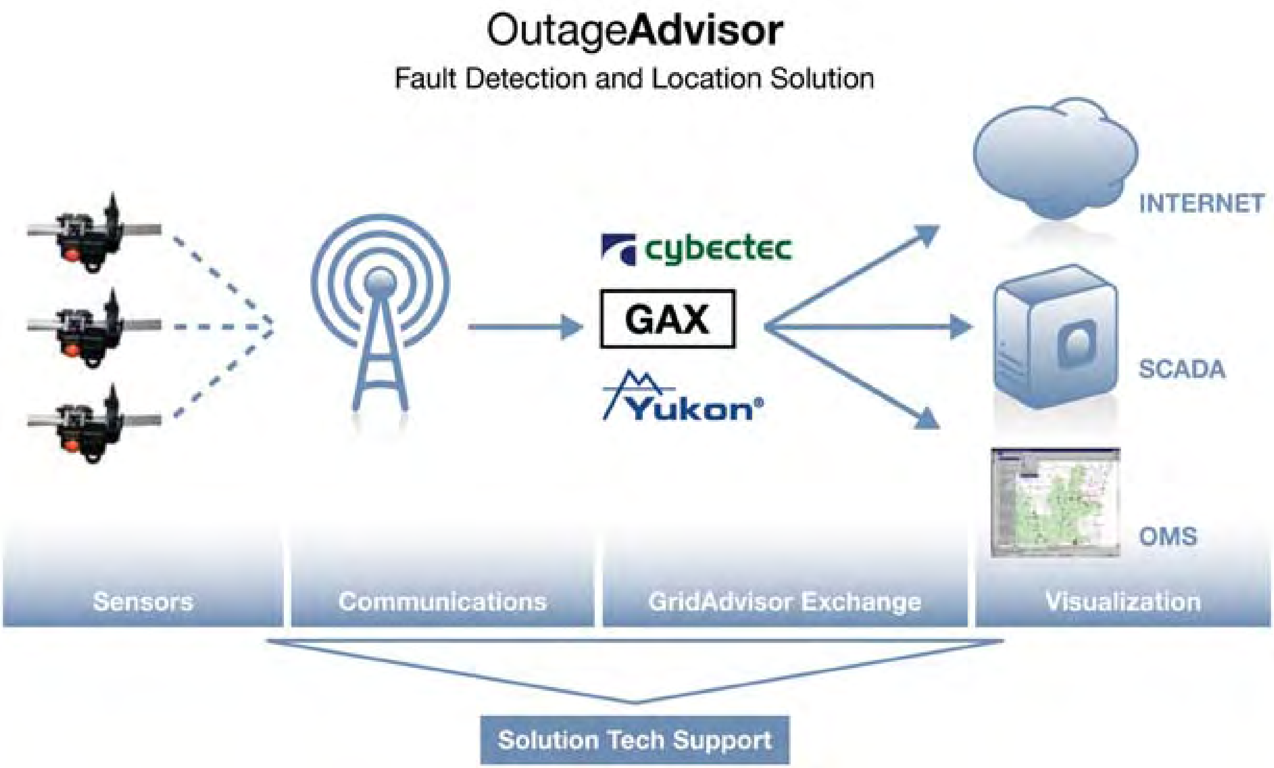
Continued from Page 56

right, by 15% in terms of current, to account for the primary-side to secondary-side current imbalance that would exist were a phase-to-phase ungrounded secondary-side fault to occur.

When faced with this situation, the natural reaction is to select the next-larger-ampererated primary-side power fuse, a fuse with a slower time-current characteristic, or perhaps both... until coordination is achieved. While this solution may result in complete coordination between the fuse and the recloser, it does so at the expense of transformer protection — not the optimal result. Before selecting a larger fuse, or one with a slower time-current characteristic, repeat this exercise using the more precise cooling-factor method.

You may find that the primary-side fuse initially selected provides complete coordination after all!





Fault Detection

Continued from Page 57

ing curve, allowing users to continue to work with a system they've come to know and trust. This system simply adds more data and functionality.

Other features include the ability for the data to be scanned by a utility's Supervisory Control and Data Acquisition (SCADA) system and a Human-Machine Interface (HMI) where an operator can view and manipulate administrative data.

Also available is a web-hosted solution that operates on the Cannon Yukon software platform from Cooper Power Systems. The advantage of this option is that the Yukon platform already has some of the functionality of an outage management system — if the utility is not currently running one — and the system is hosted by Cooper Power Systems. This provides an opportunity to pilot the OutageAdvisor solution before a full deployment takes place.

DISTRIBUTION AUTOMATION: THE FUTURE OF THE SMART SENSOR

By deploying the OutageAdvisor Fault Detection and Location Solution, a utility takes an initial step towards an automated distribution system. This low-cost, high-value proposition can lead a utility to a more automated and reliable electric system.

Cooper Power Systems is actively working towards being the manufacturer of choice for utilities heading towards a fully automated distribution system.

Look forward to more devices from the GridAdvisor Solution suite of products — including a capacitor bank fuse-open detector, switch position indicator, and power theft monitor device, which will be available in the very near future.

COLLECTING DATA ACCURATELY WITH HYDRO ONE

By Steve Webb

Data collection presents a bigger challenge for some workforces than others. At Hydro One Inc., one of the largest electric utility companies in North America, field workers are responsible for inspecting and maintaining 47,000 transmission towers and 1.6 million utility poles across the province of Ontario.

Many of Hydro One's technicians drive in vans and line trucks to conduct inspections in urban areas such as Toronto and Ottawa. Other workers rely on less traditional types of transportation. In the winter, technicians ride snowmobiles to access remote utility lines and poles. In the summer, they travel by boat to cottages and other locations to conduct planning work and inspect transmission equipment. Other technicians ride in helicopters to inspect 200-foot transmission towers.

The paper-based system Hydro One formerly used to update its asset database created a variety of problems. The inspection forms Hydro One's technicians filled out by hand were submitted to data entry employees who typed the information into PCs to update the database.

Field workers tend not to have the most legible handwriting, particularly when collecting data during a bumpy helicopter ride or in subzero temperatures. As a result, clerks sometimes entered incorrect information. In addition, paper forms sometimes got wet or muddy, making it even more difficult for data entry clerks to decipher information. There was also the possibility that technicians would lose the paper forms. The bottom line is Hydro One's Investment Planning Division, which makes decisions on maintenance upgrades and other capital investments, could not depend on the reliability of inputted data.

"Investment planners make life cycle decisions based on these inspections. These assessments drive multimillion dollar decisions," says John Dobie, senior supervisor of technical services at Hydro One Networks Inc., the division of Hydro One responsible for maintaining and operating the utility company's transmission and distribution systems.

"If there's doubt about the data, that's really an error. If people aren't confident they can use the data, then that's an error."

In an effort to improve accuracy, increase productivity, and cut costs, Hydro One decided to look into automating the data collection process. The company initially equipped some of its field workers with hand-held computers. However, charts and various assessment forms did not fit on the small screens. That meant workers had to use a series of dropdown menus to input data. "Because of the small form factor, we couldn't do the things we needed to be fully successful," says Dobie. "If a worker missed even one dropdown screen, we had incomplete data."

Hydro One wanted a computer with a larger screen size and greater storage capacity. The ability to withstand subzero temperatures, dust, vibration, contact with water, and drops to concrete was also essential. "When you look at the distances we travel, we can't afford to have equipment fail and have workers repeat their work," says Raymond Gee, manager of work management and deployment at Hydro One Networks. "The ruggedness was important because employees don't see these devices as computers; they see them as a tool. They're not going to treat them with kid gloves."

TABLETS BOOST DATABASE ACCURACY

Two years ago, Hydro One tested tablets from Xplore Technologies Corp. and one other computer company and determined that Xplore's computers could best withstand extreme field conditions. Hydro One has equipped 490 of its employees – roughly half of its field technicians – with iX104 tablet computers. Since the computers have 40 GB of hard drive space, Hydro One is able to populate transmission tower locations on each device. This enables field technicians to update data on any structure or piece of equipment by selecting menu choices with a digitizer pen. The system runs on the FORMEngine Mobility Suite provided by FORMotion Systems. The GPS (global positioning system) solution Hydro One has developed for the GPS-equipped tablets enables technicians to pinpoint the location of the tower, utility pole, and other transmission equipment they are assigned to inspect.

When employees download data via an Ethernet LAN (local area network) connection, the company's asset database is automatically updated. "We're using a LAN at every one of our operation centers. Some field workers download data once a day, while others connect once a week," says Dobie. "Our workforce is mobile and we work around the whole province.

That's another reason we needed storage capacity of a tablet computer versus a handheld. Workers can do more than one day of data collection. When they're in the northern part of the province, they might be away from a LAN connection for a week."

The accuracy of data collected on the tablets is approaching 100%. In applications such as meter data collection, roughly 30% of the manually completed forms contained at least one error. "The increase in accuracy is the biggest benefit, along with the fact that our database will be perpetually self-updating," says Dobie. "This is empowering our executives to make good decisions."

HELICOPTER TECHNICIANS DOUBLE PRODUCTIVITY WITH TABLETS

Technicians who ride in helicopters to inspect transmission towers have been able to streamline their data collection procedures by using the Xplore tablets. Previously, two technicians in each helicopter had to sort through several paper forms to write down assessment data. Now, one technician dictates information about the insulators, vibration dampers, wires, and other sections of the tower, and a second technician uses a digitizer pen to select menu options on the screen. Inspections that formerly took about 2 minutes per tower have resulted in inspectors being able to more than double the number of towers they inspect each day. "On a good day before, helicopters would cover 40 kilometers (25 miles) of towers. On most days today, we do more than 100 kilometers (62 miles)," says Dobie. "We have improved the speed and the accuracy of the inspections at the same time."

Heightened employee accountability has been one important byproduct of the new system. Previously, if incorrect data was entered into the database, there were doubts whether the technician or the data entry clerk was responsible for the mistake. "The person who inputs the inspection on the tablet is accountable for that information," says Dobie. "There is no more passing the buck because someone else manually input the data."

USE A LAN TO AUTOMATE ORDERS

Hydro One has begun implementing another improvement to its data collection system– automated work orders.

The company's meter technicians are testing the system, and Hydro One eventually plans to roll out the automated system across all field applications. Instead of receiving work orders on paper sheets, 25 of the company's meter technicians now plug their tablets into an Ethernet LAN outlet to download their work orders. The application also includes a workflow system. When a technician completes a work order, data on the job is automatically transmitted to a supervisor's tablet. If the supervisor accepts the work order, the company's database is automatically updated.

However, if the supervisor determines the job hasn't been completed correctly or that the report requires additional data, the work order is routed back to the technician.

With this automated work order system, Hydro One hopes to create more efficient work schedules to drive worker productivity.

In another tablet application, Hydro One is automating the collection of data from meters. When an optical probe attached to the tablet is connected to a meter, customized software automatically downloads the meter number, the brand of the meter, and the multiplier used to determine electricity usage. "The technician uses a digitizer pen to select from a prepopulated list," says Dobie. "Before, about 30% of metering forms were completed incorrectly. Now we're approaching 100% accuracy."

GERATER RAM ALLOWS HYDRO ONE TO MOVE MORE WORK TO THE FIELD

Due to the improved accuracy and productivity Hydro One is achieving with the tablets, the company has placed an order for 400 more of the computers. The iX104C2 tablets on order contain 1 GB of RAM (random access memory) vs. 512 MB of RAM in the current tablets Hydro One is using. The faster processing speed of the new tablets enable technicians to use programs such as ArcFM, a program used to manage and map assets. "As you start moving more design and analysis work to the field, you need more storage capacity," says Dobie. "Before, employees did the work on their desktop PCs in the office."

As Hydro One equips more of its field workers with tablets, technicians sometimes have to be reminded that they are meant to view the outdoors as their workplace.

"We've been trying to show employees that the right way to do their work is out in the field," says Gee.

"Some employees want to turn the cab of their truck into an office. My view is that we don't need to spend $500 to outfit the cab of the truck and turn it into an office.

"We still have that office mentality that we need to break." Since the tablets automatically update the company's database, Hydro One is achieving labor savings by eliminating temporary data entry positions. Due to the increased efficiency in the field, Hydro One also expects to be able to achieve further cost savings by reducing the number of field technicians through attrition. For instance, the company eventually plans to reduce the number of technicians used in the helicopter inspections from 2 to 1. The company has estimated that it will achieve a return on investment in about 1.4 years due to labor savings, improved accuracy, and the durability of the tablet computers.

> "Some employees want to turn the cab of their truck into an office. My view is that we don't need to spend $500 to outfit the cab of the truck and turn it into an office. We still have that office mentality that we need to break."

Communication With Vendor Produces Glare-Resistant Screen

When Hydro One initially deployed 100 iX104 Xplore tablets in the field, the computers performed according to expectations.

But technicians did report one problem: glare from the sun made it difficult to read data on the screens. "I kept challenging Xplore about the glare on the screens," says John Dobie, senior supervisor of technical services for Hydro One Networks Inc.

His persistence paid off. Largely due to the feedback from Hydro One, Xplore developed a screen with an antireflective coating that reduces glare from sunshine. This screen also features greater impact resistance. "We showed them prototypes of the technology and their feedback was very important to us," says Patrick Gray, director of product marketing at Xplore.

The improved screen design encouraged Hydro One to purchase an additional 390 iX104 tablets, and the company has 400 of the newer model iX104C2 computers on order.

FIELD TESTS HELP HYDRO ONE SELECT PRODUCT

Before purchasing its first tablet computer, Hydro One conducted research to ensure the product it selected would be rugged enough for employees in the field. For Hydro One, that process involved much more than studying specification sheets. After Hydro One narrowed its choice to different tablet brands, it asked each computer manufacturer to provide two complimentary test models.

Xplore Technology Corp.'s iX104 tablets are engineered to meet U.S. Military Standards (MIL-STD 810F) for environmental extremes, but Hydro One wanted to see for itself if the tablets would lose data if subjected to rough treatment. Since Hydro One uses barges to lay cable in the summer and technicians use boats to get to some work sites, the company wanted to see if the devices would still work if submerged in water. The company placed the Xplore tablets under water for 10 minutes with applications running. The applications continued to work while submerged, as well as after the devices were removed from the water.

Hydro One also conducted a series of drop tests. Testers tossed the Xplore tablets onto cobblestone pavement more than 20 times. "Our hope was that the application wouldn't stop running or lose data. In the field, technicians want to be able to pick up the tablet and continue with their work. They don't want to reboot or worry about losing data," says Dobie.

The applications on the Xplore tablets continued running after the drops and no data was lost. The other tablet computer did not perform as well in Hydro One's tests, but the company purchased 125 of the computers for less rugged applications.

EXPANDING PUMPED HYDROELECTRIC STORAGE

By Harry Valentine

Advances that are occurring in energy conversion technologies and in the marine shipping industry could strengthen the case for high-capacity pumped hydraulic energy storage at Niagara Falls.

At the present time, the United States leads the world in the number of pumped hydroelectric installations of over 1,000 megawatts, followed closely by Japan. America's largest such installation at Bath County, Virginia transfers water over a vertical height of 1,262 feet and is rated at 2,100 MW. The Ludington installation on Lake Huron in Mason County, Michigan uses a vertical height of 363 feet and is rated at 1,872 MW.

The largest installation in New York State that is located 30 miles southwest of Albany involves a vertical height of 1,200-feet and is rated at 1,200 MW. By comparison the pumped hydroelectric installations at Niagara Falls are relatively small with the Lewiston pumping station in New York being rated at 240 MW and the Adam Beck pumping station in Ontario being rated at 174 MW.

Lake Erie covers an area of 9,900 square miles and its water level is 326 feet above the adjacent Lake Ontario that covers an area of 7,300 square miles. Some 185,000 cubic feet of water per second flows through the Niagara River from Lake Erie into Lake Ontario.

The water flow rate over Niagara Falls is controlled so as to assure the economic viability of the tourist trade at Niagara Falls, to maintain hydroelectric power generation capacity downstream at the Moses-Saunders and Cedar Rapids power dams on the St Lawrence River where the marine shipping depends on sufficiently deep water levels. The hydroelectric power stations at Niagara are rated at 2,500 MW for New York and 1,600 MW for Ontario where generation capacity is being expanded by boring a new tunnel.

It may be quite possible to modify the exit of the new Beck tunnel to allow for the installation reversible turbines. At different times, such turbines drive electrical generation equipment and also pump water over greater vertical height (363 feet) than between Lakes Ontario and Erie (325 feet).

The tunnel boring machines that can produce passages of up to 50-feet in diameter through the solid rock at Niagara could be used to bore many more parallel tunnels in that vicinity over a period of several decades. Such action would gradually increase pumped hydraulic capacity and related power generation capacity. A slightly lower water volume flow rate that flows into Lake Erie could flow over Niagara Falls during the day to preserve the tourist trade and be reduced overnight.

Water levels in Lake Ontario would drop by 1.1 inches if 800,000 cubic feet of water per second were pumped uphill through multiple tunnels into Lake Erie between midnight and 6 a.m. Lake Erie's water levels would rise by 0.81 inches during that period.

The sheer capacity of the 2 lakes can allow for 18 trillion cubic feet of water to be pumped to the higher elevation with minimal change in the height of either lake. That water would return to Lake Ontario during the same day during peak generating periods when up to 14,000 MW may be possible for up to 8 hours duration, or up to 11,000 MW for up to 10 hours. That power would be shared between New York and Ontario. This cyclic movement of water at Niagara should barely register across the large expanse of Lake Ontario in the shipping channels of the St Lawrence River or at the Moses-Saunders hydroelectric power station.

POSSIBLE SOURCES OF ENERGY TO PLACE INTO STORAGE:

New York State is projected to have a possible shortfall of electrical power within the next two decades during which time Ontario will rebuild much of their generation capacity. The Manley report recommended using proven generation technology at the time when it was written. It suggested that wind turbines of 200 feet in diameter with the hubs at 80 metres or 262 feet above ground could

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SOLVING THE LIGHTNING PROBLEM

By Del Williams

Engineers at Lightning Eliminators & Consultants have deployed an integrated lightning prevention system for Browns Ferry Nuclear plant which included DAS strike prevention technology.

Lightning solution keeps the Browns Ferry Nuclear Plant’s off-gas stack strike free, reducing lightning strikes by 80% within a 500-meter radius.

Like all power generation plants, the Browns Ferry Nuclear (BFN) Plant, in northern Alabama, faces many challenges to meet the power demands of a growing and urbanizing population. With Alabama’s frequent and intense storms, the challenges posed by lightning had proven to be especially trying due to repeated strikes to the off-gas stack.

Today, BFN prides itself on safe, efficient, and affordable electric power generation for its customers. As the first nuclear power plant of the Tennessee Valley Authority (TVA), the nation’s largest public power company, BFN was the first nuclear plant in the world to generate more than 1 billion watts of power and was the world’s largest when it began operation in 1974. In 2006 BFN helped TVA achieve 99.999 percent operational reliability for the fifth year in a row. But a decade ago, lightning strikes to BFN’s off-gas stack were hampering reliability.

“The off-gas stack was originally protected by Franklin rods, but equipment on the stack and around its base (was) routinely damaged during lightning storms,” says Rick Brehm, a TVA manager with oversight of electromagnetic interference and instrumentation, and control systems. “Lightning strikes to the stack were observed.”

The damage from strikes required considerable equipment replacement and repair. While the automated monitoring equipment was offline, extended periods of human monitoring were necessary, which increased the workload and expense.

To improve reliability and reduce downtime, BFN turned to Lightning Eliminators & Consultants, Inc. (LEC), which specializes in lightning prevention technology, a relatively new innovation in the lightning protection industry. BFN’s move is not uncommon; a growing number of respected power generating utilities have successfully reduced costs by choosing engineered lightning prevention systems to avoid storm-related damage.

Unlike antiquated lightning rods, which collect and direct lightning at a site, charge transfer technology prevents direct strikes by reducing the local electrical field to below lightning-collection potential. LEC’s charge transfer device, the Dissipation Array System or DAS, has been installed at industrial facilities around the world and is custom-engineered to interface with almost any structure.

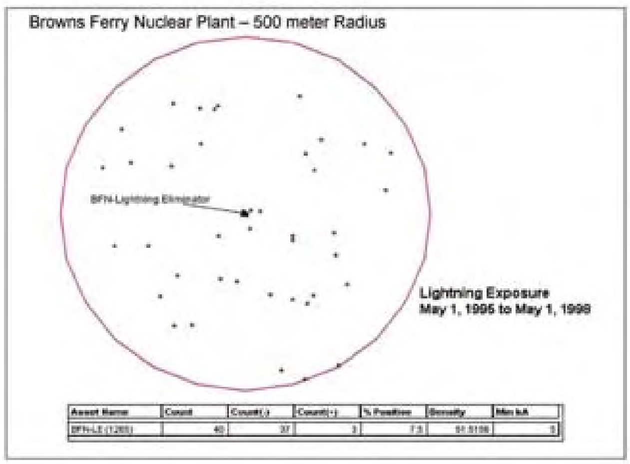

Figure 1 is BFN – 500 meter radius lightning exposure May 1, 1995 to May 1, 1998, Lightning Eliminators & Consultants.

To design a comprehensive protection scheme, LEC took into account factors such as the off-gas stack’s location, size, shape, equipment, geography, and exposure to lightning activity. They then engineered and deployed an integrated lightning prevention system for BFN, which included DAS strike prevention. Spline Ball Terminals (SBTs), a form of hybrid preventer/collector, were used to augment the protection for the sensitive equipment around the off-gas stack's landings.

"The result has been no known lightning strikes to the off-gas stack in almost ten years," says Brehm. "Instead of using our resources to repair broken equipment and pay emergency overtime, we're preventing the problem in the first place."

As part of an internal review process, BFN consulted a database of lightning activity to determine the number and location of lightning strikes around the off-gas stack in the three years before and after DAS implementation. They compared the number and location of lightning strikes within 500-meter, 3, 6, and 10-mile radius circles of the off-gas stack for these periods. (See Figures 1 and 2)

"Following DAS implementation, we found an 80% reduction in lightning strikes within 500-meters of the off-gas stack," explains Brehm. "The weighted data for strikes in the wider areas showed no change of statistical significance, though lightning frequency increased by almost 63% in a 10-mile radius around the stack in the three years after DAS implementation. The data shows us the DAS system works. It's undoubtedly saved us from tons of potential lightning strikes since it's been implemented."

In another test of DAS's effectiveness, BFN recently monitored the voltage drop on a ground cable downcomer from the DAS array on the off-gas stack down to the ground via a voltage sensor. The monitoring lasted about six months, during which time they detected no lightning strikes and current flow remained in the milli-amp range.

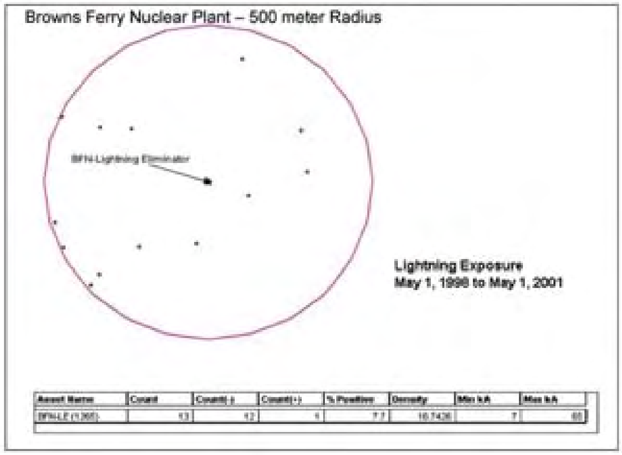

Figure 2 is BFN – 500 meter radius lightning exposure May 1, 1998 to May 1, 2001, Lightning Eliminators & Consultants.

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Pumped Storage

Continued from page 63

produce up to 5 MW output each and account for up to 15% of Ontario's future generation capacity. A more recent design of vertical-axis wind turbine from the UK extends to a height of 470 feet to 490 feet above ground and is rated up to 9 MW output.

An advanced design of vertical-axis wind turbine from China can ride on magnetic levitation and generate over 50 MW in a wind speed of 30 miles per hour. Research, development and initial testing have already been undertaken on airborne wind turbines that could generate up to 100 MW of power from high-altitude winds. There are numerous locations across eastern Canada as well as the northeastern and south-central U.S. where several designs of wind turbines could generate power at different elevations and from where off-peak power may be transferred into storage including at Niagara.

There is renewed interest in the United States and in Ontario to increase nuclear-electric generation capacity. Nuclear and other thermal power plants achieve optimal efficiency and cost effectiveness when thermal components operate at constant temperature and pressure. They would run at constant output and require access to high-volume energy storage capacity. The presence of massive storage capacity at Niagara could prolong the service lives of many thermal power stations. It would also allow the purchase of massive amounts of off-peak power at low cost that would be re-sold at a higher price during the peak periods.

Power could be generated from ocean tides at regular intervals including outside of the periods of peak market demand. Variable amounts of power could be generated intermittently from ocean waves. Having access to high-capacity energy storage could enhance the economic case of ocean tidal and ocean wave energy conversion. A portion of the off-peak oceanic electric power that may be generated along America's Atlantic coastline and also along Hudson Strait could be transferred into storage at Niagara in the distant future.

> Pumped hydraulic storage could offer major long-term economic benefits to both New York State and to Ontario.

A group of American researchers recently examined the future possibility of generating electricity from concentrated solar photovoltaic and concentrated solar thermal technologies in the desert area of the southwestern U.S. That group proposed to store energy using compressed air in emptied subterranean salt domes. Solar-electric power from the southern U.S. could be carried along UHV-DC power lines into storage at Niagara at a future time. Mega-hydraulic storage would exceed the capacity, efficiency and operating cost of compressed air storage technology. The evolution and development of cost-competitive renewable energy technologies strengthens the case for mega-capacity pumped hydraulic storage between New York and Ontario.

MARINE OPERATIONS:

There are long-term plans to widen and deepen the shipping channel to allow longer and wider ships that have a keel depth of 45 feet to sail into Lake Ontario and possibly into Lake Erie. Wider and deeper channels will increase water flow rate through the St. Lawrence River and even through the locks that are located adjacent to the power dams. Side reservoirs and pumping equipment would have to be installed at several locks so as to maintain a constant water flow rate through the shipping channels.

Allowing ships with a keel of 45 feet in depth into Lake Erie would require that water levels be maintained at a higher level in that lake as a way of maintaining water depth in the Detroit River and St Clair River. It would also require a massive rebuilding of the locks and shipping channel between Lakes Ontario and Erie. Pumped hydraulic storage could be installed at the larger locks in the future to save water and assist the energy industry while ships are transferred in between elevations during the overnight hours.

CONCLUSIONS:

Pumped hydraulic storage could offer major long-term economic benefits to both New York State and to Ontario. Ontario could install reversible turbines in a modified exit of the new tunnel that is being constructed at Niagara so as to economize on water. New York State and Ontario would both realize economic benefits in power generation after additional hydraulic tunnels are drilled on both sides of the border at Niagara and reversible turbines installed.

The International Joint Commission and the International St Lawrence Board of Control are the tribunals that will ultimately decide as to whether or not to allow for the installation of mega-hydraulic storage technology between the upper and lower sections of the Niagara River.

Lightning Protection

Continued from Page 65

"We saw milli-amps of current flowing up and down the downcomer," says Brehm. "This indicated that DAS was making the stack a less attractive strike target. The data showed DAS functioning as intended."

"It's preventing strikes to the protected area and proving to be an effective long-term solution." Because of the DAS prevention system's success in protecting the off-gas stack from lightning strikes, BFN is looking into extending the area of protection to a nearby intake pumping station which recently sustained motor damage due to lightning.

LEC has used Dissipation Array protection systems to provide engineered areas of protection in a variety of public utilities and facilities. DAS systems provide complete lightning protection to an extensive list of customers and facility types, including the TVA, DOE, Calpine, Florida Power & Light, Michigan Public Power Agency, Canada Atomic Energy Commission, and Korean Electric Power, as well as many Fortune 500 firms such as ExxonMobil, ChevronTexaco, PPG Chemical, Union Camp, and Federal Express.

Since 1971, DAS protection has accumulated over 40,000 system-years of history with 99.85% no-strike performance. It has been installed at thousands of locations in 55 countries worldwide, including facilities as large as three square kilometers and structures as high as 1,700 ft.

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