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June/July 2006
Volume 18, No. 5

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HUBBELL POWER SYSTEMS

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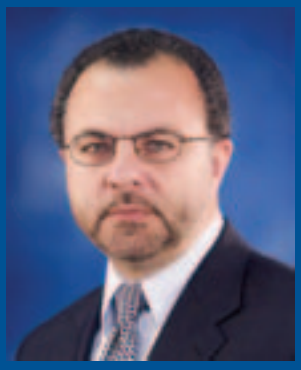

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GLOBAL WARMING PRESENTS A DOUBLE THREAT TO HYDRO GENERATION

By Don Horne

The first, best and cleanest source of electricity – hydro – is under the gun from Mother Nature, courtesy of global warming.

Hotter, more humid summers that stretch deeper into the autumn months and are welcomed by sun worshippers in late May and early June are not only straining electricity grids to keep air conditioners humming, but are drying up the very source of power needed to create that electricity – water.

A report on the climate impacts on Washington State's hydropower, water supply, forests, fish and agriculture, casts a concerned eye at where global warming is taking these valued resources.

"Increasing temperatures, decreases in snowpack, and shifts in the amount and timing of streamflow will likely (increase) summer demands (and) are likely to increase overall while summer generation is likely to decrease."

Further on, the report states that, "Despite the uncertainty of long-term projections of climate conditions, all scenarios call for a warmer future. For impacts that are strongly temperature dependent, the severity of pre-2050 impacts could be augmented by additional temperature change."

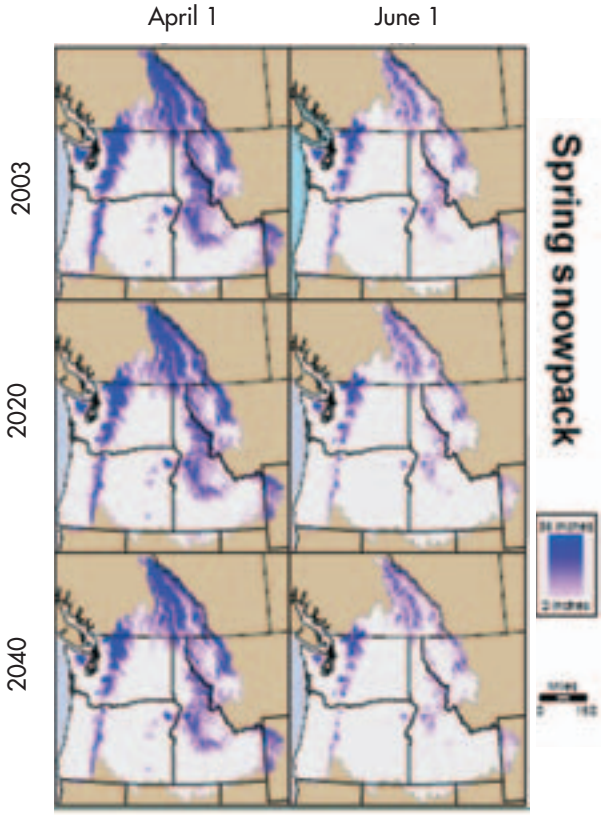
Such change would include global warming that could:

• Exacerbate declines in snowpack and shift the timing of peak streamflow for snowmelt dominant and transient watersheds even earlier in the year. Some transient watersheds may no longer be fed by snow and could become rain dominant.

• Make it even more difficult to simultaneously generate hydroelectric power and reliably fulfill in-stream flow targets, lake levels sufficient for recreation, and water supplied for irrigation.

• Summer electricity demand could continue to increase while generation could decline, leading to shortfalls.

Not terribly serious when you look at the northwest, but when you consider the impact it will have on the American southwest, already starved for electrical power and clean water, the repercussions of global warming are massive.



The continued influx of people who are now calling the southwest home has placed an incredible demand on electricity grids in such sun states as Arizona and New Mexico. Rising temperatures only exacerbate the problem (Look no further at the current generation woes of the East African nation of Uganda, that is currently in the throes of a drought and is losing anywhere from 80 to 90 MW of generation).

Turning back to the Pacific Northwest, declines in snowpack levels have been occurring since 1945. Snowpack is essential to maintaining reservoirs during the spring runoff, and although warmer temperatures would mean greater hydro generation during the winter months, it would translate into much less during the ensuing summer months.

Hydropower makes up 66 per cent of Washington State's generated electricity, and demand is greatest during the winter months when heating and lighting requirements are at their maximum. It is in contrast to just about everywhere else in North America, where demand is highest during the summer to power air conditioners.

Ironically for Washington State, global warming will in fact lower demand during the winter. Recent studies have shown that projected temperature increases of 3-5 degrees Fahrenheit (2-3 Celsius) could reduce monthly winter electricity demand across the Northwest Power Pool by more than 1,000 megawatt-months by 2040. Despite an increase in demand during the summer, it will create a net annual decrease in demand over the year.

The increase in streamflow during the winter months will increase generation and revenues during the short term, with winter gains outstripping summer losses. But the benefits will only last until 2040, when summer losses begin to overwhelm winter gains.

Hydro power has been as reliable as, well, Old Faithful, with many units still churning out power since their construction in the 1920s and '30s. It would be ironic indeed if global warming made obsolete these modern-day power pyramids long before the machines that keep them humming did.

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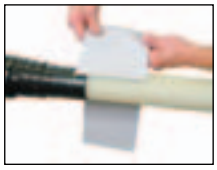
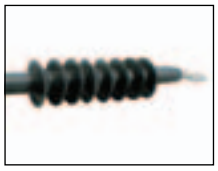

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THE FUTURE OF ELECTRICITY

By Stuart Baird, M. Eng., MBA

Hydroelectric power plants convert the kinetic energy contained in falling water into electricity. The energy in flowing water is ultimately derived from the sun and is, therefore, constantly being renewed.

Energy contained in sunlight evaporates water from the oceans and deposits it on land in the form of rain. Differences in land elevation result in rainfall runoff and allow some of the original solar energy to be captured as hydroelectric power.

Hydro Quebec's James Bay hydroelectric dam

Hydropower is currently the world's largest renewable source of electricity, accounting for 6 percent of worldwide energy supply or about 15 percent of the world's electricity. In Canada, hydroelectric power is abundant, supplying 60 percent of the country's electrical needs. Traditionally thought of as a cheap and clean source of electricity, most large hydroelectric schemes being planned today are coming up against a great deal of opposition from environmental groups and native people.

HISTORY OF HYDROPOWER

The first recorded use of water power was a clock, built around 250 BC.

Since that time, humans have used falling water to provide power for grain and saw mills, as well as a host of other applications. The first use of moving water to produce electricity was a water wheel on the Fox River in Wisconsin in 1882, two years after Thomas Edison unveiled the incandescent light bulb. The first of many hydroelectric power plants at Niagara Falls was completed shortly thereafter.

Early hydroelectric power plants were much more reliable and efficient than the fossil-fuel-fired plants of the day. This resulted in a proliferation of small-to medium-sized hydroelectric generating stations distributed wherever there was an adequate supply of moving water and a need for electricity. As electricity demand soared in the middle years of this century, and the efficiency of coal- and oil-fueled power plants increased, small hydro plants fell out of favor. Most new hydroelectric development was focused on huge "mega-projects."

The majority of these power plants involved large dams which flooded vast areas of land to provide water storage and therefore a constant supply of electricity. In recent years, the environmental impacts of such large hydro projects are being identified as a cause for concern.

It is becoming increasingly difficult for developers to build new dams because of opposition from environmentalists and people living on the land to be flooded.

This is shown by the opposition to projects such as Great Whale (James Bay II) in Quebec and the Gabickovo-Nagymaros project on the Danube River in Czechoslovakia.

HYDROELECTRIC POWER PLANTS

Hydroelectric power plants capture the energy released by water falling through a vertical distance and transform this energy into useful which converts the water's energy into mechanical power. The rotation of the water turbines is transferred to a generator which produces electricity. The amount of electricity which can be generated at a hydroelectric plant is dependent upon two factors. These factors are (1) the vertical distance through which the water falls, called the "head," and (2) the flow rate, measured as volume per unit time.

The electricity produced is proportional to the product of the head and the rate of flow. The following is an equation which may be used to roughly determine the amount of electricity which can be generated by a potential hydroelectric power site:

$$\text{POWER (kW)} = 5.9 \times \text{FLOW} \times \text{HEAD}$$

In this equation, FLOW is measured in cubic meters per second and HEAD is measured in meters.

Based on the facts presented above, hydroelectric power plants can generally be divided into two categories. "High head" power plants are the most common and generally utilize a dam to store water at an increased elevation. The use of a dam to impound water also provides the capability of storing water during rainy periods and releasing it during dry periods. This results in the consistent and reliable production of electricity, able to meet demand. Heads for this type of power plant may be greater than 1,000 m. Most large hydroelectric facilities are of the high head variety. High head plants with storage are very valuable to electric utilities because they can be quickly adjusted to meet the electrical demand on a distribution system.

"Low head" hydroelectric plants are power plants which generally utilize heads of only a few meters or less. Power plants of this type may utilize a low dam or weir to channel water or no dam and simply use the "run of the river". Run-of-

Continued on Page 11

DATA SHEET

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ARC FLASH REDUCTION SWITCH

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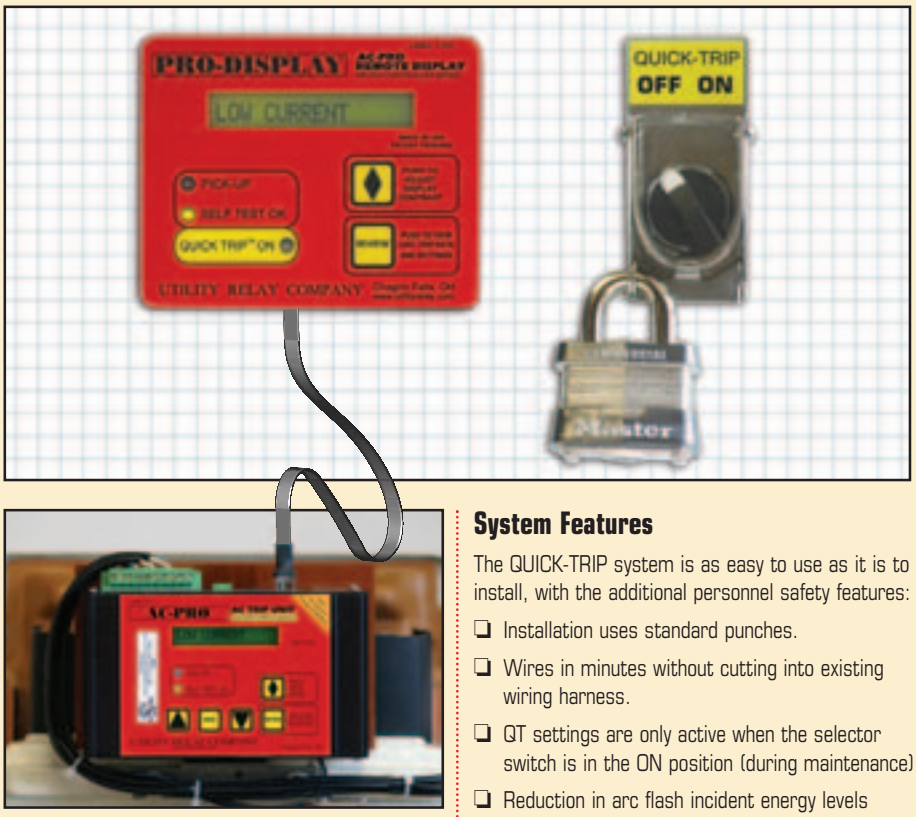
Since arcflash potential is directly related to breaker clearing time, the QUICK-TRIP system provides an easy and safe method to reduce fault-clearing time without opening a cubicle door to reprogram the trip unit.

The QUICK-TRIP system is activated by means of a padlockable selector switch. When enabled, two additional settings are activated in the AC-PRO trip unit to provide enhanced protection:

- ❑ QT Instantaneous
- ❑ QT Ground Fault

These two individually programmable settings are designed to provide faster clearing times in the event of a fault.



System Features

The QUICK-TRIP system is as easy to use as it is to install, with the additional personnel safety features:

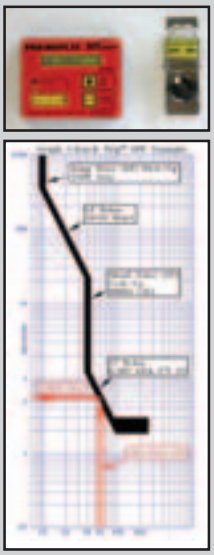
- ❑ Installation uses standard punches.
- ❑ Wires in minutes without cutting into existing wiring harness.
- ❑ QT settings are only active when the selector switch is in the ON position (during maintenance).
- ❑ Reduction in arc flash incident energy levels may permit lower PPE clothing for maintenance personnel.
- ❑ Padlocking switch can be incorporated into a lock-out tag-out procedure.
- ❑ QUICK-TRIP ON LED confirms operation.
- ❑ SELF-TEST LED verifies trip unit operation.
- ❑ PICK-UP LED indicates overcurrent situations.
- ❑ QUICK-TRIP settings can be reviewed on the external PRO-DISPLAY.
- ❑ Last Trip Data and all settings can be reviewed on the PRO-DISPLAY.
- ❑ 3-phase currents are displayed continuously on the PRO-DISPLAY.
- ❑ The system is fully powered by the trip unit's CTs. No aux power or batteries.
- ❑ Extra contacts on the selector switch are available for external annunciation.

Practical Example

A technician needs to rack out a feeder breaker for maintenance. In so doing, he is the minimum 18" away from any potential arc flash source in the cubicle. As the breaker is being racked out, a 12,000 amp arcing fault occurs inside the cubicle. The 2000A main breaker sees the fault and trips, subsequently clearing the fault in the feeder breaker cubicle.

The two graphs below illustrate the dramatic impact that arc-clearing time has on incident energy levels.

Given that: **F = 12kA** and **D = 18 in.**

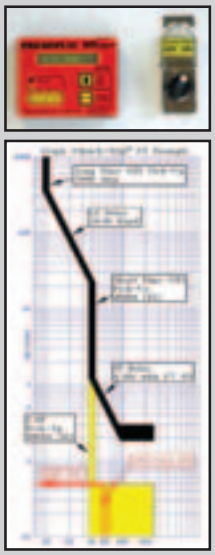


Graph 1:
QUICK-TRIP: **OFF** shows the trip time characteristics of the main breaker.

- ❑ The AC-PRO will cause the main breaker to clear the 12kA fault in .556 seconds (based on a Short-Time Delay of .20 seconds with I^2t ON). The resulting arc duration will be: **t = .556**
- ❑ The resulting incident energy is: **E_I = 25.8022**
- ❑ The Hazard Risk Category is: **4**

Graph 2:
QUICK-TRIP: **ON** shows the trip time characteristics of the main breaker.

- ❑ The AC-PRO will now cause the main breaker to clear the 12kA fault .05 seconds (based on the Instantaneous QT or I QT Pick-Up setting of 8000 amps). The resulting arc duration will be: **t = .05**
- ❑ The resulting incident energy is: **E_I = 2.3203**
- ❑ Hazard Risk Category reduced to: **1**



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Continued from Page 9

the-river generating stations cannot store water, thus their electric output varies with seasonal flows of water in a river. A large volume of water must pass through a low head hydro plant's turbines in order to produce a useful amount of power. Hydroelectric facilities with a capacity of less than about 25 MW (1 MW = 1,000,000 watts) are generally referred to as "small hydro", although hydroelectric technology is basically the same regardless of generating capacity.

"Pumped storage" is another form of hydroelectric power. Pumped storage facilities use excess electrical system capacity, generally available at night, to pump water from one reservoir to another reservoir at a higher elevation. During periods of peak electrical demand, water from the higher reservoir is released through turbines to the lower reservoir, and electricity is produced. Although pumped storage sites are not net producers of electricity - it actually takes more electricity to pump the water up than is recovered when it is released - they are a valuable addition to electricity supply systems. Their value is in their ability to store electricity for use at a later time when peak demands are occurring. Storage is even more valuable if intermittent sources of electricity such as solar or wind are hooked into a system.

ENVIRONMENTAL IMPACTS

Hydroelectric power plants have many environmental impacts, some of which are just beginning to be understood. These impacts, however, must be weighed against the environmental impacts of alternative sources of electricity. Until recently there was an almost universal belief that hydropower was a clean and environmentally safe method of producing electricity. Hydroelectric power plants do not emit any of the standard atmospheric pollutants such as carbon dioxide or sulfur dioxide given off by fossil-fuel-fired power plants. In this respect, hydropower is better than burning coal, oil, or natural gas to produce electricity, as it does not contribute to global warming or acid rain.

Similarly, hydroelectric power plants do not result in the risks of radioactive contamination associated with nuclear power plants.

A few recent studies of large reservoirs created behind hydro dams have suggested that decaying vegetation, submerged by flooding, may give off quantities of greenhouse gases equivalent to those from other sources of electricity. If this turns out to be true, hydroelectric facilities such as the James Bay project in Quebec that flood large areas of land might be significant contributors to global warming.

Run-of-the-river hydro plants without dams and reservoirs would not be a source of these greenhouse gases.

The most obvious impact of hydroelectric dams is the flooding of vast areas of land, much of it previously forested or used for agriculture.

The size of reservoirs created can be extremely large. The La Grande project in the James Bay region of Quebec has already submerged over 10,000 square kilometers of land; if future plans are carried out, the eventual area of flooding in northern Quebec will be larger than the country of Switzerland. Reservoirs can be used for ensuring adequate water supplies, providing irrigation and recreation, but in several cases they have flooded the homelands of native peoples whose way of life has then been destroyed.

> ***The La Grande project in the James Bay region of Quebec has already submerged over 10,000 square kilometers of land.***

Damming a river can alter the amount and quality of water in the river downstream of the dam, as well as prevent fish from migrating upstream to spawn. These impacts can be reduced by requiring minimum flows downstream of a dam and by creating fish ladders which allow fish to move upstream past the dam. Silt, normally carried downstream to the lower reaches of a river, is trapped by a dam and deposited on the bed of the reservoir. This silt can slowly fill up a reservoir, decreasing the amount of water which can be stored and used for electrical generation. The river downstream of the dam is also deprived of silt which fertilizes the river's floodplain during high water periods.

Bacteria present in decaying vegetation can also change mercury, present in rocks underlying a reservoir, into a form which is soluble in water.

The mercury accumulates in the bodies of fish and poses a health hazard to those who depend on these fish for food. The water quality of many reservoirs also poses a health hazard due to new forms of bacteria which grow in many of the hydro rivers. Therefore, run-of-the-river type hydro plants have a smaller impact on the environment.

THE FUTURE OF HYDROELECTRIC POWER

The theoretical size of worldwide hydropower is about four times greater than that which has been exploited at this time. The actual amount of electricity which will ever be generated by hydropower will be much less than the theoretical potential. This is due to the environmental concerns outlined above, and economic constraints. Much of the remaining hydro potential in the world exists in the developing countries of Africa and Asia. Harnessing this resource would require billions of dollars, because hydroelectric facilities generally have very high construction costs. In the past, the World Bank, has spent billions of foreign aid dollars on huge hydroelectric projects in the Third World. Opposition to hydropower from environmentalists and native people, as well as new environmental assessments at the World Bank will restrict the amount of money spent on hydroelectric power construction in the developing countries of the world.

In North America and Europe, a large percentage of hydropower potential has already been developed. Public opposition to large hydro schemes will probably result in very little new development of big dams and reservoirs. Small-scale and low head hydro capacity will probably increase in the future as research on low head turbines and standardized turbine production reduces the costs of hydroelectric power at low-head sites.

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IT SECURITY COSTS: OUTSOURCING VERSUS SELF-DEPLOYMENT

By Ron Lepofsky

In my article of July 2005 I identified the business reasons why mundane IT processing of information security should be outsourced to a third party. In this article I identify the financial calculations to quantify how outsourcing raw processing such as analysis and correlation of huge amounts of SCADA or SOX (Sarbanes-Oxley Act) related security data can generate considerable cost savings

Electrical utilities, like all other industries, are faced with securing their infrastructure in a timely yet cost effective manner. The short term life span of IT security deployments are a very different than long term power generation and transmission capital investments.

The short lifecycle cost of an IT security deployment and time to deploy can be optimized by utilizing outsourced IT security services. While this concept may seem somewhat alien to an industry steeped in a tradition of large and long term capital acquisition, the financial justification can be simply calculated.

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COST COMPARISONS

Objectively comparing the costs of outsourcing vs. purchasing and managing information security technology, on a three year cost of ownership basis, can yield some surprising results in favour of outsourcing. This is particularly true when the analyst include factors such service level agreements (SLA) to which either the in-house technology team or outsourcer must comply, and sometimes forgotten costs such as:

1. Unaccrued tax deductions for capital acquisitions.
2. Ongoing maintenance of the technology.
3. Ongoing subscription (signatures).
4. Training and retraining (due to employee turnover).
5. Adhering to Service Level Agreements.
6. Replacing unsupported or outdated technology - Life cycle costs.
7. Auditing. (Outsourcers should not audit themselves.)
8. Time to deploy (Timeliness of deriving benefits of the project.)
9. Taste test. (Verifying both the business value and the acceptability of a specific actual implementation.)

These points may be more clearly illustrated in an example cost analysis of an Intrusion Detection System (IDS). Of course this analysis can be similarly applied to more sophisticated outsourced security services, such as IDS analysis and remedial recommendations, or (SOX, SCADA) event log correlation and remedial recommendations.

In our example case, as shown in Figure 1, the three-year life-cycle project cost is minimized by the outsourcing alternative, which is 52% of the three-year cost for an in-house deployment. The total three year cost for in-house deployment is $345,100 vs. $180,000 for outsourcing.

ALL-IN COSTS

1. The unaccrued tax credits are calculated for the in-house solution, based upon the appropriate capital cost depreciation for each company, and this per cent age will vary by taxation jurisdiction. In this example, 30% depreciation is used. The significance of including this point is its implication on cash flow for the company, and on tax credits, both of which are significant to the CFO and controller.

This point is a non-issue for outsourcing, as 100% of outsourcing costs are tax deductible. From a tax perspective, outsourcing provides a simple and distinct benefit.

Alternatively, this tax issue is completely eliminated by leasing rather than by purchasing as a capital acquisition. In this case, monthly lease costs would replace unaccrued tax credits in our example.

2. Annual maintenance costs, which can be as high as 20% of initial capital costs, of course are included with the in-house solution, but are irrelevant for the outsourcing solution.

3. Annual subscriptions to signatures and more generally updates to patterns for pattern recognition technology such as anti-virus, anti-Spam, and web browsing URLs, is an often forgotten cost. The author has seen several instances where purchasers erroneously assumed that subscription costs were included as maintenance. Not so.

Similar to maintenance costs, the subscription costs apply to the in-house solution, but should be included as part of a monthly outsourced solution.

4. The costs of training in-house installation, operations, and end-user support staff can be significant, especially depending upon the significance of the application to the end-users. Training of course impacts both SLA commitments to end-users and the amount of time in-house staff are absent while attending training courses.

The training cost estimates in our example are conservative, and assume that course costs are $2,500 for one week, for two employees. Travel and travel expense costs are not included in this example for simplicity, but they can easily be $2,000 per employee and should not be overlooked.

The author has included training costs additionally in the second year in order to account for staff changes due to promotions and other internal movements and of course due to employee turnover.

5. Service Level Agreements with end-user groups have an inherent, but often overlooked cost for in-house solutions. Outsourcers certainly account for the cost of an SLA, and naturally use guarantees of service as sales tools.

While the SLA costs are shown in our example as included with the monthly outsourcing price, they are described as "soft costs" for the in-house solution, based upon the assumption that the existing implementation, operations, and end-user support staff have the time to deal with the new security technology project. The soft costs are calculated on the pro-rated estimated time that the support staff would spend on the project.

Two common errors in calculating these soft costs are when the cost to adhere to a stringent SLA is underestimated, and when additional staff needs to be hired with real and not with soft currency.

Outsourcers have an inherent cost advantage in the support and SLA adherence area for two reasons, as follows:

a.) They can minimize response times to pending disasters, when they see a common problem occurring simultaneously across several unrelated clients.

b.) They spread the support costs for a specific solution such as IDS, across several clients, and can therefore afford a more robust depth of support.

Continued on Page 15

Comparison of In-House vs. Outsourced IDS Costs for Three Year Project Life Cycle

Costs in $	Variables	First Year	Second Year	Third Year	Total 3 year comparison
In-House Solution					
Purchase price of IDS technology, including hardware platforms.	$45,000 to $60,000	$60,000	$0	$0	
Annual technology maintenance costs.	12%	$7,200	$7,200	$7,200	
Unaccrued tax credits, based upon:		$21,000	($9,000)	($9,000)	
1. Annual depreciation rate for technology.	30%				
2. Corporate tax rate.	50%				
Training estimated at $2,000-$5,000 plus travel; needed for 2 employees.		$5,000	$2,500	$5,000	
Soft costs of employees maintaining the IDS technology.	$5,000	$60,000	$60,000	$60,000	
Soft costs of employees implementing the IDS technology.		$8,000			
Cost of upgrades or of replacing non-supported or outdated technology.				$30,000	
Audit costs.		$5,000		$5,000	
Costs of delayed deployment.		$20,000			
Annual costs		**$186,200**	**$60,700**	**$98,200**	**$345,100**
Outsourcing Solution					
Annual maintenance, signature subscription, and training.		$0	$0	$0	
Outsourcer installation and implementation costs.		$8,000	$0	$0	
Outsourcer monthly costs, accounting for SLA.	$4,500	$54,000	$54,000	$54,000	
Audit Costs.		$5,000		$5,000	
Costs of delayed deployment.		$0			
Annual costs		**$67,000**	**$54,000**	**$59,000**	**$180,000**
Cost Savings with Outsourcing		**$119,200**	**$6,700**	**$39,200**	**$165,100**

Figure 1

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Continued from Page 13

6. Lifecycle costs of technology should be irrelevant in an outsourced solution, where the problem of keeping a solution current rests with the outsourcer. However, this responsibility should be financially recognized at the financial planning stage of an in-house project. Many of us have encountered our favourite technology suddenly being put in jeopardy because of a corporate acquisition or corporate failure.

The author has accounted for this potential cost with a placeholder value of $30,000 in the third year, with accompanying costs of re-training of $5,000.

7. Outsourcers along with any other security technology implementer should not audit themselves, as best practices would dictate. Therefore, it is useful to include costs of auditing for both outsourced and in-house solutions.

8. Delayed time to deploy could have real currency costs, if a regulatory compliance, revenue generating or cost saving project implementation is put on hold until the security project is fully complete. A timely example would be to delay a HIPAA or other privacy compliancy project until the appropriate security (IDS in this example) technology is in place.

The example analysis has a line for the cost of extended delays in both the in-house and outsourcing solutions, for comparative purposes. Since this cost is so uniquely dependent upon each situation, the author has recognized the need to account for it, but has not made any attempt to quantify the cost of extended time to deploy.

9. Time to deploy may be reduced by a proof of concept or taste test. The cost for a sample four-month proof of concept is shown for our example of an outsourced solution as Figure 2 below. The cost is $26,000, which may be very reasonable, as a low risk and low time to deploy proof of concept.

Outsourcer 4 Month Proof of Concept Cost		
IDS technology, support, and training		$0
Outsourcer installation and implementation		$8,000
Outsourcer Monthly Costs	$4,500	$18,000
Four Month Total		**$26,000**

Figure 2

An outsourcer could make such a four-month trial part of an annual contract, should the client wish to proceed with the project.

CONCLUSION

At first, blush directly purchasing information security technology and managing the project in-house can appear less expensive than an outsourced alternative. However, after taking into account the more subtle costs of tax implications, ongoing training, the real currency costs of operations, complying with an SLA to end-users, and the cost of risk, an outsourcing alternative can be much less expensive, particularly over a three-year project life cycle.

Ron Lepofsky is the President and CEO of ERE Information Security Auditors, who are information security and financial disclosure/privacy compliance auditors.

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- Application of Fish Friendly Criteria in the Design of a "Vaneless" Turbine;
- Conowingo Unit 5 Rehabilitation: What Went Well And What Didn't;
- Flow Field Measurement around a Guide Vane with Particle Image Velocimetry;
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JOB HUNTING

INTERFACING OPTICAL CURRENT SENSORS IN A SUBSTATION

By J. D. P. Hrabliuk, B. Sc. E.E., P. Eng.

I INTRODUCTION

The various components required to build the digital substation of the future are now available for utilities to purchase. These components lead to improved measurement, control, and protection of the substation with the expectation that lower costs and increased revenue will be achieved with the additional information, which is more accurate and accessible by the various users.

Utilities have come to realize that knowledge on a real time basis enables improved decisions, and hence leads to real economic benefits.

With any new technology there is always enthusiasm and excitement about how the new development will revolutionize older technology, and most people will embrace the fundamental concept of the new technology.

However, once the fanfare has died down, budgets are determined, resources assigned, and staff trained, there remain the headaches associated with integrating new technology. How will the designer interface the new technology with the existing infrastructure, without upgrading all components, and complete this task in a realistic timeframe? Demonstrating to utilities a fully working installation that meshes new and old goes a long way in convincing skeptics that the technology works, and that it will not complicate their jobs.

When the practical problem of integrating existing technology with advanced equipment, which has digital outputs and communications capability, is taken on, most designers will begin to pull out their hair and grunt to themselves, and their colleagues, in the hallways of the workplace. It is not a trivial task to accomplish. New must blend with old as seamlessly as possible. With this goal in mind, electronic outputs representing the measured value, which vary from digital to high energy 1A output signals, provide a solution that does not require a wholesale changeout of the old technology. Given a variety of available interfaces, the benefits of new technology can be combined with existing substation equipment and the user sees a clear migration path for future upgrades.

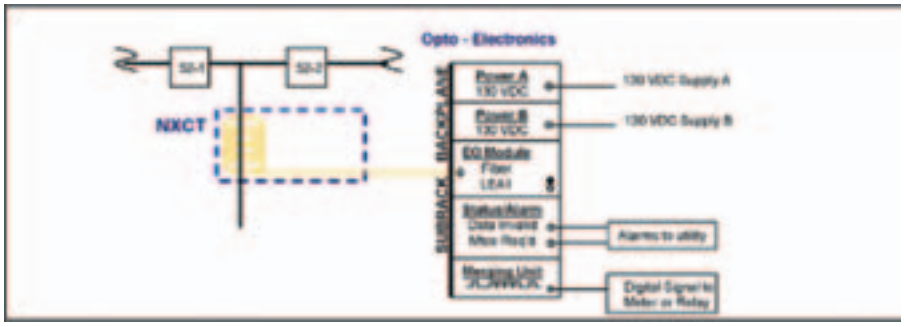

Fig. 1 Optical current sensor with digital output to digital meter or relay.

II INTERFACE OPTIONS

Interfacing optical current sensors with conventional meters and relays requires a fresh approach to bring signals into these devices. In conventional CTs, outputs are either 1A or 5A nominal for both metering and protection applications. These high energy output levels, while commonplace and easy to achieve from "iron core" CTs, are difficult and expensive to replicate using electronics based on an inherently digital signal.

While generally agreed that digital signals from measuring devices will dominate future substations, the short-term solution requires interfacing the devices with an existing analog substation infrastructure. How can a user who wishes to benefit from the use of optical sensing technology best implement these devices without resorting to a specific manufacturers complete product line, or without purchase of a "turn key" substation? Additionally, what communication protocol should be used? When international organizations have difficulty in establishing agreed upon standards, utility engineers in turn face difficulty implementing the digital substation. A complete digital substation will inevitably be available in the future, but how will it come about? The majority of the pieces are available today, but the difficulty lies in interfacing with older incompatible technology. Standards are still evolving. Manufacturers of meters and relays require time to evolve to fully digital inputs and, most importantly, people have differing opinions about the optimal path to a complete digital solution. Substation designers want an immediate solution that will be flexible enough to mate with existing equipment yet be capable of evolving for the future.

One approach is a staged evolution. The transition to a complete digital substation can evolve by providing several simple methods to integrate old with new. New technology will find acceptance if users are given interface options that are easy to implement, similar to existing technology, which still provide the additional benefits of an advanced technology. When digital interface protocols are finalized and accepted by all parties involved, optical sensors will be in a position to provide these digital signals as an ideal technical interface. Interface options presently available to a user of an optical sensor include digital, low energy analog and high energy analog outputs. This range of interfaces gives users flexibility in their designs.

A: Digital Output

The digital output from an optical current sensor, representing the primary current flowing, is available in a format consistent with IEC draft standard

60044-8. This draft standard specifies the digital signal that will emerge from a "merging unit" (MU), shown in Figure 1. The MU's function is to gather information from up to seven current transducers (3 measuring CTs, 3 protective CTs, and one neutral CT), and up to five voltage transducers (3 measuring/protective VTs, one busbar VT, and one neutral VT) whose signal is either of a digital format or an analog voltage output.

It is recognized that digital standards pertaining to substation communications for relaying, control, and data acquisition are evolving with many in various stages of becoming standards, such as IEC 60044-8, IEC 61850, and IEEE P1525. To further complicate the goal of using digital communications within substations, standards may be issued, but they must still gain acceptance with a large portion of the vendors and within the utility community.

Utilizing the digital signal for either metering or relaying gives the user the most accurate signal available, as compared to the low and high energy analog signals, at a lower cost. By not converting the digital signal to the analog domain, and possibly amplifying this signal, results in the greatest accuracy and dynamic range performance from the sensor with a lower overall cost.

B: Low Energy Analog (LEA) Output

A low energy analog output from the electronics is selectable with several ranges depending on the user's requirements. For metering applications, the analog signal representing the primary current can be 2VRMS or 4VRMS nominal. The choice will depend on the meter interface available to the user. When using the signal for relaying, current would be represented by a 200 mVRMS signal capable of 11.3 Vpeak. The 11.3 Vpeak signal gives a maximum instantaneous value consistent with the worstcase fault condition that is 40 times the primary current.

Figure 2 details a low energy analog (LEA) solution for either metering or relaying.

The LEA option while applicable for both metering and relaying is ideally suited for protection applications.

Relays are commercially available today to accept LEA signals from an optical CT. The LEA output, while not as accurate as the digital output signal, remains as an interim step until fully digital meters and relays are made available to users. Reduction in accuracy, when compared with the digital output signal, can be on the order of 0.1% over the full range of the optical sensor.

C: HIGH ENERGY ANALOG OUTPUT

In order to mate new optical sensors with conventional meters, a digital signal from the opto-electronics is converted to an amplified 1A analog signal which can be fed into various manufacturers meters, as shown in Figure 3. The high energy analog signal is only compatible with meters since reproducing a 1A signal for relaying is both impractical and expensive. Similarly, a 5A analog output signal is not available for either metering or relaying for the same reasons. The 1A analog output can be utilized by several types of meters, and in the interim before a digital solution is available; will allow use of optical sensors within substations. A power amplifier that is fully compliant with all EMC, transient, and surge requirements allows it to be paralleled with a conventional CT. With this capability, an optical sensor can sum signals at a node.

In Figure 4 an analog amplified signal is integrated with a conventional CT.

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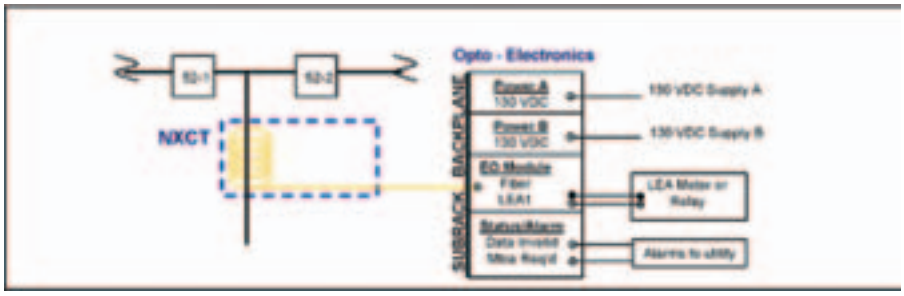

Fig. 2 Optical current sensor with low energy analog (LEA) output to analog meter or relay.

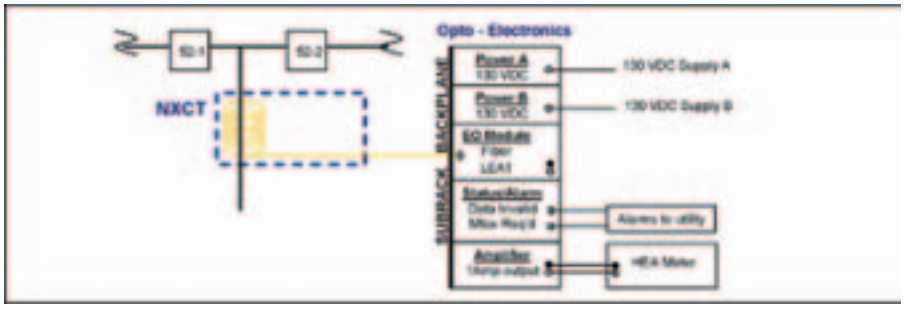

Fig. 3 Optical current sensor with high energy analog (HEA) output to analog meter.

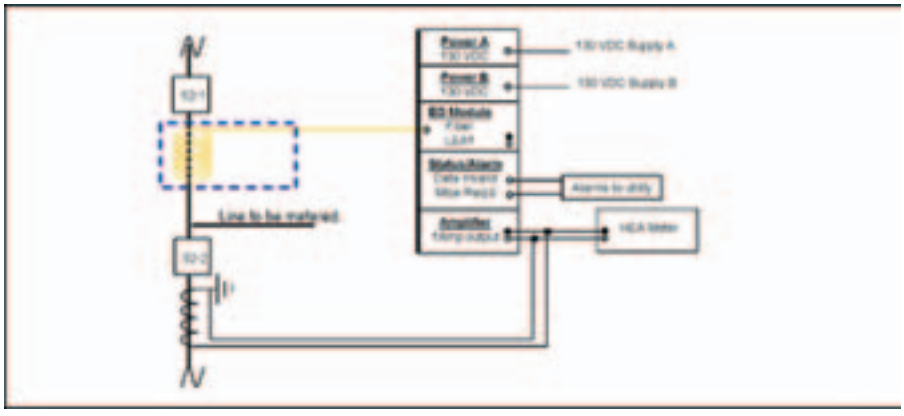

Fig. 4 High energy analog (HEA) output summed with conventional CT

Continued from Page 17

III SELECTION OF AN OPTICAL CURRENT SENSOR FOR METERING

Optical sensors are inherently different from conventional iron core transformers. They measure the primary current based on optical sensing and create a digital representation of the current. This signal may be converted back into an analog signal and possibly amplified. When utilizing optical sensors, users must be aware of the implications of the various available sensor designs, as they may see peculiar results from their meters, especially at low primary currents.

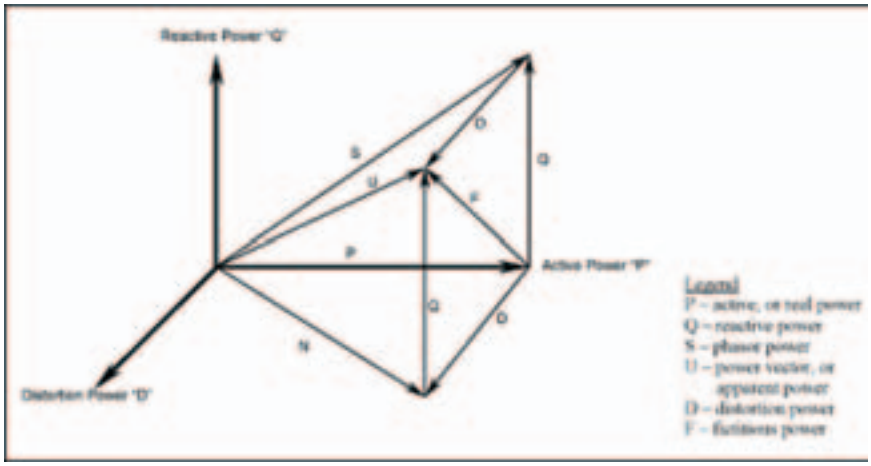

Fig. 5 IEEE Std. 100 definition of the "Power Vector" U

The observed peculiarities, and their dependence to the design of the optical sensor, are due first to the amount of noise contained within the output signal, and secondly to the method of calculating certain parameters within a manufacturer's meter. The first can be controlled by sensor manufacturers, the second can vary from meter to meter and therefore has limited ability to be modified. To achieve a successful metering system design, suitable for all available meters, the noise from the sensor must be reduced. Noise contribution, or alternatively, sensitivity of an optical current sensor, is important because meters may report incorrect results, such as high VARs, incorrect power factor, or high harmonic distortion. These incorrect readings will appear at low current levels, but depending on the design of the sensor, low may mean 100A or more flowing on the primary. By designing a sensitive sensor, as described in sections 4 and 5, the noise dependence can be reduced to a level below 5A primary, where it becomes insignificant.

In order to understand the implications of sensor design to metering, a more thorough description of metering and metering terminology is required.

Metering systems have become a critical component in the deregulation of the power system as generation, transmission, distribution, and operations are being separated into independent companies. With this break up of the utilities, an increasing number of metering points are being added, as power is no longer flowing within the same company. The power is crossing boundaries and money is exchanging hands. Metering has become more important and people associated with buying and selling power want to measure it with increased accuracy, at more places, and in the most cost effective manner possible.

Metering personnel generally may want to know how much power is flowing into and out of their system and at what power factor? A simple question that should be easy to answer, but will bring up more questions if it is to be properly answered. Do you want real or reactive power flow? This question is easy to answer and well understood, but what if someone wants to know what the phasor power is, or how much of the apparent power is due to distortion, or fictitious power? Distortion and fictitious power are not commonly understood, but become relevant terms when measuring signals with high harmonic content, or noise. These metering terms can be found in IEEE Standard 100-1996[1], "The IEEE Standard Dictionary of Electrical and Electronics Terms". This standard explains several terms not traditionally used when discussing metering, but they are essential if currents with high harmonic content are being metered or if noise is significant in a sensor.

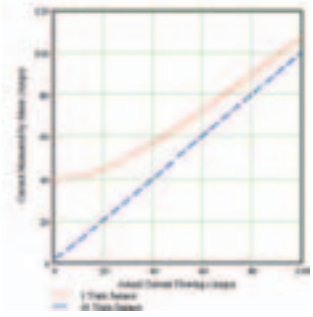

Figure 6 Current measured by "true RMS" meter plotted against actual RMS current.

The flow of power in any circuit is composed of real, reactive, and distortion power vectors, all of which form the "vector power (U)", in a circuit. Figure 5 illustrates the "power vector" components, followed by a brief description of the various components. (Note: For an in depth description of each definition, consult with the IEEE standard.)

Some metering books define the various metering parameters, similar to the IEEE definitions above, but in less detail. However, many do not specifically refer to "distortion power", or "phasor power", and most power terms are defined for "sinusoidal quantities" only. This simplification ignores the vector component that noise and harmonics introduce to power calculations. In the omission of these details, it confuses the reality of the situation by its lack of definitions, which do not give the required "language" to properly explain the power vector (U), as defined in IEEE Standard 100.

For example, power within a meter can be given on a per phase basis and a total polyphase power reading. Not always given by meter manufacturers, though, is a concise definition of what these display values actually are. For some meters, the per phase power is the apparent power per phase, and the total power is the phasor power; but they are all referred to as "power". Similarly, power factor can also be given on a per phase and total basis, both referred to as "power factor", but the per phase power factor is actually arithmetic power factor, and the total is phasor power factor.

The lack of concise information regarding power and power factor calculations may be typical to many meters, however, with an increasing emphasis on understanding harmonics, knowing which vector component of power is displayed by a meter becomes critical to all users.

IV OPTICAL CURRENT SENSORS FOR METERING

In order to reduce signal noise in an optical current sensor, one successful method is to wrap multiple turns of fiber around the conductor, thereby increasing the sensitivity of the device

and "pushing" the noise level down to a level where it is insignificant. By increasing the fiber turns, the resulting signals replicated by the opto-electronics will provide meters with a signal that has superior signal-to-noise ratio (SNR) and, therefore, will be able to be used with any meter, not just a customized meter matched to the characteristics of the sensor. Most utilities having one or possibly two meter manufacturers that they use on a regular basis, and these meters are accepted by all users, installers, and integrators of the meters. To inform them that their meter, which they have invested time and money into becoming familiar with and trained in its operation, is incompatible with a particular signal is simply not an option. Reducing the noise component on an optical current sensor allows usage with any meter manufacturer's product.

Figure 6 illustrates the magnitude of the noise component in a single turn and a 16 turn sensor. The single fiber turn sensor, similar in noise sensitivity to a bulk crystal design, will have significant noise throughout the current sensing range, which can cause a meter reading RMS current to read higher current than is actually flowing on the primary line. VAR measurement may also read higher than actual depending on the calculation method. A sensor with several fiber turns pushes the noise to a level far below that of the single turn sensor. The implications of a sensor with increased sensitivity are that a user can use any meter commonly available and it will work with the optical sensor. When a sensor with high noise content is interfaced with available meters, readings will begin to get progressively worse as the current in the primary drops, and hence the SNR of the output signal decreases.

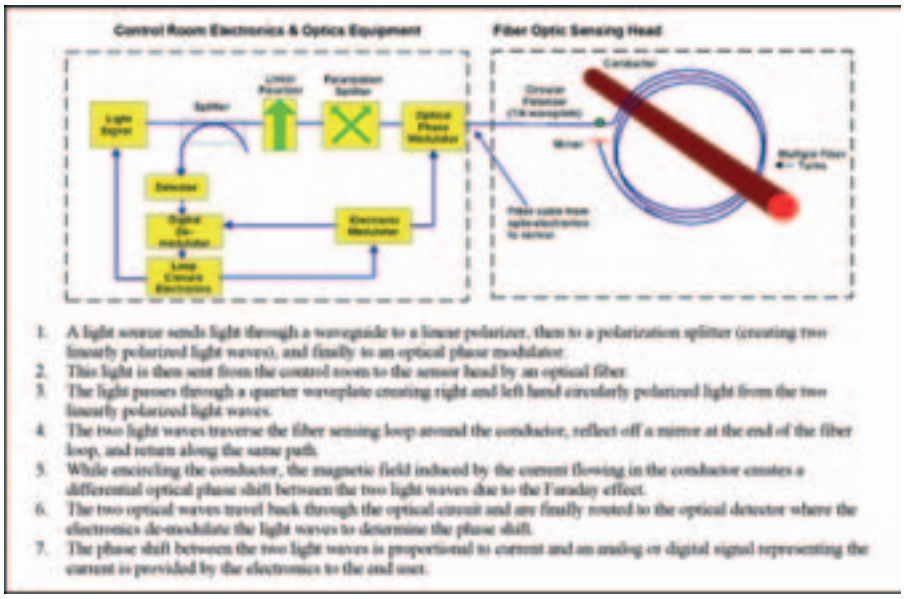

Figure 7: NxtPhase NXCT Fiber Optic Current Sensor Optical Block Diagram

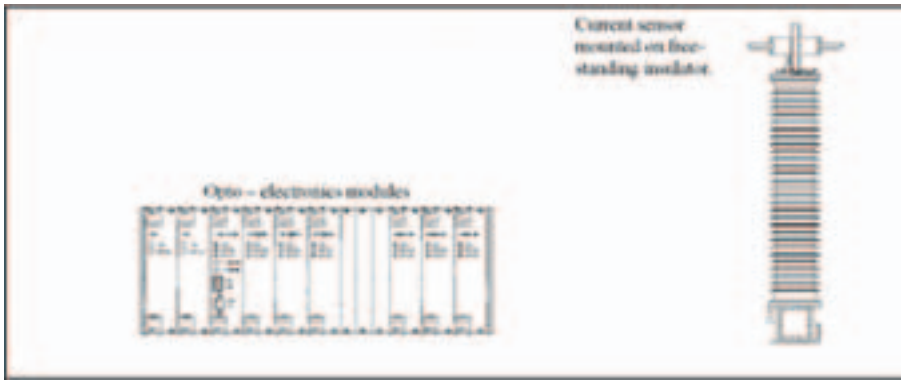

Figure 8 Fiber optic current sensor physical components (NTS)

Therefore, unless the meter examines pure 60 Hz signals, the meter may register incorrect values. Using multiple fiber turns, in conjunction with advanced optics and electronics, can overcome this limitation.

V. FIBER OPTIC CURRENT SENSOR TECHNOLOGY

The fiber optic current sensor is the core of an optical current transducer. As shown in Figures 7 and 8, it consists of a light source, photo detector, optics and electronics coupled to a fiber sensor head wound around a current carrying conductor.

The optical phase modulator is the "heart" of the current sensor and it, along with the electronics and optics, can provide a highly accurate measurement of current.

VI CONCLUSION

Optical current sensors, in principal, perform the same function as conventional magnetic CTs; they measure current on the primary conductor and give an output signal that is representative of the primary current. The main difference to an optical sensor is that the signal is inherently digital in nature.

This digital signal, which is the best signal representing what is actually occurring on the primary conductor, has ability to be converted back into the analog world and amplified. This conversion and amplification of the signal, while highly illogical at first glance, permits optical sensors to be used immediately with available analog meters. When digital interfaces evolve and mature, the optical sensors with their inherent digital signals will be poised to offer further performance benefits with reduced cost, as the digital to analog conversion along with amplification can be eliminated.

Optical sensors are relatively new to the power industry and when interfacing them with existing meters or relays, a user must examine and understand the detailed characteristics of the sensor, since the design can significantly influence overall performance of a metering system.

James Hrabliuk, an Applications Engineer with NxtPhase Corp, graduated from the University of Manitoba in 1989 with a Bachelor's Degree of Science in Electrical Engineering.

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OPTICAL CURRENT, VOLTAGE SENSORS IN AN EHV SERIES CAPACITOR BANKS APPLICATION

By Farnoosh Rahmatian, David Peelo, Greg Polovick, Bruce Sunga, and Jari Lehtimaki

1. INTRODUCTION

Series capacitor banks are applied mainly on long EHV transmission lines with the purpose of increasing the power transfer capability of the line by reducing its effective line impedance and to improve system stability. The 500 kV bank at BC Hydro's Guichon Series Capacitor is typical of a gapped – MOV protected scheme (Figure 1). The circuit arrangement consists of three branches as follows:

• The damping circuit (5RX1 and 5R1) in series with the bypass breaker (5CB1) and triggered sparkgap (5SG1). The purpose of the damping circuit is to limit and damp the capacitor bank discharge current when the bypass breaker is closed or when the sparkgap is triggered during a fault on the line and the capacitor is charged to the bank protective level. Current in the sparkgap is detected by 5SGCT1 and immediately initiates closing of the bypass breaker.

• The capacitor bank is split into four sections as shown to enable unbalance protection (5UBCT1) for detecting capacitor failures.

• The MOV (5MOV1) provides overvoltage protection of the bank in the event of a fault on the line. MOV current is detected by 5MOVCT1 and the energy relay calculates and integrates the energy absorption using the measured current and the VI characteristic of the MOV. When the energy absorption limit is reached, the sparkgap is triggered and bypass initiated.

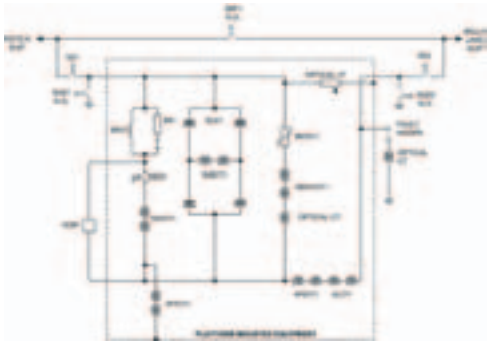

Figure 1. Guichon Series Capacitor Bank one-line diagram.

The equipment as shown within the dashed lines in Figure 1 is mounted on a platform isolated from ground. The platform is at the line potential: the Kelly Lake side of the bank is connected to the line. The purpose of 5FPCT1 is to detect faults to the platform. Current transformer 5LCT1 monitors the line current through the bank and 5PSCT1 provides platform level power for sparkgap firing purposes.

The bank is connected to the line through two isolating disconnectors 5D1 and 5D2. 5BP1 is the bypass disconnector. To insert a bypassed and isolated bank, 5D1 and 5D2 are first closed, then 5BP1 is opened to commutate the current through the bypass breaker and damping reactor circuit. The bypass breaker, 5CB1, is then opened to transfer the current to the capacitor bank.

For purposes of fault testing, a 145 kV optical voltage sensor (VT) was installed between the high voltage side of the bank and the platform to measure the voltage across the bank during steady state and fault conditions (Figure 1). An

optical CT was installed in series with the MOV to measure MOV current. A total of five faults were created by firing a projectile trailing a fuse wire between two hoops; one at ground potential and the second at line potential as shown on the right side of Figure 1. The lower hoop was isolated from ground and an optical CT was installed to measure the primary fault and secondary arc currents. The latter currents occur due to single pole tripping of the line.

The paper describes the optical sensors and a comparison is made between the outputs of the bank standard protection and those from the sensors. The future use of optical sensors in series capacitor applications is discussed.

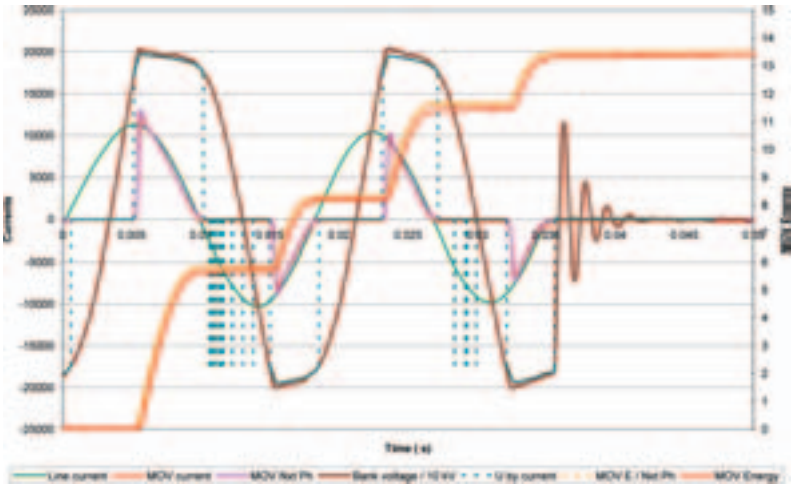

Figure 2. Fault, capacitor and MOV currents and MOV energy.

2. OPTICAL SENSORS

The optical VT used was an NXVT-145, deploying a distributed electric field sensor architecture, see [1] for details. The NXVT was programmed to have a scale factor of 20,125:1 and was set up for measuring voltages between –230 kV and +230 kV. It also had a wide bandwidth, capable of measuring signals between 0.001 Hz and 40 kHz. The fiber optic CTs used were all-dielectric, window type, NXCTs, having an in-line interferometric design, see [2] for details. Both NXCTs for measuring the MOV current and the fault current had scale factors of 1200A:1V and were set up to measure currents between –14 kA and +14 kA.

The bandwidth of the NXCTs used was 6 kHz. Optical fibers, ~ 100 m long, connect the passive sensor heads to the associated electronics in the control room. The digital voltage and current measurements were converted to analog low energy voltages in the sensor electronics chassis. The outputs were sampled at 100,000 samples per second and stored using a multi-channel isolated data acquisition system.

The main reasons for using optical CTs and VTs for this test were the following:

• Wide bandwidth: fault current, MOV current, and MOV voltage were all expected to be very distorted waveforms, rich in frequency content;

• Linearity and wide dynamic range: very wide range of currents and voltages were to be measured without signal distortion. The primary and the secondary fault currents were expected to be about 12 kA and 40 A, respectively, and the wide dynamic range of the NXCT was critical for measuring both signals;

• Galvanic isolation from the HV line: optical isolation from the platform made the installation of the light weight test sensors easy and safe; and

• Galvanic isolation between various ground levels: since the fault was being created in the substation itself, the use of optical fibers solved the safety issue with the rising ground potential in various locations in the substation during the testing.

3. FAULT TEST RESULTS

Traces from the hybrid and optical measuring systems are shown in Figures 2 and 3, respectively.

Figure 2 shows the line current and MOV current measured by the protection system. The MOV current measured by optical sensors is also shown in figure 2. The voltage across the capacitor bank is shown by two curves: one measured by the optical VT (brown) and the other calculated from the MOV current measured by the optical CT, utilizing the MOV V/I characteristics given by the manufacturer. The MOV energies are calculated by two different methods, one using hybrid MOV current and V-I characteristics and the other optical current and voltage. Comparing MOV energies measured by the optical and hybrid system shows that the difference between the results is not significant. The calculated energies were

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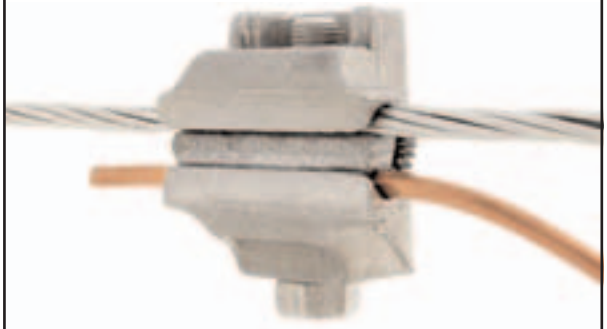

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Continued from Page 23

13.48 MJ measured by NxtPhase optical sensors, and 13.51 MJ measured by Nokian Capacitors protection system.

The difference is well within accuracy specification of the devices used for measurements. The measured voltage was slightly higher than the voltage calculated by the hybrid system using the V/I characteristics.

Figure 3 shows the fault current, MOV current, and MOV voltage measured by the optical system during the fifth staged fault test. As expected, all waveforms were very rich in frequency content.

Figure 3 also shows the MOV energy calculated by integrating the product of MOV voltage and MOV current measured by the optical sensors. The figure shows that the MOVs operate effectively to limit the magnitude of the voltage across the capacitor bank to less than 200 kV; peak currents are about 11 kA.

Figure 4 shows the secondary arc current after the primary fault is cleared by the single pole tripping of the faulted phase.

Voltage on neighboring phases induce sufficient electric field to support a lower energy arc for several hundred milliseconds after the primary fault current arc has created an ionized path between line and ground.

4. HYBRID AND OPTICAL PROTECTION SCHEMES

Figure 5 shows two different ways to replace the hybrid system with the optical system. The left column shows main components of the hybrid system and the next two columns show use of the optical system. The hybrid system consists of traditional current transformers together with signal transmitting electronics on the platform and signal receiving electronics at ground level. The optical system has passive optical CT and PT on the platform and signal processing electronics only at the ground level.

A hybrid system can easily be upgraded using the solution described in the middle column of Figure 5. The traditional CTs will be replaced by optical CTs and ground level electronics will be replaced by NxtPhase electronic units. For new series capacitor applications, the use of a fast serial link will be most attractive since this avoids signal conversions from "digital to analog" and back from "analog to digital".

5. CONCLUSIONS

The fault tests demonstrated the capability of the optical voltage and current sensors to measure highly non-linear signals. While the use of a voltage transformer does not appear to significantly increase the accuracy of the MOV energy calculations in this case, it is anticipated that future series capacitor bank applications will adopt the optical CT technology due to its excellent performance, ease of installation, higher reliability and lower maintenance cost (no electronics on the platform).

Farnoosh Rahmatian, David Peelo, Greg Polovick, Bruce Sunga, and Jari Lehtimaki work for NxtPhase T&D Corporation; DF Peelo & Associates Ltd., British Columbia Hydro, British Columbia Transmission Corporation, and Nokian Capacitors, respectively.

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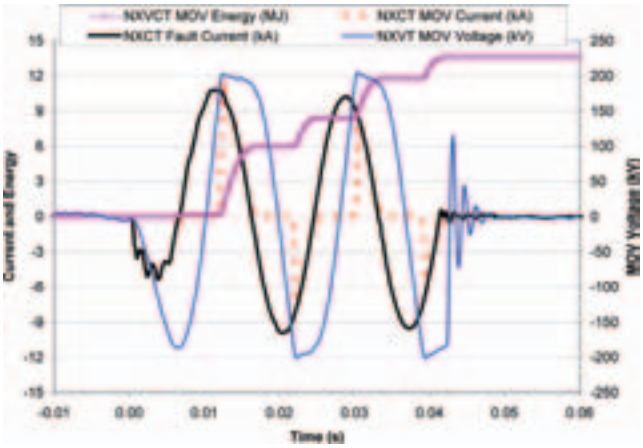

Figure 3. Fault current, and MOV voltage, current and energy measured by optical sensors.

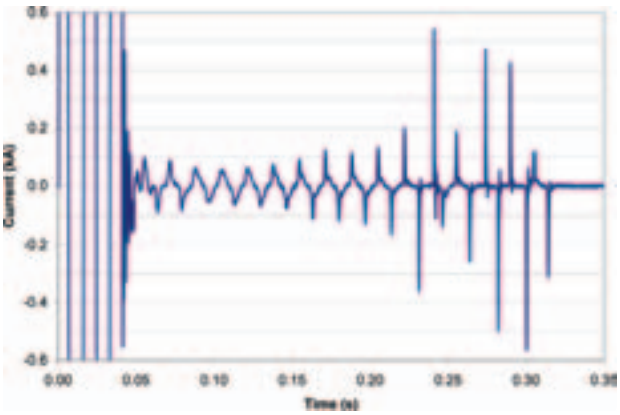

Figure 4. Secondary arc current.

Figure 5. Hybrid based and optical based protection schemes

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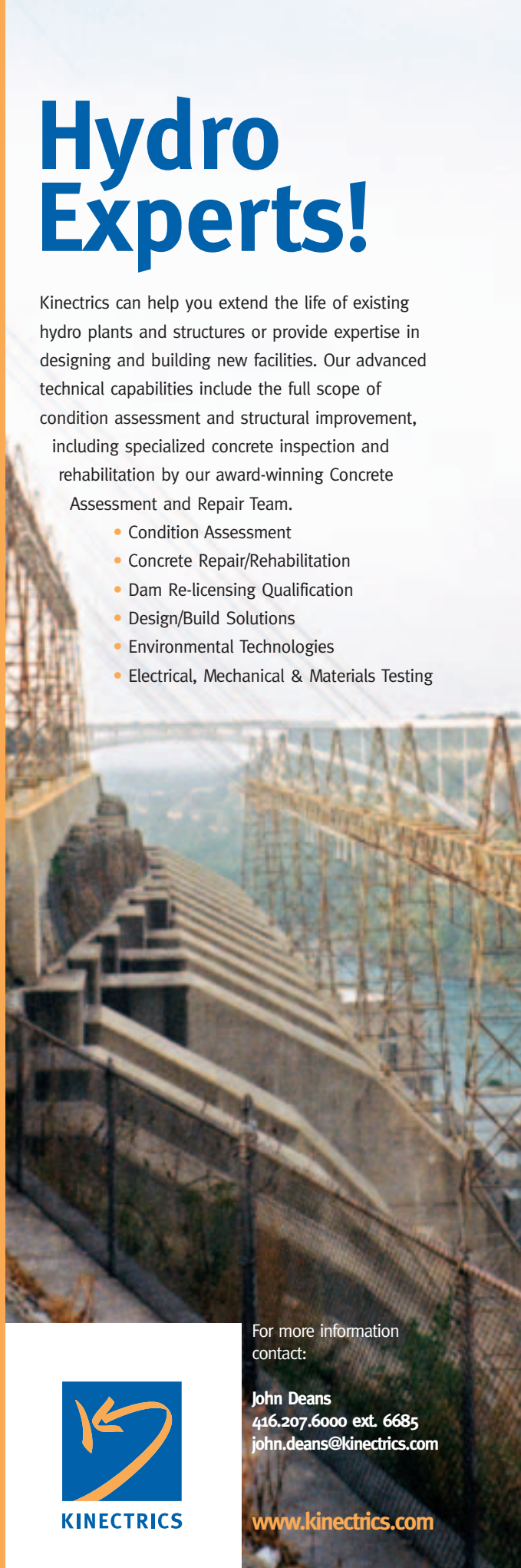

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NEW ON-LINE SF6 LEAKAGE DETECTION SYSTEM USES PHOTO-ACOUSTIC TECHNIQUE

By F.J. Wester, P. van den Aardweg, W.R. Rutgers and J. M. Wezter

1. INTRODUCTION

SF6 is an excellent insulation medium in circuit breaker installations and other HV power equipment. Because it is a greenhouse gas with a global warming potential that is 23,900 times higher than CO2, it must be handled with care. In the absence of an alternative, the energy sector may continue using this material under the condition that it is handled extremely carefully. In the near future, power utilities must keep records of the amount of SF6 that is lost.

During maintenance and dismantling of installations the gas must be recovered and returned to the supplier for recycling. Furthermore, after installation of new equipment it is necessary to check the gas tightness of the equipment. There is also a need for periodic inspection of installations filled with fluorinated gases, training and certification of personnel involved and improved reporting of inventories.

Included in the promise of 'best engineering practices' that the energy companies have made is the detection of leaks. Because no matter how well designed, in the course of time some gas can always escape through the seals, connections, supporting insulators and leadthroughs. Leakage of SF6 from gas-insulated installations is low, in the order of several per cent per year, but higher leakage may occur in faulty equipment.

As a result, detection of SF6 leakage is always necessary nowadays. This article discusses a new SF6 leakage detection method, with which SF6 leaks in gas-insulated and open substations can be located sensitively and while in-service.

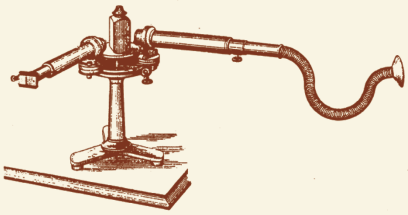

Figure 1 Principle of photo acoustic detection (Alexander Graham Bell). An absorbing material replaces the eyepiece of a spectroscope. The sound is detected with a receiver horn.

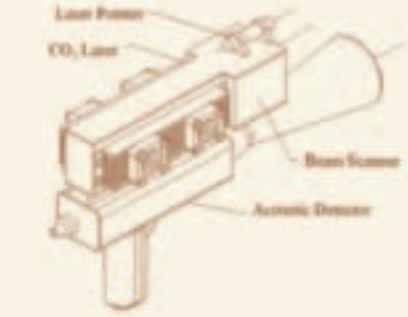

Figure 2 SF6 leakage detector, containing a laser to excite the SF6 and an acoustic detector to detect the signals coming from the excited SF6 gas. A laser pointer is used for aiming purposes.

2. SF6 DETECTION METHODS

How do you measure leakage in a high-voltage installation? Different methods for SF6 leakage detection are available for practical applications, varying from gas chromatography to laser cameras and acoustic methods. Leakage detection equipment is commercially available but not very practical in inspections of complete substations, as they use gas-suction to detect the gas. As a result, the gas detection apparatus should be held close to the HV equipment for good functionality, and therefore applied when the equipment is out of service. The commonly applied equipment can only measure at close proximity, so, in that case the installation must be taken out of service. For a high-voltage installation, this is a serious restriction.

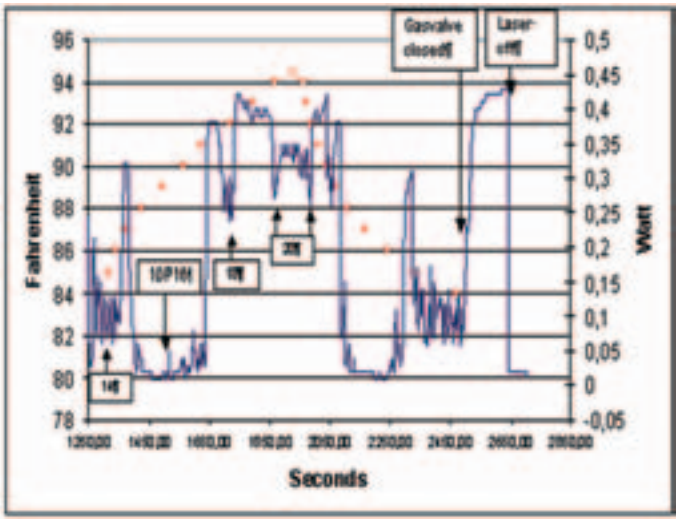

Figure 3 Laser beam power (blue) during heating and cooling of the laser (temperature in red) in the presence of a low concentration of SF6 gas between the laser and the detector (no scanners used)

It is true that for enclosed installations this is not necessary, but in that case the measurement equipment must still scan the installation little by little, which is a time consuming process. During in-service measurements, for safety reasons one must maintain a distance of five to ten meters from an open-air switching station to avoid coming into contact with high-voltage. In addition, the measurement equipment must be extremely sensitive, which means that the concentration of the escaping greenhouse gases must be measured in small values, usually in parts per million. One detection technique for on-line application is a laser based system (Gas Vue imaging system) that measures SF6 based on the absorption of laser light. If there is no reflecting surface behind the leak, as is often the case in open substations when measuring from the ground upwards, there is no signal.

A new on-line applicable SF6 leakage detection technique uses photo-acoustic detection of SF6. This system is highly sensitive and can be applied for leakage detection of gas insulated substations as well as gas-filled equipment in open substations. Because the distance to the object can be more than 5 meters, the leakage detection can be performed under service in open sub-stations. As the measurements can be performed from a safe distance to the equipment, leakages in the equipment can be located relatively fast.

3. PHOTO-ACOUSTIC DETECTION TECHNIQUE

Photo-acoustic detection is a well-developed technique for detection of small concentrations of many different gases in air, as is already applied for many years, shown in figure 1. It is

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SF6 leakage detection

Continued from Page 27

based on absorption of photons (usually from a pulsed laser as light source) and detection of acoustic signals due to gas expansion as the result of the gas heating. If detection is done in an absorption cell, the sensitivity can be very high: ppb concentrations can be measured for many gas molecules like SF6, NH3 or ethylene. For the on-line gas leakage detection in HV installations, the resulting acoustic signals are measured in the open air. This reduces the detection level to ppm concentrations, which is an acceptable sensitivity for leakage detection.

The developed SF6 leakage detector consists of a portable and battery operated CO2 laser, a beam scanner, an acoustic detector and a laser pointer (red light). The laser is temperature-controlled and tuned to the 10P16 transition at 10,55 µm wavelength which coincides with a strong absorption line of SF6 gas. At the beam scanner, the IR laser beam is spread with a resonant horizontal scanner at 4 kHz and a servo controlled vertical scanner at 200 Hz. In this way, a square gas detection surface is created of around 30 cm by 30 cm at a distance of 5 metres. The acoustic detector is operated at 30-40 kHz to avoid pick-up of background audio noise. As a result of the gas expansion of the SF6, a grumbling sound can be detected with the system. The laser pointer (red light) is used to pinpoint the centre of the IR beam on the object to be measured. The power supply of the laser and the temperature controller have been built in a trolley and connected by a cable with the leak detector.

Figure 4 Set up for beam profile measurements:
Right: temperature-controlled laser with beam scanners.

4. LABORATORY TESTS

The design parameters, performance and sensitivity of the photo-acoustic detector have been verified during laboratory tests.

4.1 IR absorption measurements

The absorption spectrum of SF6 contains many lines in the infrared due to vibrational and rotational excitation of the molecules. The strongest SF6 absorption line in the frequency band of the CO2 laser coincides with the 10P16 line (see figure 3) at a wavelength of 10.55 meter.

The laser can be tuned to different lines by changing the temperature of the cavity. Energy absorption of the gas was measured by measuring the laser power after the beam passed through a pipe with a low concentration SF6 gas.

When the laser temperature is increased or decreased (red dots in figure 3) the laser power is low for the different absorption lines. It is also clear that absorption for the 10P16 line is much higher than for the 10P14, 10P18 and 10P20 lines. Therefore the laser is set at a temperature of 88 Fahrenheit by a temperature controller, heating resistors and cooling fans.

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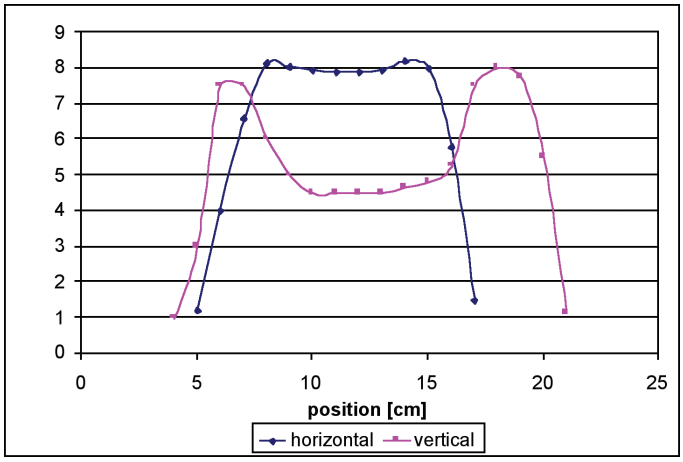

Figure 5 IR beam profile at a distance of 2.5 meter from the beam scanner

4.2 Beam profile measurements

The IR laser beam profile was measured with an IR detector (quantel type MP-310) in a set-up shown in figure 4. By scanning the detector in horizontal or vertical direction at a specific distance from this IR detector, the beam profile produced by the scanners is measured. Examples of measured beam profiles are given in figure 5 for the linear scanner and a resonant scanner. In these beam profiles (IR power), the difference of the scanner types is visible as the resonant scanner shows the highest power at its turning points. With this beam profile, it is shown that, at a distance of 2.5 meters, the scanning area of the SF6 leakage detector is around 15 by 15 cm. This means that during the in-service detection of SF6 filled equipment a suitable scanning area of 25 to 40 by 25 to 40 cm is used for the location of leakages, depending on the measuring distance from the objects.

5. ON-LINE MEASUREMENTS IN HV SUBSTATIONS

On-line measurements have been performed in different 150 kV open substations. During one of the measurements at an open substation, performed with a laser camera combined with an acoustic detector, a leaking gasket between the support insulator and circuit breaker was found in one of the circuit breakers under service. Another measurement in an open substation was performed with the photo-acoustic SF6 leakage detector and a conventional SF6 detector, the "SF6 Gascheck P1" of Ion Science. To make an optimal comparison between the two systems, a leaking-suspected circuit breaker in the station was taken out of service.

Figure 6 Leakage detection in a 150 kV open substation with the new leak detector

The measurements were started with the photo-acoustic detector, with which the following leaks were detected and pinpointed (measurements performed from a distance as if the circuit breaker was in service):

- a small leak at a link just above the filling location of the SF6;
- a leak at the base of one of the phases at that point where the driving mechanism enters the support insulator.

Next, the measurements are repeated with the conventional detection system, as this system enables quantification of the found leakage:

- the leak at the link just above the filling location showed an outcome of only 4 units (several ppm);
- the leak at the base of one of the phases at the entering of the driving mechanism showed an outcome of 50 units in the OUT-position and 85 units in the IN-position of the circuit breaker.

The comparison of measurement techniques illustrates the sensitivity of the photo-acoustic SF6 leakage detection method for on-line and off-line applications. Leakages of only several ppm of SF6 can be detected and located, while scanning the surfaces of gas-filled power equipment. The fact that the detection method is sufficiently sensitive in open-air circumstances shows that the method is also suitable for indoor situated gas-insulated switchgear.

MAKING ENERGY METERS THEFT-RESISTANT

By Paul Daigle

Only profitable businesses can offer high quality at an occasional discount. Utility companies are no different. All honest consumers of electricity would like everyone else that uses electricity to also pay for their fair share of electricity so that quality of distribution can improve. With the advent of electronic energy meters, utility companies have a wide selection of approaches to combat theft on their grid. The breadth of selection depends upon the available infrastructure and investment capital available.

The most robust and technically superior solution would approach the elusive goal of a tamper-proof meter. This elegant solution would monitor every energy meter remotely and capture an energy consumption reading every 15 or 30 minutes. Usage patterns could be monitored and abnormalities detected. A decision could be made to discontinue service remotely. Potential lost revenue from consumer misuse is eliminated quickly and the likelihood of corruption is curtailed significantly.

The success of an automatic meter reading solution relies on utility companies willing to take the risk of investing in a communications network and a data management infrastructure. The return on investment of such an installation project complicated by political agendas is difficult to justify before a real life testimonial can be used as an example. Based on risk and economic environment, utility companies in developing countries are forced to adopt a low cost approach instead of a technically superior solution.

Most of the electricity in developing countries is distributed on two-wire, single phase. The functional equivalent to the electromechanical meter is an electronic energy meter that measures current in the phase wire. An example of the typical connection on a standard electronic energy meter used for two-wire, single-phase distribution is shown in figure 1. This configuration, installed by utility companies, allows correct billing by monitoring current only in the phase wire but this is not sufficient to bill correctly under popular tampering schemes.

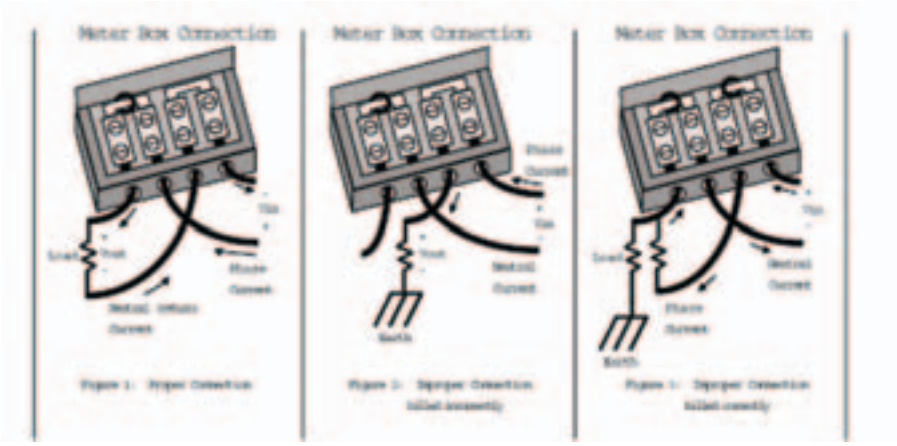

Figure 1 Figure 2 Figure 3

This example uses a current transformer as the transducer on the phase current path.

A popular approach to designing a tamper-resistant energy meter monitors current in both the phase and return path. Monitoring both phase and neutral and calculating real average power based on the larger of the two currents eliminates most pilfering schemes that tamper with the current path through the energy meter. A mechanical meter or an electronic meter with a single current transducer is unable to detect power consumption of the load in the configuration shown in figure 2. Figure 2 illustrates blatant tampering that is easy to detect with visual inspection. Figure 3 illustrates a more subtle approach. All connections to the meter are correct but not all of the current supplied to the load is returned through the meter.

A popular tactic that is difficult to detect is to reduce the size of one's bill by creating a partial earth fault. This illustration uses two current transformers that are fairly well matched to eliminate the need for calibration of the second current channel. The meter bills according to the larger of the phase or neutral currents.

These types of simple tampering schemes can cost power generation and distribution companies lots of money when implemented on high current loads. The cost for implementing a meter capable of reliably detecting differences in phase and neutral currents at very low currents is probably unwarranted. Electronic energy meter manufacturers have been designing these systems with multiple integrated circuits. The multiplexers and comparators used in these schemes increase component count and are not able to bill accurately under a fault condition. For example, the AD7751 integrates this functionality onto a single chip to eliminate switching and threshold noise while reducing component count. A fault is indicated when the phase and neutral currents differ by more than 12.5%. Billing is continued using the larger of the two currents. The lowest cost meter still requires manual reading of a mechanical counter.

The AD7751 drives the stepper motor counter directly to facilitate the lowest cost design.

Paul Daigle is the Product Manager for the energy measurement group of Analog Devices, Inc. in Wilmington, MA. He holds an MSEE and a BSEE from Syracuse University.

NEW TRANSMISSION LINE SITING APPROACH WINS INNOVATORS' AWARD

Dr. Joseph Berry, principal of Berry and Associates, Spatial Information Systems (BASIS), leads a workshop with stakeholders. These workshops are integral to the EPRI-GTC siting methodology process.

Georgia Transmission Corporation has been selected as a winner of a 2006 Cooperative Innovators Award by the Cooperative Research Network (CRN) of the National Rural Electric Cooperative Association (NRECA). Georgia Transmission was honored for a new approach to siting transmission power lines that the company developed with the Electric Power Research Institute (EPRI).

The award, presented at NRECA's Connect conference in San Antonio, is given each year by the association's Cooperative Research Network to electric cooperatives that pioneer new technologies to enhance customer service. Georgia Transmission Corp. (GTC) is a not-for-profit electric cooperative that builds and maintains electric transmission lines and substations for 39 electric membership cooperatives throughout the state. Electric transmission lines are high-voltage lines that transmit power from plants and other generators to local utilities that distribute it to customers over neighborhood distribution lines.

"We are honored to win this award," said Mike Smith, Georgia Transmission's CEO. "We are especially gratified since the award will increase awareness of this important new tool. This gives planners and engineers new freedom to exercise their expert siting judgment by making it easier to manage multiple decisions and sets of geographic data. We feel that electric utilities would benefit enormously from this standardized siting process."

The new transmission line siting approach was created during a two-year research effort spearheaded by GTC and jointly funded with the Electric Power Research Institute (EPRI), Palo Alto, Calif., and Photo Science, Lexington, Ky. In February, EPRI released the results of that research to the electric industry in the EPRI-GTC Overhead Transmission Line Siting Methodology. The report presents the new industry standard for siting overhead transmission lines by taking a sample transmission line construction project from initial planning through final route selection. Judges for the Cooperative Innovators Award recognized GTC's siting approach for its:

- Rigorous, step-by-step procedures for documenting and consistently applying planning assumptions, evaluation criteria and decisions;
- Successful integration of GIS software, including the use of suitability surfaces for natural, engineering and man-made conditions – a novel step that has potential application for GIS work on other linear utility siting;
- Achieving stakeholder consensus on the methodology and siting criteria during workshops with more than 200 officials from government agencies, utilities, environmental groups and neighborhood organizations from Georgia and neighboring states; and
- Demonstrated productivity and cost savings on GTC's siting of several hundred miles of transmission lines, adoption

Continued on Page 32

line siting approach

Continued from Page 31

of the process by East Kentucky Power Cooperative and other significant industry recognition.

The GTC-EPRI siting study team included national experts in geographic information systems (GIS) technology, facility siting and environmental compliance. Using GIS software called Corridor Analyst®, the methodology helps to produce siting decisions that are consistent, objective and defensible. The software maps all geographic features in a study area, assigns numerical suitability values to all features, enables public stakeholders to help set suitability values, assigns engineering constraints, generates corridor alternatives using statistically sound algorithms and generates reports summarizing criteria used and values assigned.

Members of the development team from Georgia Transmission Corporation (GTC) and Photo Science discuss the EPRI-GTC Transmission Line Siting Methodology. They are (L-R) Jesse Glasgow, Photo Science; Gayle Houston, GTC; Christy Johnson, GTC; and Chris Smith, Photo Science. Preeminent scientists and statisticians and more than 200 participants from government agencies, utilities, environmental groups and neighborhood organizations took part in the research and development.

"The judges were particularly impressed by GTC's entry," said Bob Gibson of the Cooperative Research Network. "They recognized the high value of a scientific and quantifiable approach to siting power lines, one that promises to effectively involve stakeholders and streamline an increasingly difficult process."

The CRN awards program is open to all 900 consumer-owned electric cooperatives in the United States. GTC's award was in the power generation and transmission category.

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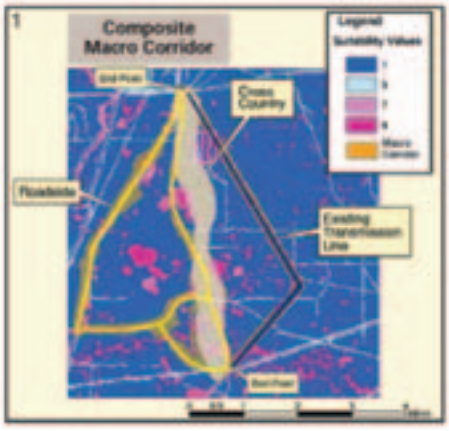
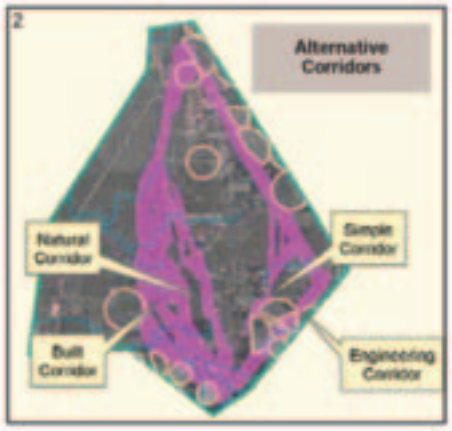
Just what exactly is the "siting methodology"? Although the answer takes more than 200 pages to explain in the GTC-EPRI siting report, we try below to explain the two years of work in a few paragraphs.

Here are the significant actions that take place during each major phase of the GTC-EPRI transmission line siting process.





STEP 1: IDENTIFY MACRO CORRIDORS

System Planning provides beginning and end points where a new power line is needed. From there, satellite imagery and data on roads, slopes and existing transmission lines are merged to form one

digital map. This composite map is comprised of a grid of 30-square meter cells.

• Areas of highest environmental and cultural sensitivity are removed from consideration.

• Each cell on the map is ranked.

Features like open water, agriculture and wetlands are ranked from 1 (most suitable) to 9 (least suitable). Using the cell values, a computer algorithm calculates optimal paths for three types of suitability surfaces: locating with existing transmission lines, locating with existing road rights of way and crossing less developed areas.

The optimal paths identified are called macro corridors. Combined, the outer boundaries of the macro corridors define the study area limits.

STEP 2: IDENTIFY ALTERNATIVE CORRIDORS

More detailed project data and geographic data, including one-foot aerial photography, are collected and used to identify alternative corridors within the macro corridors. Three types of alternative corridors are defined:

• Built environment: protecting human and cultural resource areas

• Natural environment: protecting plants, animals and aquatic resources, and

• Engineering requirements: minimizing cost and schedule challenges.

COLLABORATIVE RANKINGS

To make the process more objective, the GTC-EPRI team and external stakeholders set evaluation criteria and rank factors, such as housing density, wetlands and land cover. More than 400 stakeholders from government, industry and civic groups took part, evaluating the siting process, establishing feature rankings and weighting data layers.

STEP 3: IDENTIFY ALTERNATIVE ROUTES

In this phase, potential routes are determined. Sets of very detailed data are collected and used with the GIS-based Siting Model software suite.

• At this point, property lines are identified and buildings that were digitized earlier in the process are classified by types, such as occupied house, commercial building or industrial building.

This one change to GTC's siting practice – acquiring detailed datasets after alternative corridors are identified — significantly lowers GTC's data collection costs.

STEP 4: SELECTING A PREFERRED ROUTE

Siting team members rank each alternative route and used data to select a preferred route.

• Siting team members assign ranks and weights to community concerns, visual concerns, special permit issues, scheduling delay risks and construction and maintenance accessibility.

• Ranks and weights are calculated for each alternative and the siting team ranks each alternative route.

At this point, the GIS-based siting model becomes a productivity tool to aid the decision-making. The siting team from engineering, land acquisition, environmental and other areas can use map overlays, spreadsheets, reports and graphic illustrations to examine and modify all aspects of the route selection.

Obituary:

Kenneth Lay 1942-2006

KEN LAY'S TOP 10 LIFE LESSONS LEARNED

1. Cheaters never prosper
2. Crime doesn't pay
3. What goes around, comes around
4. Ignorance is no defence
5. Don't place too much trust in experts
6. It's not good to operate on credit
7. Any surplus is immoral
8. Private property creates crime
9. A sense of timing is the mark of genius
10. You have to hurt others to be extraordinary

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MAKING THE SWITCH TO SOY FROM PETROLEUM-BASED COOLANT

United Rural Electric Membership Cooperative (REMC), electrical provider to approximately 10,000 customers in a seven-county area in Northeast Indiana, is the state's first utility to use a substation with a fire-resistant, biodegradable, vegetable-based coolant.

The utility is installing a new substation with a safer soy-based product, eliminating the need for a hazardous petroleum-based coolant. Approximately 3,000 gallons of soy-based fluid will be used to serve an industrial park that provides power to several new housing developments and numerous local businesses, including the new corporate center for handbag and accessory designer, Vera Bradley.

The Envirotemp FR3 transformer fluid is made from soybeans, one of the largest agricultural cash crops in the United States. In addition to public safety and environmental benefits, United REMC's switch to Envirotemp FR3 fluid reduces the dependency on imported petroleum, while supporting soybean farmers in Indiana, one of the nation's leading soy-producing states.

Petroleum-based fluids are flammable at 311 degrees Fahrenheit, costlier to clean up in the case of spills, harmful to the environment and contain known carcinogens. FR3 fluid has the highest flash (626 F) and fire (680 F) points of any fluid currently on the market.

"Cooper Power System's FR3 fluid will not only positively impact our electrical system and utility business, but the environment all around us," said John Klingenberger, corporate relations manager, United REMC. "The added safety benefits will bring ease to our workers and the public at large."

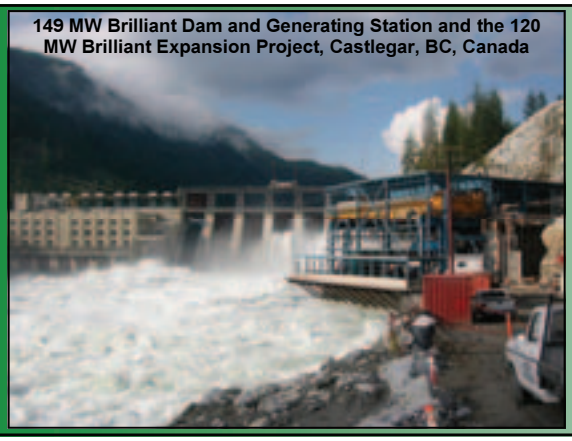
In the early 1990s, Cooper Power Systems began the development of a vegetable-based transformer oil. In 2004, it partnered with Cargill Inc. to produce and distribute Envirotemp FR3 fluid that was designed to enhance transformer performance, increase worker and improve environmental safety, all essentially lowering costs for utilities. Due to its very high fire-ignition temperature, no transformers with FR3 fluid have caught fire.

Envirotemp FR3 fluid received the U.S. Environmental Protection Agency's Environmental Technologies Verification, confirming its environmental attributes. In addition, Envirotemp FR3 fluid has shown to be non-toxic, and has the highest EPA classification for biodegradability. Because the fluid also has excellent fire-resistant qualities, Underwriters Laboratories (UL) and Factory Mutual (FM) allow Envirotemp FR3 transformer installations outdoors and indoors, typically without costly fire protection and insurance devices required of petroleum-filled transformers.

Indiana's Lieutenant Governor, Becky Skillman; United REMC, Ted Martz; and Ron Chapman, Cooper Power Systems, stand in front of the new substation.

More than 15,000 new and retrofilled transformers in more than 70 municipal and rural electric cooperatives are using Envirotemp FR3 fluid today. Utilities including Alabama Power, Baltimore Gas & Electric, Monroe County (St. Louis, Mo.), Sacramento Municipal Utility District, and Seattle City Light are using soy-based transformer fluids on their systems.

149 MW Brilliant Dam and Generating Station and the 120 MW Brilliant Expansion Project, Castlegar, BC, Canada



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