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North American Policies and Technologies

Electricity Transmission & Distribution Today

The Electricity Forum

September 2007
Volume 19, No. 7

AMR Deployment Stories

Various utilities share their experiences

Page 8

and

The State of Ontario's Smart Metering Initiative

Page 22

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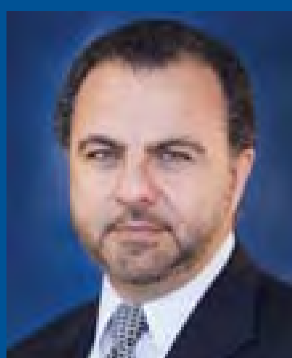

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DAVID O'BRIEN, President and Chief Executive Officer, Toronto Hydro

David O'Brien is the President and Chief Executive Officer of Toronto Hydro Corporation. In 2005, Mr. O'Brien was the recipient of the Ontario Energy Association (OEA) Leader of the Year Award, establishing him as one of the most influential leaders in the Ontario electricity industry. Mr. O'Brien is the Chair of the OEA, a Board Member of the EDA and a Board Member of OMERS.

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Mr. Macaluso has more than 20 years experience in the electricity industry. As the CEO of the EDA, Mr. Macaluso spearheaded the reform of the EDA to meet the emerging competitive electricity marketplace, and positioned the EDA as the voice of Ontario's local electricity distributors, the publicly and privately owned companies that safely and reliably deliver electricity to over four million Ontario homes, businesses, and public institutions.

SCOTT ROUSE, Managing Partner, Energy @ Work

Scott Rouse is a strong advocate for proactive energy solutions. He has achieved North American recognition for developing an energy efficiency program that won Canadian and US EPA Climate Protection Awards through practical and proven solutions. As a published author, Scott has been called to be a keynote speaker across the continent for numerous organizations including the ACEEE, IEEE, EPRI, and Combustion Canada. Scott is a founding chair of Canada's Energy Manager network and is a professional engineer, holds an M.B.A. and is also a Certified Energy Manager.

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David W. Moncur has 29 years of electrical maintenance experience ranging from high voltage installations to CNC computer applications, and has conducted an analysis of more than 60,000 various electrical failures involving all types and manner of equipment. Mr. Moncur has chaired a Canadian Standards Association committee and the EASA Ontario Chapter CSA Liaison Committee, and is a Past President of the Windsor Construction Association.

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MANY STILL MISUNDERSTANDING GORE'S MESSAGE

Randy Hurst, Publisher

Gore Electricity seems to be receiving the attention of everyone these days - but mostly negative attention from political opponents and righteous environmentalists. The fact that former vice president and global warming solutions advocate Al Gore uses twenty times more electricity in one year than the average American, says exactly what?

According to the Nashville Electricity Service, Al Gore's 20-room, 8-bathroom, 10,000 square foot home "devoured" nearly 221,000 kWh per year, more than 20 times the national household average. Gore's electricity monthly bill topped $1,359.

If you listen to groups like the Tennessee Center for Policy Research, you will hear that while Al Gore's global-warming documentary, An Inconvenient Truth, collected an Oscar for best documentary feature, maybe he deserves a gold statue for hypocrisy.

It's always easy to call someone long on talk and short on walk but the truth is that Gore electricity is actually "green electricity". The Gore electricity bill shows that he voluntarily pays the higher cost for something called "Green Power Switch", which uses more expensive energy from renewable sources like wind and solar power. How does this work?

Many energy companies are now offering consumers the opportunity to purchase electricity from green energy sources. These green energy sources include wind energy, hydro energy, biomass, solar energy and will begin to include marine energy sources such as wave power, tidal stream and tidal impoundments and tidal barrages.

This separation of renewable energy from oil, gas, coal and nuclear is possible due to the Renewable Energy certificate schemes now being developed worldwide. These certificates enable units of electricity, such as KWh to be identified as soon as they are produced and fed into the national grid. All units must be accounted for both in terms of how and when they were produced and who sold them to whom. Theoretically, this means consumers can “buy” units from specific turbines. In reality, the actual electrons running through a consumer’s meter will not be generated by any source in particular, as all electricity (for the most part) - however it has been generated - is fed into the national grid. Buying green electricity in this manner means that you are buying up a certain “tokens” that acknowledge that every unit you have used has been made up for from a renewable source.

When you switch to an accredited "Green" electricity provider, you're instructing them to purchase your nominated percentage of electricity from new renewable sources, rather than coal-fired power stations. You still receive your electricity in the normal way, but every kilowatt hour of the nominated percentage of Green Electricity you purchased will be supplied into the grid from a renewable source.

Gore also purchases offsets for carbon fuel use. So, technically, Gore electricity is probably carbon neutral, because for every bit of CO^2 he puts into the air, a forest is built with his money to sequester that same CO^2. Does he drive an SUV? Of course, but it's a hybrid SUV.

Gore electricity consumption proves what? He has done twenty times more for the environmental movement than the average American. His contribution to the exchange of information about Global Warming has been much more than the average American. The truth is that the average American is not a former vice president, and the average American does not reside in a 20-room mansion, has no domestic staff, does not have an extensive security system with perimeter lighting, does not have extensive computer and communications requirements, not to speak of HVAC duties, etc. Yes, Al Gore lives a life of privilege and luxury, as do most millionaires. If you honestly expect a wealthy politician, no matter how well-intentioned, to live life like a serf, you are badly misguided about the modern world. Would honest Abe Lincoln (had he lived to see the day) have moved from the White House back to the log cabin from whence he came? Will the world devolve from its addiction to technology and modernism, only to embrace the stone age?

Instead of the whole world environmental initiative being about returning everyone to the stone age, maybe it could be about turning our future world into a bigger and better place, with less harm to the environment, being a more populated and prosperous world without fossil fuels. Isn't that what Gore Electricity is all about: using more of the "right kind" of electricity? Or is Gore Electricity really about who has what and who doesn't and who shouldn't?

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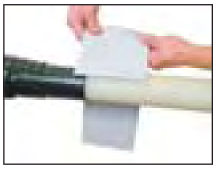

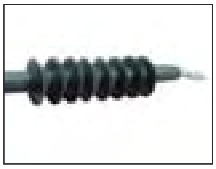

3M

UTILITIES SHARE THEIR VARIOUS AMR DEPLOYMENT STORIES

PPL ELECTRIC UTILITIES

Late in 2004, PPL Electric Utilities completed an AMR deployment to all of its 1.35 million customers. At PPL Electric, we deployed a fixed network PLC system for the majority of customers, supplemented with a fixed network radio frequency solution to about 6,000 customers.

It was a highly successful project - on time, on budget - and afforded positive regulatory treatment. The type of risks often associated with large projects failed to materialize, and the technology is performing at or above expectations, meeting the requirements of the business case.

In fact, compared with many other high-risk projects such as customer or financial system deployment, an AMR project is relatively easy to deploy. In retrospect, one wonders why there is so much angst in the electric utility industry over deploying AMR solutions.

While all the above certainly is good news, the real insight to deployment is not so much the project's success but rather the versatility of the solution. The new tool, as expected, has virtually eliminated estimated bills by automating the meter-reading processes, and has improved other business processes through the ability to constantly communicate with the meter. What was unexpected is how business embraced the tool and applied it in new, creative applications.

In the fall of 2003, a major tropical storm wreaked havoc in the PPL Electric service area, interrupting service to more than 40% of customers. Even with a partially deployed system, storm managers recognized the benefit of two-way communication with the meter in assessing restoration progress.

A completely new storm restoration tool was subsequently developed incorporating the "ping" capability.

In another unanticipated use, field engineers are geared up to use information on momentary outages - "blink" counts - as reliability predictors. Using this data has resulted in more precisely focused tree trimming efforts, improved analysis of individual customer power quality problems and, ultimately, higher customer satisfaction. It is interesting to consider that with a manual meter-reading process, the customer "communicated" with the utility about 12 times a year.

With the ability to get hourly reads, customers now can communicate with the company almost 9,000 times a year. The increased granularity of this information provides some unique opportunities. The company's customer service representatives, armed with easily accessible data on daily or even hourly usage, approach high-bill complaints with greater levels of confidence.

Having this information has improved credibility with customers.

One result has been fewer complaints to the regulators over handling of customer billing disputes. The AMR system allows customer call center reps to more effectively address customer complaints regarding issues such as high bills, connects/disconnects and estimated meter readings. AMR is particularly helpful in addressing high-bill complaints.

Continued on Page 10

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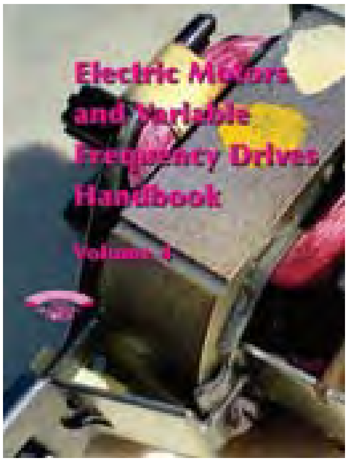

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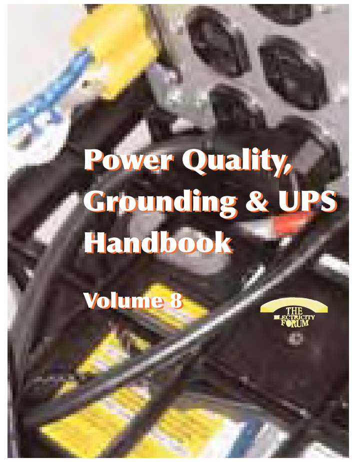

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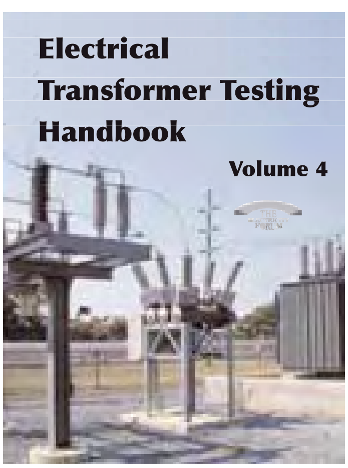

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AMR deployment

Continued on Page 8

For example, the number of high-bill informal complaints received by PPL Electric decreased from 525 in 2003 to 273 in 2004 - a drop of 48%. Similarly, the number of justified high-bill informal complaints for the same period declined from 92 to 11 - a decrease of 88%.

Revenue protection staff anticipates that usage irregularities will be easier to identify and will result in more solid theft leads. The system's operation is even helping to "clean up" the electric system.

AMR system operators will dispatch service personnel to locations where meters are not communicating. In many instances, the source of the failure is not inoperable metering equipment, but interference associated with problems in the electric service - i.e., bad neutral. In a similar vein, the company is able to better align customer usage with rates. With a new metering infrastructure, it is able to bill demand customers appropriately, resulting in an additional $3 million in annual revenues.

Pennsylvania is a progressive state in terms of utility deregulation, offering customers competitive alternatives, such as demand side response programs and the use of distributed generation and renewable technologies. In selecting a technology, it was important for the utility to try to anticipate the ease or difficulty in adapting it to meet future needs in these areas. Two-way communication at the meter and the ability to obtain interval reads provide that flexibility.

Deploying an AMR solution for all customers can be a daunting task. Developing an acceptable business case, managing risks and maintaining schedules are significant undertakings. Yet companies that deploy these solutions will find great improvement in almost every important business dimension - fiscally, operationally and in customer satisfaction.

PENINSULA LIGHT CO.

Peninsula Light Company (PLC) has just installed an Automated Meter Reading system. The new system sends data from each meter back to the office over existing power lines. AMR technology allows us to offer a number of helpful benefits for PLC members... like greater consistency in billing and the ability for PLC to provide members with more detailed information about their power consumption. Should a member's power go out, the automated meters help PLC operations pinpoint the cause of the outage and accelerate response time.

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By deploying AMR technology, PLC has been able to provide members with more frequent, timely and accurate electric meter readings without the need for meter readers to go to the customer's property. As a result, the need for estimated bills will be virtually eliminated, leading to greater accuracy on the consumer's monthly bill. Another benefit of AMR to PLC customers is a more accurate and efficient way to monitor reported outages.

CLARK PUBLIC UTILITIES

Itron, Inc. (ITRI) signed a contract with Clark Public Utilities, electricity supplier to more than 150,000 customers in southwest Washington State, providing the utility with technology to automate meter data collection throughout its service territory.

Clark Public Utilities is a customer-owned public utility district that provides electric service to more than 150,000 customers throughout Clark County in Southwest Washington State. The utility also provides water and wastewater service.

Clark Public Utilities

Installation of the $10 million meter reading system, the largest AMR deployment to date by a consumer-owned electric utility in the U.S., was completed in the fall of 2002. Clark Public Utilities now uses vehicles equipped with on-board Itron computers and RF transceivers to automatically collect data from all of the utility's 150,000 electric meters simply by driving down the street.

Because Itron's AMR meter modules can be read by any of Itron's wireless data collection systems, the system also enables the Vancouver, Wash.-based utility to "migrate" to advanced fixed network technology in the future without having to replace installed meter modules should Clark's data collection needs change.

"At Clark Public Utilities we're committed to continually improve our operational efficiency so that we can keep our rates

Continued on Page 12

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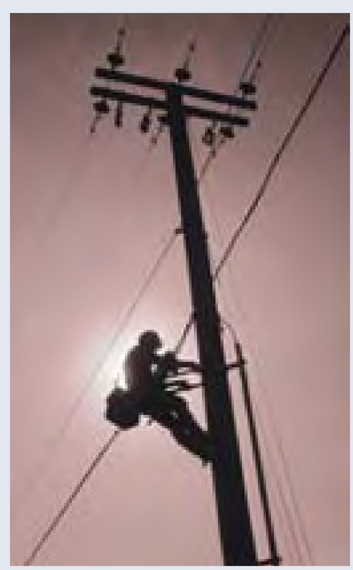

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AMR deployment
Continued on Page 10

as low as possible, and we're committed to achieving the highest level of satisfaction among our customer-owners," said Wayne Nelson, CEO and general manager of Clark Public Utilities.

"Implementation of automatic meter reading technology from Itron will be a key step in fulfilling both of these vital commitments in the years to come."

Clark's decision to deploy automatic meter reading technology, which was approved by the utility's board of commissioners, came at a time when the utility faced considerable budgetary pressure due to dramatic increases in wholesale electricity prices, said Richard Dyer, director of finance and treasurer at Clark. However, the efficiency gains, the relatively quick projected payback schedule, and the strategic value of AMR technology made it a very sound investment for the utility and its customer-owners.

"Like many other utilities, we've faced sky-high wholesale energy prices, but we believe the capabilities and data this technology provides will prove critical to minimizing risk in today's highly volatile energy market," said Dyer. "Now is not the time to shy away from innovation and technologies that reduce our costs and improve the way we operate as a business."

Clark's three-member board of commissioners echoed that opinion when it unanimously approved the AMR project. "It's easy when you are in a crisis to hunker down and miss opportunities," Clark Public Utilities Commissioner Nancy Barnes commented before casting her vote in support of the project.

"When you consider the financial pressures utilities are facing today due to increasing energy prices, it would have been very easy for Clark to put this investment on the shelf until energy prices stabilize," said John Hengesh, vice president and general manager of Itron's Water and Public Power business unit. "But Clark Public Utilities sees AMR technology as a strategic investment that reduces costs, increases operational efficiency and delivers reliable, accurate knowledge about its customers' energy consumption. In today's volatile market environment, these benefits and capabilities are more critical to utilities than ever before."

Colorado Springs Utilities
It's how we're all connected

COLORADO SPRINGS UTILITIES

Colorado Springs Utilities is deploying an automated meter reading (AMR) program, with full deployment taking place from late 2006 through 2010. Using wireless radio transmitters, AMR remotely reads customer meters and then transfers the data into the billing system. AMR will reduce the need for meter readers to manually gather utility meter readings each month. Many utilities are using AMR as a way to improve customer service and control their meter reading costs, especially in areas with fenced yards, dogs, landscaping and other issues that make accessing meters difficult or unsafe. Benefits include:

Improved customer service, which includes:

· Minimizing the need to access customer property to read meters;

· Reducing customer complaints and damage claims resulting from monthly visits to customer site;

· Call resolution improvement – billing complaint calls will be handled more quickly due to availability of more frequent meter readings;

· No need for customer to read their own meters due to meter access issues;

· Controlled meter reading costs;

· Enhanced customer convenience;

· Fewer employee injuries, especially in areas with fenced yards, dogs and landscaping;

· Improved billing accuracy;

· A reduction in operational costs.

EQUITABLE GAS COMPANY

Itron Inc. has announced a new contract with Equitable Gas Company, headquartered in Pittsburgh, to install a mobile automatic meter reading system throughout Equitable's service territory.

The deployment includes the installation of 260,000 Itron radio-based automatic meter-reading endpoints on Equitable's natural gas meters as well as delivery of the mobile data collection equipment and associated software. Itron's mobile automatic meter reading technology will enable Equitable Gas to reduce its meter reading process costs while enabling the utility's service technicians to use their time more efficiently.

"We're deploying Itron's automatic meter reading technology as part of our ongoing efforts to improve customer service and reduce our costs," said Randall Crawford, president of Equitable Gas Company.

"The use of Itron's technology will also improve our relationship with more than 60,000 customers who currently have indoor meter sets, as the automatic meter reading technology virtually eliminates the need to disrupt our customers' daily schedules to read their meters.

"We will dramatically reduce the need to estimate meter reads which will improve our billing accuracy and ultimately work to reduce operating costs across our system."

Russ Vanos, vice president and general manager of Itron's hardware solutions group, said Equitable Gas was seeking a cost-effective meter data collection solution with proven results, and that Itron's mobile automatic meter reading technology was the best fit to meet Equitable's business objectives.

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POWER TRANSMISSION CAPACITY UPGRADE OF OVERHEAD LINES - PART II

By D.M. Larruskain, I. Zamora, O. Abarrategui, A. Iraolagoitia, M. D. Gutiérrez, E. Loroño and F. de la Bodega, Department of Electrical Engineering, E.U.I.T.I., University of the Basque Country

DC VERSUS AC

The vast majority of electric power transmissions use three-phase alternating current. The reasons behind a choice of HVDC instead of AC to transmit power in a specific case are often numerous and complex. Each individual transmission project will display its own set of reasons justifying the choice.

General characteristics

The most common arguments favouring HVDC are:

1) Investment cost. A HVDC transmission line costs less than an AC line for the same transmission capacity. However, the terminal stations are more expensive in the HVDC case due to the fact that they must perform the conversion from AC to DC and vice versa. On the other hand, the costs of transmission medium (overhead lines and cables), land acquisition/right-of-way costs are lower in the HVDC case. Moreover, the operation and maintenance costs are lower in the HVDC case. Initial loss levels are higher in the HVDC system, but they do not vary with distance. In contrast, loss levels increase with distance in a high voltage AC system

Above a certain distance, the so called “break-even distance”, the HVDC alternative will always give the lowest cost. The break-even-distance is much smaller for submarine cables (typically about 50 km) than for an overhead line transmission. The distance depends on several factors, as transmission medium, different local aspects (permits, cost of local labour etc.) and an analysis must be made for each individual case (Fig. 3).

2) Long distance water crossing. In a long AC cable transmission, the reactive power flow due to the large cable capacitance will limit the maximum transmission distance. With HVDC there is no such limitation, so, for long cable links, HVDC is the only viable technical alternative.

3) Lower losses. An optimized HVDC transmission line has lower losses than AC lines for the same power capacity. The losses in the converter stations have, of course, to be added, but since they are only about 0.6% of the transmitted power in each station, the total HVDC transmission losses come out lower than the AC losses in practically all cases. HVDC cables also have lower losses than AC cables.

4) Asynchronous connection. It is sometimes difficult or impossible to connect two AC networks for stability reasons. In such cases, HVDC is the only way to make an exchange of power between the two networks possible. There are also HVDC links between networks with different nominal frequencies (50 and 60 Hz) in Japan and South America.

5) Controllability. One of the fundamental advantages with HVDC is that it is very easy to control the active power in the link.

6) Limit short circuit currents. A HVDC transmission does not contribute to the short circuit current of the interconnected AC system.

7) Environment. Improved energy transmission possibilities contribute to a more efficient utilization of existing power plants. The land coverage and the associated right-of-way cost for a HVDC overhead transmission line is not as high as for an AC line. This reduces the visual impact.

It is also possible to increase the power transmission capacity for existing rights of way. There are, however, some environmental issues that must be considered for converter stations, such as: audible noise, visual impact, electromagnetic compatibility and use of ground or sea return path in monopolar operation.

In general, it can be said that a HVDC system is highly compatible with any environment and can be integrated into it without the need to compromise on any environmentally important issues of today.

POWER CARRYING CAPABILITY OF AC AND DC LINES

It is difficult to compare transmission capacity of AC lines and DC lines. For AC the actual transmission capacity is a function of reactive power requirements and security of operation (stability). For DC, it depends mainly on the thermal constraints of the line.

If, for a given insulation length, the ratio of continuous-working withstand voltage is as indicated in equation (1).

$$k = \frac{DC \cdot withs\tan d \cdot voltage}{AC \cdot withs\tan d \cdot voltage(rms)} \qquad (1)$$

Various experiments on outdoor DC overhead-line insulators have demonstrated that due to unfavourable effects, there is some precipitation of pollution on one end of the insulators and a safe factor under such conditions is k=1. However if an overhead line is passing through a reasonably clean area, k may be as high as √2, corresponding to the peak value of rms alternating voltage. For cables, however, k equals at last 2.

A line has to be insulated for overvoltages expected during faults, switching operations, etc. AC transmission lines are normally insulated against overvoltages of more than 4 times the normal rms voltage; this insulation requirement can be met by insulation corresponding to an AC voltage of 2.5 to 3 times the normal rated voltage.

$$k_1 = \frac{AC \cdot insulation \cdot level}{rated \cdot AC \cdot voltage(E_p)} = 2.5 \qquad (2)$$

On the other hand, with suitable conversor control, the corresponding HVDC transmission ratio is shown in equation (3).

$$k_2 = \frac{DC \cdot insulation \cdot level}{rated \cdot DC \cdot voltage(V_p)} = 1.7 \qquad (3)$$

Thus, for a DC pole-to-earth voltage

Vd and AC phase-to-earth voltage Ep the relations (4) exist.

$$Insulation \cdot ratio = \frac{insulation \cdot length \cdot required \cdot for \cdot each \cdot AC \cdot phase}{insulation \cdot length \cdot required \cdot for \cdot each \cdot DC \cdot pole} \quad (4)$$

and substituting (1), (2) and (3) equations, we obtain equation (5) for the insulation ratio.

$$Insulation \cdot ratio = \left(k \frac{k_1}{k_2}\right) \frac{E_p}{V_d} \quad (5)$$

DC transmission capacity of an existing three-phase double circuit AC line: the AC line can be converted to three DC circuits, each having two conductors at ± Vd to earth respectively.

Power transmitted by AC:

$$P_a = 6E_p I_L \quad (6)$$

Power transmitted by DC:

$$P_d = 6V_d I_d \quad (7)$$

On the basis of equal current and insulation

$$I_L = I_d \quad (8)$$

$$V_d = \left(k \frac{k_1}{k_2}\right) E_p \quad (9)$$

The following relation shows the power ratio.

$$\frac{P_d}{P_a} = \frac{V_d}{E_p}\left(k \frac{k_1}{k_2}\right) \quad (10)$$

For the same values of k, k1 and k2 as above, the power transmitted by overhead lines can be increased to 147%, with the percentage line losses reduced to 68% and corresponding figures for cables are 294% and 34% respectively.

Besides, if the AC line is converted, a more substantial power upgrading is possible. There are several conversions of AC lines to DC lines proposals, these conversions are carried out as a simple reconstruction. The most feasible of them is Double Circuit AC Conversion to Bipolar DC. It implies tower modifications that maintain all the conductors at a height above ground of 1 to 2 meters below the original position of the lowest conductor during the whole construction phase. Two new crossarms are inserted at the level of the old intermediate crossarm.

No change is made to the conductors, the total rated current remains the same, which means that the transmitted power increases proportionally to the adopted new DC line-to-ground voltage. The conversion of lines where an increase of phase-to-ground voltage can be higher than 3 is possible when all the conductors of one AC circuit are concentrated in one DC pole.

The line-to-line (LL) AC voltage is doubled for use with DC, thus the transmitted power will increase by 3.5 times.

CONCLUSIONS

Given the many changes in the way the power transmission system is being planned and operated, there is a need to reach higher current densities in existing transmission lines.

The different types of constraints that limit power transfer capability of the transmission system are discussed for analyzing the upgrade possibilities to increase the transmission capacity.

GIVING NEW LIFE TO CABLE UNDERGROUND

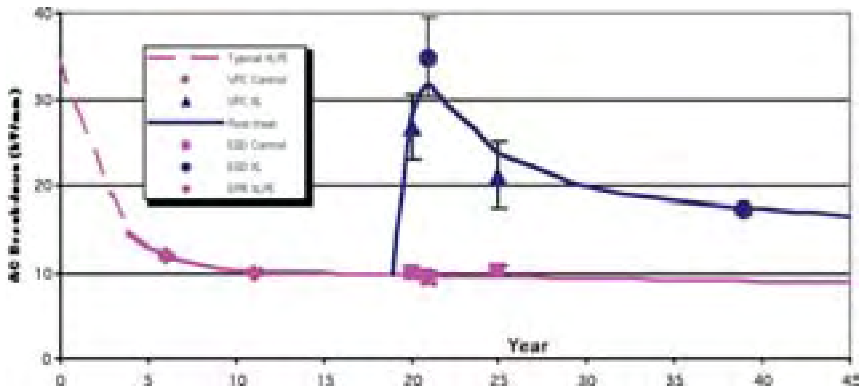


Figure 1. Typical performance of pre-1980 vintage PE cables and typical post injection performance.

For decades, utilities have used polyethylene-insulated cables for construction of underground electrical distribution and transmission lines. The high proliferation of these types of cables is justified by their low cost, high availability and ease of installation. Improvements to the quality of the raw materials as well as better manufacturing techniques have increased the life expectancy of these insulated conductors.

Earlier vintages (pre-1980) have experienced a higher than expected failure rate. Some of these failures are the consequence of inappropriate installation, dig-ins, power surges or other operating related incidents, but the degradation of the polyethylene insulation used in most of these cables is by far, the single most important source of cable faults. This premature aging process is caused by water treeing.

Water trees start with imperfections (surface irregularities, voids, contaminants, etc.) in the cable insulation. They grow in all solid dielectric materials in the presence of high AC stress (caused by imperfections) and water. These tree shaped structures are diffuse clouds of microscopic unconnected micro-voids. They are conductive in presence of water (water that can contain conductive particles or ions) and can be dielectric when dry. The presence of water in water trees can facilitate the initiation of electric trees. Water trees reduce the AC break down (ACBD) strength of polyethylene-insulated cables. In time the electrical stress exceeds the ACBD and water trees evolve into electric trees.

This final state of degradation is irreversible and cable failure is imminent. A fault will occur in a short period of time: the electric trees are micro voids that are the final stage of water trees. They are the consequence of surges, electrical impulses or partial discharge that increase pressure on permeated water trees and alter permanently the insulation. Routine procedures (such as snapping a capacitive charge, bad switching procedures or inappropriate cable testing) if not performed properly may also produce electric trees. These micro-faults cannot be rejuvenated.

Pre-1980 vintage cables suffer a rapid degradation in AC breakdown performance during the first decade after the cable is installed. The cable then continues to degrade in performance, but at a much slower rate.

This data would indicate that today's power system reliability is of great concern to all electrical utility managers with old underground power cables. The "Post-treat" line in Figure 1 demonstrates how reliability can be rapidly increased using the silicone treatment technology. ACBD performance is improved by .5 % per day reaching an increase of 350% over a two-year period. Over the next 20 or 30 years the treated cable's ACBD maintains high levels that out-perform untreated cable.

Canadian Cable Injection Services (CCIS) is the Canadian leader in applying life-extension technologies to water-damaged power cables, using the patented CableCURE silicone-based injection fluids. CableCURE has restored over 70 million feet of cable world wide.

EXAMINING ADVANCED TRANSMISSION TECHNOLOGIES - PART II

By Jeff Dagle, Steve Widergren, John Hauer, Pacific Northwest National Laboratory
Tom Overbye, University of Illinois at Urbana-Champaign

NEW DEMANDS ON THE TRANSMISSION GRID

The core objective underlying electricity industry restructuring is to provide consumers with a richer menu of potential energy providers while maintaining reliable delivery. Restructuring envisions the transmission grid as flexible, reliable, and open to all exchanges no matter where the suppliers and consumers of energy are located.

However, neither the existing transmission grid nor its current management infrastructure can fully support such diverse and open exchange. Transactions that are highly desirable from a market standpoint may be quite different from the transactions for which the transmission grid was designed and may stress the limits of safe operation. The risks they pose may not be recognized in time to avert major system emergencies, and, when emergencies occur, they may be of unexpected types that are difficult to manage without loss of customer load.

The transmission system was originally constructed to meet the needs of vertically integrated utilities, moving power from a local utility's generation to its customers. Interconnections between utilities were primarily to reduce operating costs and enhance reliability. That is, if a utility unexpectedly lost a generator, it could temporarily rely on its neighboring utilities, reducing the costs associated with having sufficient reserve generation readily available. The grid was not designed to accommodate large, long-distance transfers of electric power.

One of the key problems in managing long-distance power transfers is an effect known as "loop flow". Loop flow arises because of the transmission system's uncontrollable nature. As power moves from seller to buyer, it does not follow any prearranged "contract path". Rather, power spreads (or loops) throughout the network.

As an example, Figure 3 shows how a transmission of power from a utility in Wisconsin to the Tennessee Valley

Authority (TVA) would affect lines through a large portion of the Eastern Interconnection.

A color contour shows the percentage of the transfer that would flow on each line; lines carrying at least two percent of the transfer are contoured. As this figure makes clear, a single transaction can significantly impact the flows on hundreds of different lines.

The problem with loop flow is that, as hundreds or thousands of simultaneous transactions are imposed upon the transmission system, mutual interference develops, producing congestion. Mitigating congestion is technically difficult, and very complex problems emerge when paths are long enough to span several regions that have not had to coordinate such operations in the past. These problems include (but are not limited to) the lack of: effective procedures, operating experience, computer models, and integrated data resources. The sheer volume of data and information concerning system conditions, transactions, and events is overwhelming the existing grid management's technology infrastructure.

Figure 3: Loop Flow of Power Transfer from Wisconsin to TVA

Increasing the transfer capacity of the NTG will require combined application of hardware and information technologies. On the hardware side, many technologies can be developed, refined, or simply installed to directly reinforce current transmission capabilities. These technologies range from passive reinforcements (such as new AC lines built on new rights of way or better use of existing AC rights of way by means of innovative device configurations and materials) to super-conducting equipment to large-scale devices for routing grid power flow. High-voltage direct current (HVDC) and FACTS technologies appear especially attractive for flow control. Effectively deployed and operated, such technologies can be of great value in extending grid capabilities and minimizing the need for construction of new transmission.

The strategic imperative, however, is to develop better information resources for all aspects of grid management — planning, development, and operation. Technologies such as large-scale FACTS generally require the support of a wide-area measurement system (WAMS), which currently exists only as a prototype. Without a WAMS, a FACTS or any major control system technology cannot be adjusted to deliver its full value and, in extreme cases, may interact adversely with other equipment. FACTS technology can provide transmission "muscle" but not necessarily the "intelligence" for applying it.

An example of the information that a WAMS can provide is shown in Figure 4. Review of data collected on the Bonneville Power Administration (BPA) WAMS system following a grid disturbance in 1996, suggests that the information that system behavior was abnormal and that the power system was unusually vulnerable was buried within the measurements streaming into and stored at the control center.

Had better tools been available at the time, this information might have given system operators approximately six minutes' warning of the event that triggered the system breakup.

Better information is key to better grid management decisions.

INFORMATION GAPS IN GRID MANAGEMENT

As the grid is operated closer to safe limits, knowing exactly where those limits are and how much operating margin remains becomes increasingly important. Both limits and margins must be estimated through computer modeling and combined with operating experience that the models might not and often cannot reflect.

The "edge" of safe operation is defined by numerous aspects of system behavior and is strongly dependent on system operating conditions. Some of these conditions are not well known to system operators, and even those that are known may change abruptly. Important conditions include network loading, operating status and behavior of critical transmission elements, behavior of electrical loads, operating status and behavior of major control systems, and interactions between the grid and the generators connected to it. Full performance of the transmission grid requires that generators provide adequate voltage support plus a variety of dynamic support functions that maintain power quality during normal conditions and assist the system during disturbances.

All of these conditions have become more difficult to anticipate, model, and measure directly. Industry restructuring has exacerbated these difficulties by requiring that transmission facilities be managed with a minimum of information concerning generation assets. To borrow a phrase from EPRI, this is one of many areas where there is a "critical interactive role" between "technology and policy."

Many cases in recent years have revealed that the "edge" of safe grid operation is much closer than planning models had suggested. The Western System breakups of 1996 are especially notable in this respect (see Figure 5), but there have been less conspicuous warnings before and since. Uncertainties regarding actual system capability is a long-standing problem, and it has counterparts throughout the NTG.

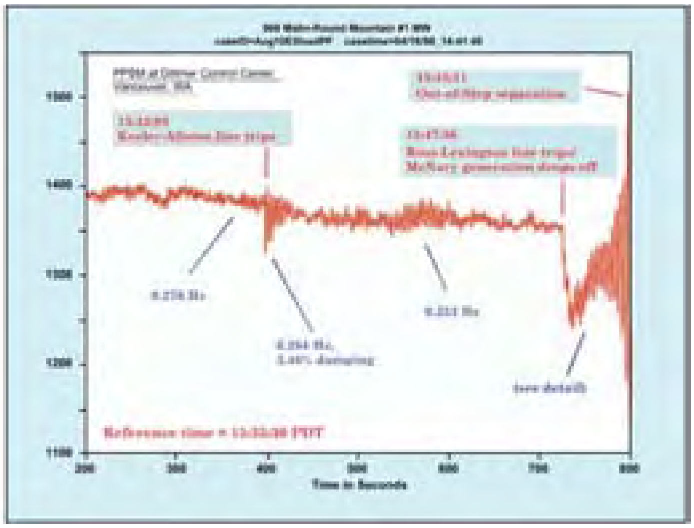


Figure 4. Possible warning signs of the Western Systems breakup of August 10, 1996 – an example of information available from WAMS

Developing and maintaining realistic models for power system behavior is technically and institutionally difficult, and it requires higher-level planning technology than has previously been available. An infusion of enhanced planning technology — plus knowledgeable staff to mentor its development and use — is necessary to support timely, appropriate, and cost effective responses to system needs. Better planning resources are the key to better operation of existing facilities, to timely anticipation of system problems, and to full realization of the value offered by technology enhancements at all levels of the power system.

CHALLENGES AND OPPORTUNITIES IN NETWORK CONTROL

As noted earlier, the existing AC transmission system cannot be directly controlled; electric flow spreads through the network as dictated by the impedance of the system components. For a given set of generator voltages and system loads, the power-flow pattern in an electrical network is determined by network parameters.

Control of network parameters in an AC system is usually quite limited, so scheduling of generators is the primary means for adjusting power flow for best use of network capacity. When generator scheduling fails, the only alternative is load control, either through voltage reductions or suspension of service. Load control can be necessary even when some lines are not loaded to full capacity.

A preferred solution would be a higher degree of control over power flow than is currently possible, which would permit more effective use of transmission resources. Conventional devices for power-flow control include series capacitors to reduce line impedance, phase shifters, and fixed shunt devices that are attached to the ends of a line to adjust voltages.

All of these devices employ mechanical switches which are relatively inexpensive and proven but also slow to operate and vulnerable to wear, which means that it is not desirable to operate them frequently and/or use a wide range of settings; in short, mechanically switched devices are not very flexible controllers. Nonetheless, they are still the primary means used for stepped control of high power flows.

HVDC transmission equipment offers a much greater degree of control. If the support of the surrounding AC system is sufficient, the power flowing on an HVDC line can be controlled accurately and rapidly by means of signals applied to the converter equipment that changes AC power to DC and then back to AC. In special conditions, HVDC control may also be used to modify AC voltages at one or more converters. This flexibility derives from the use of solid-state electronic switches, which are usually thyristors or gate turn-off (GTO) devices.

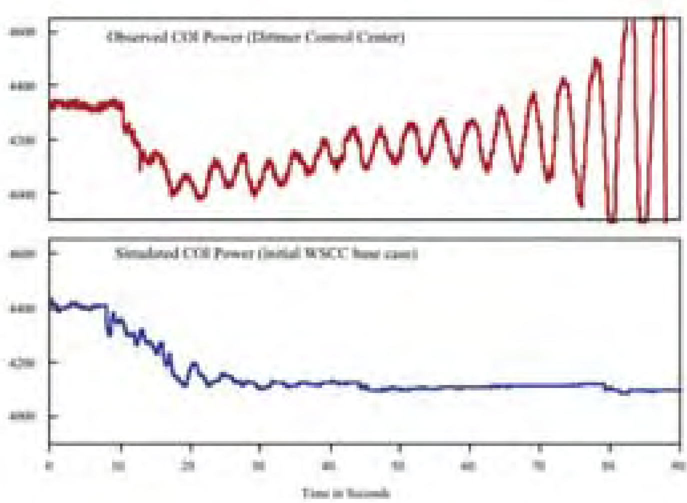


Figure 5. Modeling failure for Western System breakup of August 10, 1996. (MW on California-Oregon Interconnection)

Although HVDC control can influence overall power flow, it can rarely provide full control of the power flowing on particular AC transmission lines. However, conventional power-flow controllers that are upgraded to use electronic rather than mechanical switches can achieve this control. This upgrade opens the way to a broad and growing class of new controller technology known as FACTS. Very few utilities are in a position to break this impasse as the management functions for which high-level technologies like FACTS are of primary relevance are passing from the utilities to a newly evolving infrastructure based upon Regional Transmission Organizations (RTOs), Independent System Operators (ISOs), and other entities.

This transition is far from complete in most areas of the U.S., and as yet there is no “design template” for the nature and the technology needs of this new infrastructure.

THE STATE OF ONTARIO'S SMART METERING INITIATIVE

By Bruce B. Campbell, Vice President, Corporate Relations & Market Development, Independent Electricity System Operator

In less than two years since the Ontario government announced an ambitious plan to install smart electricity meters in all homes and small businesses by the end of 2010, the province has come a long way.

In this short time, the project to build the backbone of the provincial smart metering system is well advanced, over 680,000 smart meters have been installed and several leading local distribution companies (LDC) are gearing up for the changes that smart meters will bring to their businesses.

ONTARIO'S SMART METERING SYSTEM

Ontario's smart metering system has two key components – the smart meters themselves, with their local supporting infrastructure, and the central infrastructure that will house province-wide data. While LDCs have been purchasing and installing customers' smart meters, the Independent Electricity System Operator (IESO) has been developing the Meter Data Management Repository (MDM/R), the data infrastructure that will be at the core of the system. The MDM/R is essentially a large database that will receive, verify, store and manage electricity consumption data from customers' smart meters, and provide that data to LDCs, appropriately processed, for customer billing.

Installing a centralized system like the MDM/R helps to create a number of efficiencies. First, it eliminates the burden on each of the province's 90 plus LDCs to build and manage their own data storage and management systems. A common system also ensures that uniform data collection and delivery processes and standards are in place across the province – for the first time will provide easily accessible, consistent province-wide information on electricity consumption.

The project has come a long way since the MDM/R specifications were developed last year. With the support of LDCs and IBM, the IESO's contracted supplier, the MDM/R has been designed and developed and this Fall the first group of LDCs will be integrating their own smart meter systems into the provincial MDM/R.

THE BENEFITS OF SMART METERS ARE FAR REACHING

As Ontario moves toward a "conservation culture", smart meters will be key to informing and empowering consumers. In Ontario today, four and a half million electricity consumers pay a fixed price for electricity, regardless of their time of use. These consumers have little incentive to shift their usage away from periods when demand for electricity is high and the system is strained. Smart meters have the potential to change this.

Measuring electricity use on an hourly basis, smart meters provide consumers with the knowledge they need to manage their personal electricity use. This knowledge, coupled with time-of-use (TOU) electricity rates, provides consumers with the financial incentive to shift or reduce their consumption. Consumers who modify their electricity usage patterns will save money, contribute to maintaining the reliability of the electricity system and help lessen the impact on the environment.

As the system operator, the IESO is also anticipating the system reliability benefits smart meters can offer. The TOU rates established by the Ontario Energy Board (OEB) have been set to reflect the cost to supply electricity at different times during the day, and accordingly are significantly higher when demand for electricity is usually at its highest. If consumers respond by shifting their electricity use away from the higher priced periods, they will help reduce the strain on the electricity grid during those peak times.

And with enough additional consumer demand response through smart meters, there could be significant cost savings across the system. For instance, if Ontario consumers can help to reduce or eliminate the peak demands that occur in so few hours, the need to build expensive peaking generators could be deferred. For instance, despite the fact that peak demand reached 27,005 megawatts (MW) last summer, it exceeded 25,000 MW in only 32 hours for the entire year. Reducing demand in these hours could lead to millions of dollars in savings for Ontario consumers.

CONSUMER INFORMATION WILL BE CRITICAL

The roll-out of smart meters across the province will change the way consumers view electricity use and cost, but these changes do not come without some challenges.

One of these is to ensure that electricity consumers are adequately informed about smart meters and how best to take advantage of the opportunities they offer. Unlike the May 1 opening of Ontario's electricity market in 2002, the switch to smart meters will roll out over several years. This should facilitate ongoing consumer education and feedback on how best to enhance the value provided by smart meters. And the various pilots being conducted with LDCs provide a good opportunity for LDCs to become familiar with new technology and consumers familiar with TOU rates. As always, delivering benefits for customers will be the true measure of success.

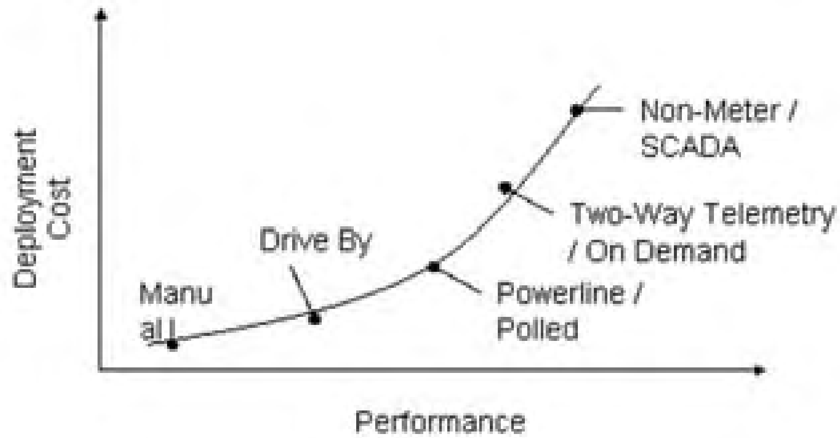
EVOLVING TECHNOLOGIES IN AMR

The first significant injection of technology to the AMR industry was a drive-by system. Transmitters, mounted onto the meters themselves, send a signal to a meter-reading device located in the back of a utility van. As the van drives through a neighborhood, the meter reads would be downloaded. This technology requires the orchestration of RF signal processors to transmit the data, database software to collect the meter reads, and interface software to validate data and hold it for billing purposes. Itron has become the clear champion for this technology pathway.

The state-of-the-art rarely stands still and AMR technology is no different. CellNet, now a division of Schlumberger, replaced the need for drivers to collect meter reads with wireless networks that span entire utility service areas. Through the CellNet system, meter reads are transmitted over a cellular network, validated by CellNet software, and made available to utility offices over a secure internet connection. This type of system provides further cost savings but requires a larger up-front investment and commitment.

Since then, two other technologies have demonstrated significant value. First, powerline technologies championed by Hunt and TWACS enable electricity utilities to collect meter reads over their existing powerline transmission networks. These systems transmit data signals through electrical powerlines themselves and have the advantage of being deployable to every location that an electric utility serves. One cannot assume the same reach of powerline technology for gas and water utilities. Second, advances in two-way telemetry over public or private networks by firms such as SmartSynch and Tantalus have enabled utilities to deploy a meter reading system that gathers meter data in real time.

Given the variety of the technologies, each with its own cost structure and value points, how should a utility select a standard to deploy throughout their service area? An installation cost to performance roadmap for AMR is provided here (above).



However, conversations with others quickly highlighted the shifts within this paradigm. For instance, the Tantalus wireless system, which uses public spectrum over a private network for transmission of meter data, provides the performance of two-way telemetry but with a significantly lower cost structure. Elsewhere, MeterSmart has developed a means to provide some of the functionality of two-way telemetry while using the powerline communication system for transporting signals. To further complicate the temporary clarity, the company should expect further industry evolution. With 86% of the market up for grabs, each technology provider has significant incentive to innovate and capture the future market.

TOUCH TECHNOLOGY AMR

With touch-based AMR, a meter reader carries a handheld computer or data collection device with a wand or probe. The device automatically collects the readings from a meter by touching or placing the read probe in close proximity to a reading coil enclosed in the touchpad. When a button is pressed, the probe sends an interrogate signal to the touch module to collect the meter reading. The software in the device matches the serial number to one in the route database, and saves the meter reading for later download to a billing or data collection computer. Since the meter reader still has to go to the site of the meter, this is sometimes referred to as "on-site" AMR.

RADIO FREQUENCY AMR

Radio frequency-based AMR can take many forms. The more common ones are Handheld, Mobile, and Fixed network. There are both two-way RF systems and one-way RF systems in use that use both licensed and unlicensed RF bands.

In a two-way system, a radio transceiver normally sends a signal to a particular transmitter serial number, telling it to wake up from a resting state and transmit its data. The Meter attached transceiver and the reading transceiver both send and receive radio signals and data. In a one-way "bubble-up" type system, the transmitter broadcasts readings continuously every few seconds. This means the reading device can be a receiver only, and the meter AMR device a transmitter only. Data goes one way, from the meter AMR transmitter to the

Continued on Page 26

PQ Analyzers

Power Loggers

PQ Recorders

PQ Loggers

Continued from Page 24

meter-reading receiver. There are also hybrid systems that combine one-way and two-way technologies, using one-way communication for reading and two-way communication for programming functions.

RF-based meter reading usually eliminates the need for the meter reader to enter the property or home, or to locate and open an underground meter pit. The utility saves money by increased speed of reading, has lower liability from entering private property, and has less chance of missing reads because of being locked out from meter access.

HANDHELD AMR

Handheld AMR is where a meter reader carries a handheld computer with a built-in or attached receiver/transceiver (radio frequency or touch) to collect meter readings from an AMR capable meter. This is sometimes referred to as "walk-by" meter reading since the meter reader walks by the locations where meters are installed as they go through their meter-reading route. Handheld computers may also be used to manually enter readings without the use of AMR technology.

Handheld AMR systems can be touch based. In this system, a meter reader physically touches the MIU with a probe making contact with the device and automatically collecting its data. The probe sends out an interrogator signal and in return receives an answer from the MIU, matching the data to a prerecorded serial number for the meter being read. This system has aspects of both old and new, with automatic readings but still dependent on human meter readers.

MOBILE AMR

Mobile or "Drive-by" meter reading is where a reading device is installed in a vehicle. The meter reader drives the vehicle while the reading device automatically collects the meter readings. Often for mobile meter reading, the reading equipment includes navigational and mapping features provided by GPS and mapping software. With mobile meter reading, the reader does not normally have to read the meters in any particular route order, but just drives the service area until all meters are read. Components often consist of a laptop or proprietary computer, software, RF receiver/transceiver, and external vehicle antennas. Mobile units are mounted on vehicles or backpacks and rely entirely on wireless radio frequency communication. These drive-by readings are conducted on a monthly basis with both the mobile units and the MIUs sending and receiving information.

FIXED NETWORK AMR

Fixed Network AMR is a method where a network is permanently installed to capture meter readings. This method can consist of a series of antennas, towers, collectors, repeaters, or other permanently installed infrastructure to collect transmissions of meter readings from AMR capable meters and get the data to a central computer without a person in the field to collect it. There are several types of network topologies in use to get the meter data back to a central computer.

Fixed relay systems can be either wireless or via cable, with the signal sometimes sent along the power lines themselves. These can be interrogative, or "bubble up", systems, where unprompted MIUs transmit continuous readings every few minutes. In mobile systems, the human operator is nearly eliminated, except for the driver of the vehicle whose interrogator unit is accessing multiple MIUs simultaneously. In fixed relay systems, the human operator is completely replaced.

RF technologies commonly used for AMR include:

- Narrow Band (single fixed radio frequency);
- Spread Spectrum;
- Direct Sequence Spread Spectrum (DSSS);
- Frequency Hopping Spread Spectrum (FHSS).

POWER LINE CARRIER AMR

Power Line Carrier (PLC) AMR is a method where electronic data is transmitted over power lines back to the central computer. This would be considered a fixed network type system, and is primarily used for electric meter reading. Some providers have interfaced gas and water meters to feed into a PLC type system.

ADVANCED AMR

Originally AMR devices just collected meter readings electronically and matched them with accounts. As technology has advanced, additional data can now be captured, stored, and transmitted to the main computer. This can include events alarms such as tamper, leak detection, low battery, or reverse flow. Many AMR devices can also do data logging. The logged data can be used to collect time of use data that can be used for water or energy use profiling, time of use billing, demand forecasting, rate of flow recording, leak detection, flow monitoring, etc.

COLORADO SPRINGS UTILITIES CASE STUDY

Colorado Springs Utilities is deploying an automated meter reading (AMR) program, with full deployment taking place from late 2006 through 2010.

Using wireless radio transmitters, AMR remotely reads customer meters and then transfers the data into the billing system. AMR will reduce the need for meter readers to manually gather utility meter readings each month. Many utilities are using AMR as a way to improve customer service and control their meter reading costs, especially in areas with fenced yards, dogs, landscaping and other issues that make accessing meters difficult or unsafe. Benefits include improved customer service, which includes:

- Minimizing the need to access customer property to read meters;
- Reducing customer complaints and damage claims resulting from monthly visits to customer site;
- Call resolution improvement – billing complaint calls will be handled more quickly due to availability of more frequent meter readings;
- No need for customer to read their own meters due to meter access issues;
- Controlled meter reading costs;
- Enhanced customer convenience;
- Fewer employee injuries, especially in areas with fenced yards, dogs and landscaping;
- Improved billing accuracy;
- A reduction in operational costs.

The AMR Technologies Report can be found at EnergyBusinessReports.com, an industry think tank and research report publisher.

A SIMPLE ANSWER TO ANIMAL INTRUSION ON POWER SITES

By Margaret Bennett, Kinectrics Inc.

Raccoons, squirrels and the like may be seen as cute by some, but quickly become less lovable when they get into power stations, interfere with equipment and cause disruptive, sometimes costly outages, not to mention their own unpleasant demise.

One back-to-basics solution to the serious problem of animal intrusion currently making a name on the market is Kinectrics' PowerKage non-electric fence, a passive defense system for transformers and other electrical systems that works 24/7 to protect clients' equipment. The PowerKage non-electric fence has quickly become established among animal barrier products available to the industry, following the system's successful installation at a number of North American transmission stations. Kinectrics has just recently been awarded another contract to install the PowerKage at 3 large utility substations in Southern Ontario.

NON-ELECTRIC TECHNOLOGY

A key feature of PowerKage is its simplified design, which does not rely on electric power to operate. This offers numerous safety benefits for station personnel, the public, and even any potential 4-footed intruders that are effectively prevented from connecting with power equipment.

"Kinectrics developed PowerKage as a non-electric technology because, during an experimental program to test barriers conducted over several years, it proved to be the most effective option in preventing the ground passage of small animals — even when tested under worst case conditions," says Paul Patrick, Ph. D., of the PowerKage system design team.

DESIGN SIMPLICITY

Kinectrics' PowerKage non-electric fence is modular in design and easy to install, disassemble or reconfigure. The modular design of the fence system allows authorized personnel to easily remove or take down sections where required to allow access to work locations if needed. The basic fence components consist of 6-foot units, 26" units, inside corner units and outside corner units. Gates, for both vehicle and personnel access, are easily accessed by one person in less than a minute, and are identified by signage to distinguish their location on the fence line.

Personnel gates are constructed in six-foot panel sections mounted with robust heavy-duty double hinges that provide a four-foot opening (180-degree swing) for entry with both left and right hinge options. Personnel gates are also supplied with a hinged, fold-down panel at the bottom of the gate to allow the upper gate portion to swing freely above accumulated snow drifts.

The vehicle gate is designed to provide an access opening of 12 feet within an 18-foot unit. Vehicle gates are built with robust heavy duty double hinges that allow operators to fold both gates up to180 degrees. Gates come with bolt-action locks that can be padlocked if necessary.

The PowerKage non-electric fence (and associated deterrent technologies) does not require special technical work instructions, work protection practices, monitoring, or indicators for maintenance and general operation. The PowerKage non-electric fence is grounded to the transformer station grounding grid to provide continuous ground fault protection when gates are opened, or when panels and sections of the fence have been removed. PowerKage poses no hazard to grounds maintenance crews or inadvertent intruders. Components are engineered for durability and minimal maintenance.

The PowerKage system offers unique flexibility — fence layouts can be focused to contain specific problem areas (i.e. using one or more, smaller fence enclosures within a utility's premises). If required, PowerKage can also be combined with security fencing, an option not typically available with electric fencing.

Specific PowerKage system details are designed to meet to the requirements of individual station sites. For example, the PowerKage system has additional features that are designed to prevent animals from gaining access by digging, or using branches, lines and other objects to gain entry to power sites.

OPERABILITY

The PowerKage system layout is designed to minimize interference with the operation of substation equipment. The fence is either kept very close to fuses and switches that need to be operated such that they can be accessed from outside the fence, or far enough away that they will not interfere with operator's switch pole. One person can remove the necessary bolts or pins to remove any fence panel as necessary. Any grounding wires installed are connected to the structure's feet and not the panels.

MINIMAL MAINTENANCE

Kinectrics PowerKage non-electric animal control fence is designed to be maintenance free. Barring exceptional circumstances, no spare parts should be required for the system's 25-year life cycle. There are no controllers to be damaged by lightning or weather. The only tools required for a PowerKage installation are a level, rake, shovel, and wrench set.

Preventing animal intrusion is important for utilities. As Christine McLeod, an Edison regional manager in the U.S. has observed, "Outages caused by animals may not always be major, but when they happen at regular intervals they drive people crazy."

INTERSTATE TRANSMISSION VISION FOR WIND INTEGRATION

American Electric Power, working at the request of, and in partnership with, the American Wind Energy Association (AWEA), presents a high-level, conceptual interstate transmission plan that could provide a basis for discussion to expand industry infrastructure needs in the future. AEP believes that expansion of Extra High Voltage (EHV) interstate transmission systems provides increased reliability, market efficiency, environmental optimization and national security for the benefit of electric customers across the United States.

AEP currently owns two wind farms in Texas with a total capacity of 310 MW and has long-term agreements to purchase 467 MW of output from wind farms in Oklahoma and Texas. We support federal and state policies that reduce electricity production costs by facilitating deployment of these technologies, such as production tax credits and assurances from state regulators for recovery of investments. However, AEP does not support a national mandate that stipulates a Renewable Portfolio Standard (RPS) in the overall electric generation resource mix.

The nation's transmission system is at a critical crossroads. The United States continues to experience transmission bottlenecks that compel the excessive use of older, less efficient power plants. Transmission grid capacity constraints must be eliminated to ensure a fair, vibrant and open market that gives us the flexibility to deliver economic and environmentally friendly energy to consumers.

AEP believes the nation's transmission system must be developed as a robust interstate system, much like the nation's highways, to connect regions, states and communities. Our highly efficient and reliable 765 kilovolt (kV) network provides a strong foundation for this system because it is the most efficient, proven transmission technology available in United States.

The hope is that this article will promote discussion and set the stage for action.

Some experts believe the U.S. offers quantities of wind energy resources well in excess of future projected electricity needs. One of the biggest long-term barriers in the adoption of wind energy to meet this growing demand is the physical limitations on the nation's current electric transmission system.

EXECUTIVE SUMMARY

Some experts believe the U.S. offers quantities of wind energy resources well in excess of future projected electricity needs. One of the biggest long-term barriers in the adoption of wind energy to meet this growing demand is the physical limitations on the nation's current electric transmission system. The nation's bulk transmission system is currently inadequate to deliver energy from remote wind resource areas to electrical load centers; located mainly on the East and West coasts. AEP believes that this barrier can be overcome by building transmission infrastructure that will enable wind power to become a larger part of the nation's power generation resource mix. This transmission system expansion will bring many additional societal benefits, including increased reliability and greater access to lower cost and environmentally friendly resources.

This conceptual transmission plan is illustrative and should be treated as such. AEP and other power industry leaders believe 765 kV in particular has many benefits over other options. There are, however, many possible configurations that could be leveraged to integrate wind and other resources. The goal is merely to present this proposal as one possible scenario to illustrate the potential that exists. Additionally, the intent of this visionary plan is to provide an example that encourages the type of thinking and, most importantly, consensus and action necessary to bring transmission and wind generation together on a national scale.

The result of this effort, shown in Exhibit 1, is a theoretical interstate 765 kV electricity transportation system that encompasses major portions of the United States connecting areas of high wind resource potential with major load centers. It is projected that an interstate EHV transmission system could enable significantly greater wind energy penetration levels by providing an additional 200-400 GW of bulk transmission capacity. The total capital investment is estimated at approximately $60 billion (2007 dollars). While it is by no means the total solution, this initiative illustrates the opportunities that exist, and what might be possible with adequate cooperation, collaboration, and coordination – "3Cs".

This article describes the data and methodology used in developing this plan, costs, benefits and wind deploy-

Continued on Page 32

Continued from page 30

ment potential from the plan, and the efforts that will need to be undertaken to make the visionary concept a reality.

BACKGROUND

This endeavor is a derivative effort associated with a joint study involving AWEA, U.S. Department of Energy (DOE), and National Renewable Energy Laboratory (NREL). This study is committed to developing an implementation plan that would enable AWEA's proposal to provide up to 20% (approximately 350 GW) of the nation's electricity from wind energy.

AEP, along with members of several other wind, electric utility, RTO, and governmental organizations, was invited as a consultant to provide guidance and insight in regard to transmission. Though AEP does not support RPS mandates or penalties for not achieving mandates, AEP does support enabling renewable generation through transmission development and goals toward that end. Transmission infrastructure is a critical component in the development of wind generation, in particular on a national scale with such aggressive goals. It is this relationship that compelled these organizations to collectively develop an illustrative vision for the bulk transmission system to satisfy this target.

EXPANDING 765 KV TECHNOLOGY

The power grid in much of the U.S. today is characterized by mature, heavily-loaded transmission systems. Both thermal and voltage-related constraints affecting regional power deliveries have been well documented on systems operating at voltages up to, and including, 500 kV. While various mitigating measures are being proposed and/or implemented, they are largely incremental in scope and aimed at addressing specific, localized network constraints. Incremental measures are a deliberate means of shoring up an existing system in the near-term, but certainly do not facilitate the incorporation of renewable energy and other generation resources on the scale required to meet the proposed goal. In the longer term, a mature system facing growing demands is most effectively strengthened by introducing a new, higher voltage class that can provide the transmission capacity and operating flexibility necessary to achieve the goal of a competitive electricity marketplace with wind power as a major contributor. In addition, a new

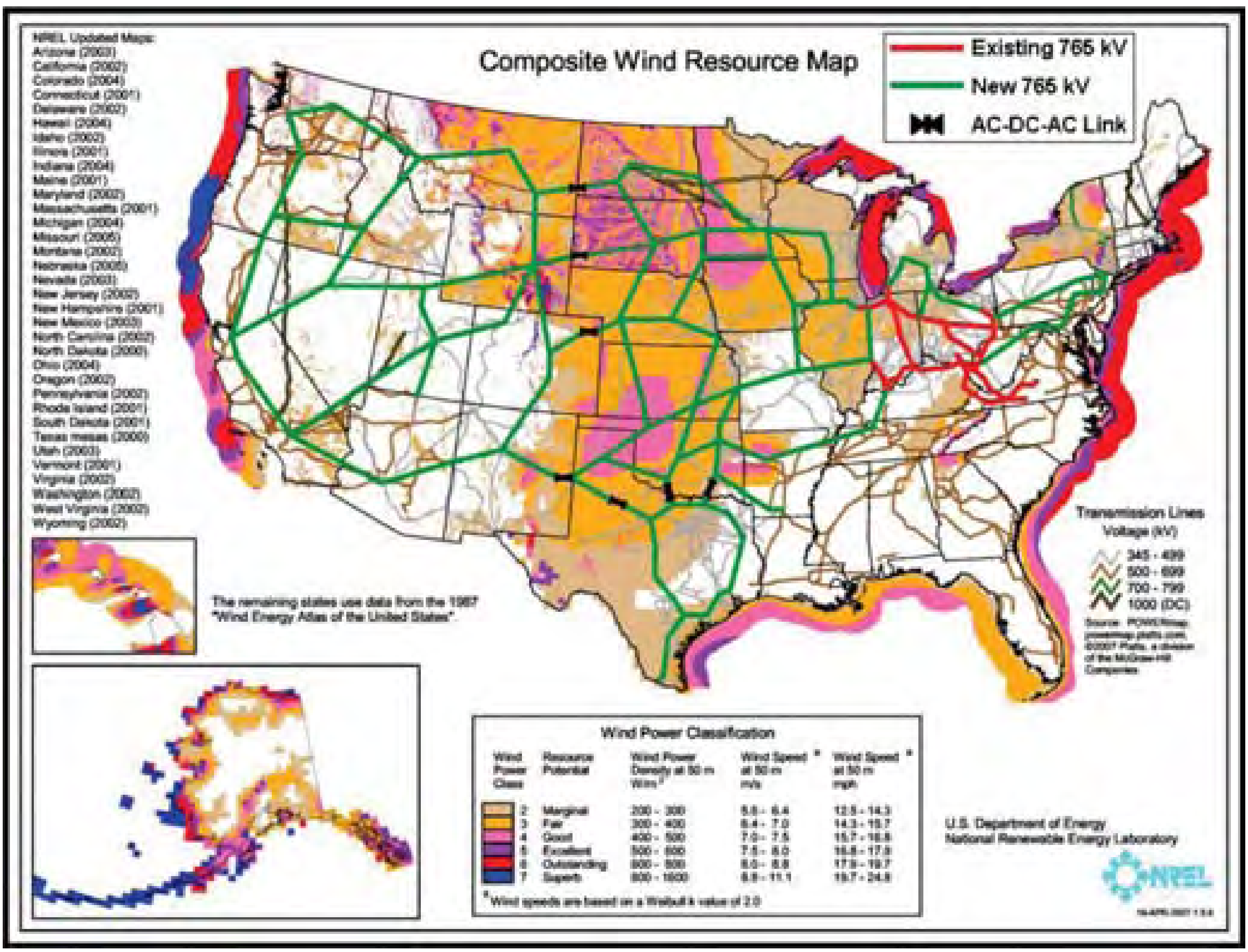


Exhibit 1: Conceptual 765 kV backbone system for wind resource integration (edited by AEP).

high-voltage infrastructure would facilitate the use of the latest transmission technologies - maximizing the performance, reliability, and efficiency of the system.

The existing AEP 765 kV system provides an excellent platform for a national robust transmission infrastructure. The use of 765 kV AC technology would enable an expansion into a new high-capacity bulk transmission grid overlaying the existing lower voltage system, with both systems easily integrated where so required. By contrast, traditional DC technology is generally limited in its application to point-to-point transmission. Wind generation resources often cover a wide geographic area, and the cost to create multiple connections to a DC line could be substantially higher. A 765 kV AC network would allow for less complicated future connections of resources and integration into the underlying system. This type of integrated AC grid with ample capacity for future growth provides a solid foundation for reliable service and ease of access to all users. Furthermore, this network frees up capacity on lower voltage systems such as 500kV, 345 kV, and 230 kV. This is particularly important as this additional capacity allows operational and maintenance flexibility, as well as the ability to connect new generation resources onto the underlying system.

To assess the load carrying ability, or loadability of a high-voltage transmission line, the concept of Surge Impedance Loading (SIL) is commonly used. SIL is a convenient yardstick for measuring relative loadabilities of transmission lines operating at different voltages, and is that loading level at which the line attains reactive power self-sufficiency. For example, an uncompensated 765 kV line has a SIL of approximately 2,400 MW. By contrast, a typical 500 kV line of the same length has a SIL of approximately 910 MW and a 345 kV line approximately 390 MW. The relative loadabilities of 765 kV, 500 kV, and 345 kV considering 150 miles line length (from the St. Clair Curve), are 3,840 MW, 1,460 MW, and 620 MW, respectively. It is apparent that a 765 kV line, 150 miles in length, can carry substantially more power than a similarly situated 500 kV or 345 kV line. Generally, about six single-circuit (or three double-circuit) 345 kV lines would be required to achieve the load carrying ability of a single 765 kV line. Relative loadabilities of the transmission lines also can be viewed in terms of transmission distances over which a certain amount of power, say 1,500 MW can be delivered. For a 765 kV line, this loading represents approximately 0.62 SIL (1,500/2,400 = 0.625) which, according to the St. Clair Curve, can be transported reliably over a distance of up to 550 miles. By contrast, a 345 kV line carrying the same amount of power can transport reliably only up to 50 miles; this distance would increase to about 110 miles for a double-circuit 345 kV line.

Additionally, a line's capability can be increased further with adequate voltage compensation through the use of devices such as Static Var Compensators (SVC). High Surge Impedance Loading (HSIL) technology at 765 kV could also be considered. While HSIL lines have not been employed in the United States, studies indicate these lines could provide additional capacity with a relatively modest increase in cost. Further research and development into these and other promising technologies is particularly important in order to create the most advanced and reliable future transmission system.

A further benefit of the use of 765 kV lines is the reduced impact on the environment. As stated above, one 765 kV line can carry a substantially higher amount of power than transmission lines operating at lower voltages. For instance, a single 765 kV line can carry as much power as three 500 kV lines or six 345 kV lines. The result is that fewer lines need to be constructed and less right-of-way clearing necessary compared to lower voltages for the same power delivery capability. Use of higher voltages also results in a more efficient system. By moving power off the lower voltage systems having higher resistance and onto the 765 kV, real and reactive power losses are reduced. It can also be demonstrated that a 765 kV line incurs only about one-half of the power losses of a six-circuit 345 kV alternative, both carrying the same amount of power. This reduction in transmission losses will not only reduce overall energy consumption across the system, but also the need for generating capacity additions, resulting in a significant reduction in capital requirements, fuel consumption, and emissions.

> By moving power off the lower voltage systems having higher resistance and onto the 765 kV, real and reactive power losses are reduced.

METHODOLOGY

In developing this conceptual 765 kV overlay, it is necessary to make a number of significant assumptions. While the routes and connections are derived based upon engineering judgment, the impact of the proposed overlay would require significant additional study by a number of different stakeholders. In addition, the transmission corridors shown on this diagram are not meant to preclude or replace any proposed projects. Rather, it is meant to suggest one possibility that is believed to satisfy the goal of connecting areas of high wind potential with load centers across the country.

Our analysis relied on input from the on-going study, wind resource maps developed by the NREL, and individual contributions from other participants. From this information, areas of high wind potential as well as cost-effective transmission corridors to major load centers were identified.

Other existing transmission studies were also relied upon as pertinent sources. In many cases, these existing proposals include more detailed analyses and provided sound technical supporting information. For example, in the case of Midwest ISO's MTEP06 report and the proposal for the Texas Competitive Renewable Energy Zone (CREZ) initiative produced by Electric Transmission Texas (ETT-AEP joint venture with MidAmerican Energy Holdings Company), actual study of wind integration using 765 kV was performed. These reports offered qualified information to help formulate the overall plan. Furthermore, a number of other projects have been proposed in other areas of the country, including several west of the Rocky Mountains. While these projects do not necessarily consider use of 765 kV, they do identify corridors where additional transmission is needed.

The vision map was created using the following process:

1. Identify and plot the existing 765 kV system and other 765 kV proposals to use as a foundation for expansion.

2. Using other proposals, determine corridors that have been identified as lacking transmission capacity but may not have been considered for 765 kV.

3. Identify major load centers and areas of high wind potential. Create links between areas without proposed transmission development that are determined to be cost-effective.

4. Connect the proposed 765 kV segments at strategic locations to form an integrated 765 kV network overlay that makes sense from a high level transmission planning and operations perspective. These locations would be substations, existing or new, that best allow dispersion of power into localized areas.

It is expected that this 765 kV overlay could provide enough capacity to connect up to 400 GW of generation. This was calculated by dividing the 765 kV network into loops and nodes where potential wind generation connections are expected. Each of these connections would be required to have two or more outlets on the 765 kV, and therefore would permit a level of generation equal to the capability of a single 765 kV line (allows outage of the other outlet). For the proposed system as shown in Exhibit 1, there are approximately 55 such potential connections (of course, in reality there would likely be many more connections in smaller incremental sizes). Since the length of these lines varies, assigning a specific SIL value to the overall system can be complicated.

However, a typical 765 kV line has physical equipment limitations upwards of 4,000 MVA and conductor limitations upwards of 10,000 MVA. A loadability range of 3,600-7,200 MW (1.5-3 times base SIL) can be credibly assumed for a given line. This equates to a total generation connection potential of approximately 200-400 GW, with even higher levels achievable by utilizing proper technologies. This also does not account for displaced generation and additional capaci-

It is expected that this 765 kV overlay could provide enough capacity to connect up to 400 GW of generation.

ty available on the lower voltage systems, which may augment this potential.

THE CONCEPTUAL PLAN

The result of this process is a 765 kV backbone system that provides cost-effective connections from areas of high wind potential to major load centers. Furthermore, the overlay would provide significant reliability benefits to the overall transmission system in these areas. Exhibit 1 shows the theoretical 765 kV backbone transmission system as developed in this effort. The base graphic on the map is the Composite Wind Resource Map developed by the NREL. The color contours on the map show the wind power density and subsequent resource potential across the country. Transmission lines 345 kV and above are shown with the existing 765 kV system highlighted in red. The conceptual 765 kV overlay expansion is shown in green. DC connections between the regional interconnections are maintained, though optimal integration of these resources as proposed in this vision may dictate future synchronization of these areas.

The result of this process is a 765 kV backbone system that provides cost-effective connections from areas of high wind potential to major load centers.

From a high level, this visionary concept would provide maximum access to wind resources throughout the country with cost and transmission reliability given appropriate consideration as well. Notably, connecting the study's target goal of 350 GW could be attainable with this plan, over time. While this is simply one of any number of designs that could be considered, it is believed that a national 765 kV plan of this approach would create a robust platform increasing access to renewable energy as well as facilitating a competitive energy marketplace.

Because the southeastern United States is deficient in significant, developable wind resources, no 765 kV lines have been proposed for that region. While transmission is needed both for connection of wind resources and delivery of the resources to load centers, it is expected that the 500 kV system in this area could be enhanced for power delivery. Although it still may be worthwhile to extend 765 kV into these areas, it was decided that the added line mileage and cost associated with delivering the wind resources should be the subject of additional study.

The scenario presented consists of approximately 19,000 miles of new 765 kV transmission lines. This mileage includes existing 765 kV project proposals, such as ETT's CREZ project in the ERCOT region and others in MISO and PJM. The rough cost of this plan is estimated to be $60 billion in 2007 dollars. This figure assumes a $2.6 million per mile 765 kV line cost, as well as an additional 20% for station integration, DC connections, and other related costs. These costs are ballpark estimates created without the benefit of detailed engineering and should be considered as such. Variations in labor, material, and right-of-way costs can cause these figures to fluctuate significantly.

There are considerable benefits

from a plan of this scale. First, it provides the most efficient method of interconnecting remotely located wind generation resources with a system that is capable of delivering such resources to the areas that need them. Today's aging and heavily loaded transmission system is inadequate for this purpose, especially on the scale that is required to meet new renewable energy goals. An added benefit is a significantly higher capacity and dependable transmission grid. Problems including congestion, aging infrastructure, and reliability that plague the existing transmission system will be alleviated. A 765 kV overlay adds considerable stability to the overall transmission system and reduces the burden on the lower voltage system. In addition, operational flexibility is enhanced to a large extent, especially when outages are required for maintenance on parallel or underlying facilities. This may also permit some obsolete portions of the system to be retired, upgraded, or replaced. Finally, this system provides access to a broader range of generation, facilitating competition that will ultimately reduce costs to consumers.

FROM VISION TO REALITY

When much of the existing transmission infrastructure was developed in the mid-20th century, predictions of today's electricity demand were a fraction of what has been realized. In addition, few at the time would have foreseen a carbon-constrained future.

There are undoubtedly significant challenges to overcome before such an aggressive plan could become a reality. Transmission expansion requires certainty of cost recovery for investors, which is often not the case, especially when crossing state, company, and operational boundaries. As with most transmission development, the significant right-of-way requirements of this vision may certainly delay and obstruct its formation. It is also difficult to advance from incremental transmission planning to a larger long-term, multi-purpose strategic plan that crosses jurisdictional and corporate boundaries. One of the singular difficulties with wind generation is the remote location of the resources.

Because of this, transmission and generation planning cannot be divorced from each other and limited to only few years in to the future, yet joint coordination of such requests is difficult and sometimes prohibited by regulatory edict. Steps in such a direction have been taken, but there is much more to be done.

Courtesy of the American Energy Producers (AEP)

A COOL WAY TO MONITOR HEAT

By Don Horne

Monitoring power cables is crucial to maintaining a clean, stable power supply – and keeping that stream of information concise and useful can be likened to separating the wheat from the chaff.

Many hundreds of miles of cable need to be constantly monitored by the utility every day; but that doesn't mean burying the monitoring operator with an avalanche of raw data.

Based out of Austin, Texas, SensorTran Inc. has come up with the Distributed Temperature Sensing (DTS) Calibration Module, providing oil and gas and electrical power companies with the first truly auto-correcting calibration for DTS.

"Auto-corrective calibration has always been seen as unachievable in the DTS industry, and we're proud to be the first to offer this critical capability," said Kent Kalar, CEO of SensorTran. "Our Calibration Module creates an auto-correcting DTS solution that requires minimal human intervention, even with portable systems that are connected to new probes all the time. This creates tremendous time and cost savings for our customers."

The module offers continuous verification of calibration and automatically adjusts itself when discrepancies are identified. It is the auto-correcting capability that provides huge cost savings by ensuring crews are free to concentrate on mission-critical tasks instead of resource intensive DTS deployments.

"We can take temperature measurements of up to 36 kilometres in half-metre increments, deploying the fiber in or near the transmission cable," says Kalar. "By getting these kind of accurate measurements, we can help the utility derate their power factor, allowing them to utilize their cables more efficiently."

The module creates a unique thermal profile with high and low temperature reference points that DTS units automatically recognize as being generated by the Calibration Module. The DTS unit uses these temperature reference points for accuracy

verification and auto-correcting the calibration of the DTS.

The origins of the DTS Calibration Module can be traced to space.

"It began when Lockheed Martin needed us to develop sensors to monitor the cryogenic fuel tanks inside the X-33 (the reusable space shuttle project that was cancelled by NASA in 2001)," says Kalar. "We took this technology and looked around to see where it could be applied elsewhere, and the electrical T&D market was a natural fit."

Providing 40,000 discrete temperature measurement points along the complete length of optical fiber, the DTS monitoring system provides real-time dynamic temperature data with high accuracy, fine resolution and fast measurement speeds.

"The fiber optic DTS method used the Raman-effect, which was developed at the beginning of the 1980s in England," says Kalar. "This is a proven technology in Europe, and it is only now being adopted in North America, with the Puerto Rico Power Authority, in Boston and with BC Hydro and in Edmonton, Alberta."

The fiber optic-based DTS method measures temperature using optical fiber instead of thermocouples or thermistors, as has typically been the case in the past.

Applications for the technology include:

Power Transmission Cables – dynamic temperature and health monitoring of long-range power transmission cables and joints including direct buried cable, cable tunnels and cable ducts. Additionally, provides installed data for input into real-time cable rating and ampacity calculation software.

Power Distribution Networks – real-time temperature and health monitoring for the optimization and health monitoring of entire power distribution networks. Ideally suited for direct buried, cable tunnels and cables installed within multiple cable ducts.

"The benefits for monitoring power cables are that it provides real-time dynamic temperature information along the full length of transmission cables and complete networks for load maximization and health monitoring, while identifying small hot spot locations and temperatures (joint health monitoring for example) with no need of prior knowledge," says Kalar.

"It provides accurate and actual temperature data for input into dynamic cable rating systems or calculations based on installed conditions, establishes cable thermal profiles and footprints and additional early fire detection in cable tunnels and ducts."

Fiber optic-based distributed temperature monitoring is of a particular advantage in several common situations:

• When there are a large number of sensors to be placed. If it is necessary to place a lot of temperature sensors for complete monitoring, then the ease of installation of fiber optic DTS becomes apparent. A single optical fiber can replace many point sensors, so all that is necessary is to route the fiber so that it provides the necessary measurement coverage and density.

• When there is no prior knowledge of sensor placement. When the preliminary engineering is performed on a project, it is not always possible to determine the correct location for temperature sensors. The high spatial resolution and long range of a fiber optic sensor allows the operator to select which parts of the fiber to monitor after the project is complete.

• When electrical temperature monitoring is impractical. In a situation where there is a large amount of electromagnetic noise, the data being read from thermocouples and thermistors can be corrupted. However, the data being read by the DTS is purely optical and thus immune to contamination in this kind of environment.

• When electrical temperature monitoring is unsafe. There is a risk of sparking inherent in all electrical systems. If the atmosphere in the area being monitored is in danger of becoming volatile, then the fact that a fiber optic DTS does not present a spark hazard can be a significant safety advantage.

But the true benefit of DTS technology is its ability to fit into the overall SCADA and smart technologies operated by the utility.

"We are simplifying the DTS hardware so you don't need specialized expertise to operate it within the substation and distribution monitoring systems," says Kalar.

And for smaller utilities, compatible and simple mean greater savings.

"For a big utility, it is easy – one system and one circuit. But for small utilities, they need one system that is portable and can monitor multiple circuits. It is crucial that we can work as a node within the SmartGrid. It needs to be an active plug-and-play technology."

FACTORS AFFECTING UNDERGROUND PLACEMENT OF TRANSMISSION FACILITIES

AEP's Operating Companies are occasionally asked to place sections of their transmission lines underground. (Transmission lines differ from distribution lines by virtue of their much higher voltage capacity – generally above 40,000 volts.) The reason given for such requests relates to aesthetics in most instances.

This article outlines the various factors that govern decisions about the placement of transmission lines and whether they are built overhead or underground.

BACKGROUND

Electric transmission facilities form the backbone of the bulk electric power network. Generally, power lines of 69 kilovolts (kV) to 765 kV are considered to be transmission level voltage. Underground transmission involves a construction technique that encapsulates the conductor in an insulating material before burying it beneath the ground surface.

Due to the different electrical characteristics of underground construction, the actual amount of power a buried line can carry is significantly lower than the amount of power an overhead line can deliver. Underground lines physically store a significant amount of electrical charge, which means that a larger portion of the line is required to carry the power flow. As a result, underground transmission lines must be relatively short or use expensive methods, like shunt compensation, to improve the flow of power.

Generally, underground transmission is used in urban areas due to the lack of usable rights of way for overhead transmission. Construction in this environment usually entails installations under sidewalks or under roadbeds. This increases the amount of labor needed to cut roads/sidewalks, trench, refill the trench and repair the surface.

To date, 500kV has been the highest voltage transmission cable successfully placed in underground operation worldwide. The highest in the U.S. is 400kV. A prototype PPP-insulated 765 kV HPFF (High Pressure Fluid Filled) cable system successfully completed long term qualification tests at the Electric Power Research Institute Waltz Mill Test Facility, but has not been commercially deployed as yet.

COST ISSUES

Underground cable system costs depend strongly upon the specific design and installation conditions. It is not appropriate to simply state a "standard" cost ratio of underground to overhead. Cost ratios have ranged from 1/1 (because of very expensive overhead construction in urban area, with many angle structures) to more than 20/1 (rural areas, inexpensive overhead construction).

Note that the ratio often depends more on the denominator (overhead costs, such as line construction) than the numerator. Underground cables are always going to be more expensive because every foot of the route must be excavated and restored. In some cases where the ratio has been low, the utility has been faced with acquiring extremely expensive right-of-way for the potential overhead line.

EVALUATING THE PROS AND CONS OF UNDERGROUND TRANSMISSION

Beyond the aesthetic value of underground transmission lines, typical forced outage rates are lower than those for overhead lines. This is because underground lines are not exposed to storms

Continued on Page 43

Underground transmission

Continued from Page 41

and trees.

However, the combined effects of forced outage rates and repair times must be taken into account when comparing the overall reliability or availability of both types of transmission. When this is done, the availability of overhead lines is typically higher than those for underground lines (see Table 1).

Although a narrower right of way is typically needed for underground transmission, the entire right of way must be cleared to allow access and visibility. Short growing vegetation is sometimes allowed in overhead rights of way.

Material lead times, especially the underground cable and splices, are significant. This is due generally to the low amount of demand and the ability of the manufacturer to gear up to a particular cable. This causes the utility to keep a significant amount of inventory in case of emergency or risk a multi-month circuit outage. Due to this fact, multiple redundancy is often built into underground circuits by laying parallel circuits for emergency, therefore, increasing cost.

	Overhead	Underground
Forced outage rate (outages/yr./mi.)	0.005	0.00165
Mean repair time (days)	0.375	21
Mean time between failures (yr.)	200	606
Unavailability (hours/year)	0.045	0.832

Table 1 – Typical Reliability Statistics for 138 kV HPFF Cable and 138 kV Overhead Lines

RELIABILITY ISSUES

Outages on underground transmission cables are primarily caused by dig-ins (i.e. cable damage due to excavation in the vicinity of the underground line). Consequently, the damaged cables must be located, and then exposed and time-consuming repairs must be completed before the cables can be returned to service. Typical repair times for underground transmission forced outages are one to three weeks or longer, months, in some cases.

Outside of physical damage due to excavations, underground splice failure is the leading source of transmission underground cable failures. Splicing is a labor intensive, manual process that joins segments of underground transmission cables. Besides introducing a source of electrical resistance, this connection point also increases the chance for moisture to migrate into the conductor allowing for an electrical short to occur.

Protecting underground systems is also a challenge. Because most cable faults are direct shorts (not induced by transients, i.e., lightning), reclosing on cables is rarely done automatically. This means that any protective equipment operation will lead to a sustained outage on the cable circuit until a comprehensive inspection is done of the visible parts of the cable or a non-destructive electrical test is done on the cable prior to returning power to the line.

As a result of the much longer repair times for underground transmission lines, it is relatively common practice to design cable circuits with 100 percent redundancy. That is, two parallel cable circuits are often installed with each of the two cables having sufficient capacity to carry the rated load of the circuit for the duration of contingency (typically the mean repair time). This obviously increases the cost of new transmission construction.

INSULATING UNDERGROUND CABLES

All power cables must be insulated from the ground to achieve meaningful power flow.

This is achieved by encapsulating the aluminum or copper power line with an insulator.

This insulator can take several forms; from fluids (most common, i.e., insulating oil) to solids (non-conducting dielectric polymer) to gas (sulfur hexafluoride - SF_6). Each has characteristic benefits and flaws.

There are significant differences in the maximum ampacity (current-carrying capacity in amperes) and power transfer ratings of the different types of transmission cables.

OIL/GAS-COOLED UNDERGROUND CABLES

High Pressure Fluid Filled (HPFF) underground transmission systems with system voltages of 69kV to 345kV have been in commercial operation for over 70 years. HPFF cable systems with rated

Continued on Page 45

DIGITAL CONTROL SYSTEMS FOR HIGH-VOLTAGE SUBSTATIONS - PART I

By James Propst, Western Area Power Administration (WAPA) and Mike Dood, Schweitzer Engineering Laboratories, Inc.

This article describes the design, implementation, and commissioning of a complete protection and control system retrofit project at a large transmission substation. Fort Thompson Substation, located in South Dakota, has two 345/230 kV step-down transformers with two 345 kV lines and twelve 230 kV lines. Western Area Power Administration (Western) undertook a project several years ago to completely renovate all the protection and control systems at this substation. They used the automation practices that Western had developed to reduce costs of new substation construction.

While it is easy to cost justify integrating and automating systems when building a new substation, it is traditionally more difficult to justify automation system upgrade schemes when doing a renovation project. However, recent innovations in the integration capabilities of microprocessor-based protective relays, and other substation IEDs, make a complete integration system upgrade, including automation, cost effective compared to selective replacement of individual IEDs, wiring, and testing.

This article describes the justification and special challenges of automating an existing substation.

It also discusses the overall system design concept of the integration and automation schemes that were employed. Topics covered in the article include:

• Extensive use of fiber-optic cables to replace all control wiring in the yard;

• Extensive use of multifunctional protection devices to eliminate wiring and equipment that would be required in a traditional design;

• Replacement of hardwired lockout relays with “soft” logic;

• Elimination of hardwired I/O to the RTU;

• Project management tools used to ensure completion dates and to maintain budget;

• Challenges of designing operator interface screens;

• Impact on the workforce in migrating to a completely automated substation;

• Insights gained in testing and commissioning the substation.

INTRODUCTION

Western Area Power Administration markets and delivers reliable, cost-based hydroelectric power and related services within a 15-state region of the central and western U.S. and is one of four power marketing administrations within the U.S. Department of Energy whose role it is to market and transmit electricity from multi-use water projects. Western’s transmission system carries electricity from 55 hydropower plants operated by the Bureau of Reclamation, U.S. Army Corps of Engineers, and the International Boundary and Water Commission. Together, these plants have a capacity of 10,600 megawatts.

Western started its automation projects with the goal of reducing the construction cost of new substations. Western estimated it could save 40 percent in building size and cost alone. Western also estimated similar savings could be realized in control panel costs with integrated digital controls.

Western began deploying programmable logic controller (PLC) control systems in 1996 with a pilot project at the Fort Thompson 230 kV yard. The pilot substation consisted of four 230 kV lines with a breaker-and-a-half bus arrangement. These initial designs replaced only the substation control wiring — no aspect of protection was included in the project. The PLC designs included an industrial computer running a Wonderware InTouch software application as the local operator’s monitoring and control system human-machine interface (HMI). After modifications to the original design, the PLC design became the standard and was deployed in 20 substations across Western’s service territory.

Western started looking at alternatives to the PLC design soon after these installations, and in 1998 they attended the open house and demonstration of the Philadelphia Electric Company (PECO) integrated system design. Meter and relay (M&R) mechanics at Western were not comfortable or confident with working on the PLCs and associated ladder logic, but they were comfortable working with microprocessor relays. Western also experienced PLC control failure associated with the use of the protocol interface to SCADA. Western felt that moving control functionality from the PLCs to a microprocessor relay and communications processor would address the reliability and comfort issues that the M&R employees had with PLCs. Eventually, Western chose the highly reliable combination of microprocessor relays and communications processors as their new digital control system (DCS) design to replace the PLC-based platform and chose to make Fort Thompson a pilot project. Once again, as was done with the PLC project years earlier, the pilot substation consisted of four 230 kV lines with a breaker-and-a-half bus arrangement.

In the conversion from the PLC control system to the DCS design, Western also decided to include protective elements, or lockouts, in the DCS design. One lesson learned from the PLC design was that mixing digital and hardwired logic adds complexity to both portions. Because of the design and manufacturing processes, typical MTBF, and environmental ratings of PLCs, Western was not comfortable placing any protective functions in the PLC. Because the DCS would use protective relays for control, it seemed natural to have the lockout func-

Continued on Page 48

Underground transmission

Continued from Page 43

system voltages up to and including 765kV are commercially available and have passed long-term qualification tests.

High Pressure Gas filled (HPGF), is similar in construction but the dielectric fluid is replaced by 200 psig nitrogen. HPGF cable systems are not commercially available for system voltages above 138kV.

Gas Insulated Transmission Lines (GIL) have been used in applications where high power transfer capabilities are required, such as short dips in overhead lines or relatively short substation connections to overhead lines. GIL generally utilizes SF6 gas as the insulating medium.

Compressed-Gas transmission cables have significantly higher ampacity ratings (5 kA and higher) than the other cable system types because:

1. The relatively low insulating strength of gases (compared to solid and laminar fluid filled electrical insulations) means that the diameters of the high voltage conductor and aluminum enclosure must be large. Therefore, the current ratings are also large because of the large cross section of the high voltage conductor and enclosure.

2. Dielectric losses, which are losses of energy that cause a rise in the temperature of the gases (nitrogen and SF6), are extremely low compared to most solid and laminar insulating materials. As a result, compressed-gas cables have increased ampacity ratings.

Self-cooled HPFF and HPGF transmission cable systems with very large conductors (3,500 thousand circular mills - kcmil) typically have power transfer capabilities of 1,200 amperes or less, which is significantly less than self-contained, fluid-filled (SCFF) cable systems. This is due to the following reasons:

1. Magnetic losses in the magnetic steel pipe, like eddy current and hysteresis, are comparable to the losses caused by heat in the high-voltage conductors. The pipe losses significantly decrease the ampacity rating of the cables inside of the pipe.

2. Losses of energy, resulting in the rise in heat of laminar, fluid-impregnated insulation are significantly higher than for XLPE extruded dielectric insulation.

DIELECTRIC (NON-CONDUCTING) POLYMERS

The first major domestic 345kV solid dielectric transmission systems were installed in Connecticut, Long Island and Chicago in the past several years. Elsewhere, hundreds of miles of 230 kV solid dielectric cable systems have been installed in numerous countries around the world and tens of miles of 400 kV solid dielectric cables have been installed in Europe. Japan completed installation of the first sizeable (two circuits, 25 miles long) 500 kV cross-linked polyethylene (XLPE) transmission cable system in late 2000.

XLPE-insulated cables have a significantly higher power transfer capability than pipetype systems because of the lower dielectric losses, absence of pipe losses, and greater separation among phases. Large conductor size cables can have ratings greater than 2000 amperes.

The ampacity rating of XLPE transmission cables are higher compared to the same conductor size SCFF cable system because of the lower dielectric losses and charging current of the XLPE cables.

SUMMARY CONCLUSIONS

- The cost to place transmission facilities underground is, at a minimum, 2-3 times more than the comparable overhead option. In some situations, the cost difference can be 10 times more.
- Utility commissions typically allow electric utilities to include in the rates charged to all its customers, only the reasonable costs of facilities necessary to provide safe and reliable service. In most cases, this would be the cost of overhead lines. Thus, unless there are extenuating circumstances that dictate the use of underground facilities in lieu of overhead facilities, AEP would not be able to recover the premium paid to place facilities underground.
- The time and cost required to isolate and repair a problem with underground transmission lines is normally much greater than for overhead lines. Circuit outage times will almost always be greater, too, thus raising the reliability risk of operating the system without all lines in service, and raising the potential for customer dissatisfaction with lengthy outages.
- Underground transmission lines pose a significant safety hazard to non-electric utility construction personnel who do not follow proper protocols/laws /rules and accidentally dig into these lines.

ADDRESSING CLIMATE CHANGE CHALLENGES THROUGH NUCLEAR TECHNOLOGY

By Kevin Routledge, President of AMEC NCL

With the continued commitment of the Ontario government to eventually phase out the coal plants as part of their green energy plan, and with climate change moving to the top of the political agenda worldwide, carbon free options, including nuclear energy, will become even more important for meeting the growing energy demands of the province.

In Canada, nuclear power accounts for 15.5 per cent of the electricity mix, and provides 54 per cent of Ontario's electricity sources. However, Ontario's nuclear plants are aging, and many will be in need of refurbishment over the next decade. If these aging nuclear plants are not refurbished, Ontario will be left with only 5,900 MW of nuclear capacity by 2015 – only a small fraction of what will be needed; and with large scale options, such as gas fired plants, subject to price volatility, the fuel required for this will likely be in scarce supply.

In October 2005, Bruce Power, Ontario's second largest utility, awarded AMEC a contract to project manage the restart of two of its nuclear reactors, Units 1 and 2, at its Bruce A power station. Bruce Power, which is located on the shore of Lake Huron, is home to eight CANDU pressurized heavy water reactors. Units 1 and 2 were shutdown in the mid-1990s when the then owner Ontario Hydro decided to concentrate resources on operating its other reactors. The enormous significance of this project can be seen in the investment required to bring the Units on line again. The project is estimated to cost C$2.75 billion (US$2.43 billion), funded by the private sector, and is expected to be complete in 2009.

AMEC is providing project, contract and construction management for this highly complex project, as well as engineering acceptance, and the health, safety and environmental programs and oversight. Currently, the project has over 2,000 staff, working both on and offsite, which is near the peak of workers expected during the project.

The restart project is one of the largest and most challeng-

ing engineering projects to take place in North America. The project requires a series of refurbishments, upgrades and enhancements to the two reactors. The work includes:

The replacement of reactor's pressure tubes and calandria tubes (480 in each reactor);

Replacements of half the length of feeder pipes, which provide water to the fuel channels;

Steam generator replacements (8-110 t vessels in each unit);

Electrical systems upgrades;

Main condenser refurbishment;

Turbine refurbishment;

Feed water heater refurbishment;

Shutdown system 2 (SDS2) enhancement; and

Significant other maintenance on both nuclear and other plant equipment.

For the remainder of the plant, the opportunity is being taken to upgrade and enhance other nuclear and non-nuclear systems. For example, 30 transformers in the two units contain polychlorinated biphenyls (PCBs). These will be removed and replaced with non-PCB transformers.

After both nuclear and non-nuclear systems have been refurbished and upgraded, Bruce Power will request permission to refuel Units 1 and 2 from the Canadian Nuclear Safety Commission. During refueling, the reactor will be loaded with natural uranium fuel, except for a small number of depleted uranium fuel bundles, used to fine-tune reactivity in the fresh core, at specific locations. Each reactor will require 576 22.5 kg fuel bundles or approximately 260 t of fuel for the initial refueling.

From a physical standpoint, this project is extremely challenging, but this project is also demanding from a regulatory standpoint. Refueling will require a license amendment enabling Bruce Power to move the reactors from a safely-laid up state to a guaranteed shutdown state. Refueling and associated operations such as refilling the primary heat transport system, final system integration, and commissioning will precede synchronization to the power grid by approximately five months.

The overall aim is to improve the safety of the reactors, and to increase potential generation capacity and reliability. Completion of the project will enable each Unit to produce safe, economical power for an additional 25 years.

Since the project commenced on October 31, 2005, the project continues to schedule, and has achieved the following milestones:

The environmental assessment was approved, without any negative interventions;

An offsite training facility has been set up and operated, with, to date, over 3500 workers trained in project processes, prior to them starting work on site;

Major offices and warehousing facilities are in place;

A construction island has been created around Units 1 and 2, with separate processes and procedures from the operating units;

Both Units has been fully isolated from the other units, and decontaminated; with work at the reactor face in Unit 2 already able to be undertaken in "civvies";

Feeders in Unit 2 have been removed and progress is well in hand for removal of the fuel channels; and,

Ten of the 16 new stream generators have arrived on site and four are now installed.

Safety is of paramount importance on this project, and, to date, over 5 million hours have been worked on site without a lost time incident. In addition doses to workers are well below budgets, as is the radioactive waste being dealt with on the project. Environmental impacts from the construction work have been minimal.

In addition to AMEC, there are other well known Canadian companies involved with this project including Atomic Energy of Canada Limited (AECL) , who is replacing the fuel channels of the reactors; Babcock and Wilcox, who is supplying the steam generators and installed bulkhead plates to isolate the units; SNC Lavalin, who is removing and installing the new steam generators; Siemens Canada, who is responsible for refurbishing the turbines and the electrical systems; and Acres/Sargent Lundy, E S Fox, RCM Technologies, General Electric of Canada, and Ontario Power Generation, on the balance of the work.

Though refurbishments can be completed faster, and the costs are less than building a new nuclear power station, legacy issues and proximity to the operating Units, make it more complex. The task of removing steam generators, as well as pressure tubes, calandria tubes and feeder pipes at the same time significantly increases the challenge, particularly as a number of these evolutions are first of a kind in the industry.

The Bruce A restart is just the first stage of a much broader C$4.25 billion (US$3.76 billion) program to extend the life of the station planned by Bruce Power. With increasing demand, and aging assets, the success of the Bruce A restart is critical to securing Ontario's energy future.

With the Bruce A restart project now well advanced and on schedule, this project will ensure nuclear power continues to play a key role in a diverse energy strategy for Ontario.

Kevin Routledge is President of AMEC NCL, the nuclear division of AMEC in North America, and was until very recently the Project Director for the Bruce Restart project. For more info contact kevin.routledge@amec.com

Continued from Page 44

tion reside there as well. Western chose a single dedicated microprocessor breaker failure relay as the "input" point to the DCS system. The outputs from the DCS system used contacts from the breaker failure relay and one of the line relays to provide a redundant control path for the power circuit breakers. Communications processors were used in the design to provide the interface to SCADA and the local HMI.

Although this initial DCS design was a step in the right direction, it was apparent that an additional iteration in the design would be required to provide enhanced economy and simplicity.

The next iteration was the use of fiber-optic cable to replace copper communications and the relocation of the DCS system inputs to be field I/O devices mounted near the station apparatus rather than duplicate the inputs with parallel copper wiring to the centralized IED. Thus, integrated digital communications allowed the I/O of the IEDs to be used for several functions within the DCS. A single 52a contact from the breaker auxiliary stack, wired to a remote I/O device, was used to provide this status for the entire system, including the protective functions.

Alarm points were wired only into the I/O device at the equipment, instead of also being separately wired to the control building and connected to an RTU.

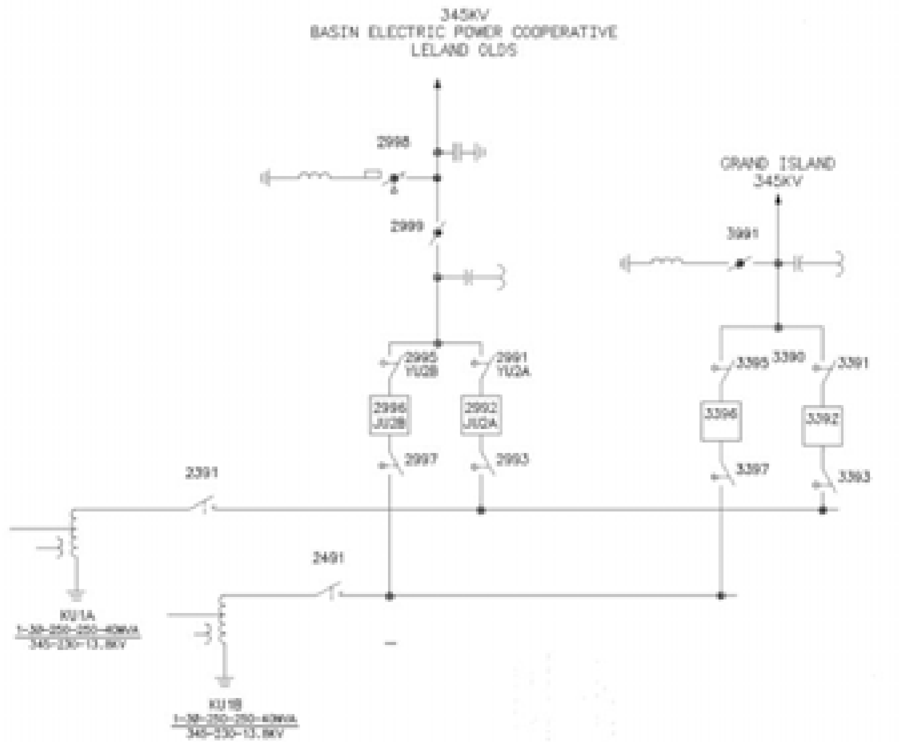


Figure 1. Fort Thompson 345 kV yard bus arrangement after Stage 06 modifications were completed. Four 345 kV circuit breakers, three 13.8 kV reactor breakers, eleven 345 kV MODs, and two 345 kV interrupters are under DCS control.

PROJECT DEFINITION

Fort Thompson 345 kV Yard

Operations determined that the 345/230 kV transformers in the 345 kV yard should be separated from a common bus, creating a four-position ring bus configuration. This work required the addition of a 345 kV breaker and required modifying the bus work. The substation controls and relaying were largely original equipment from the 1960s. Western decided to replace the control panels because extensive wiring changes were needed to bring the substation up to current Western standards for SCADA.

The substation was built on expansive soils, which tend to move considerably, and which caused the foundation for the control building to crack in half. As the two halves settled, a three-inch crack developed in the wall, which had been covered with a steel plate to keep the birds out.

These problems made fixing the building impractical, so it was replaced with a modular, energy efficient, low-maintenance building. The design of a DCS using integrated relays allowed the building to be over 40 percent smaller because integrated systems are much smaller than conventional PLC and RTU control designs.

The expansive soils over the years had created shifting in the control cable trays, causing the covers to have gaps. These gaps allowed rodents to enter the cable tray, causing substantial damage to control cable jackets. Unjacketed cable was eaten bare in many spots. The joint owner of the substation equipment agreed the control cable should also be replaced.

Fiber-Optic Cable

Fort Thompson, like most 345 kV substations, is a large substation. Cable lengths up to 1,000 feet were to be replaced. At the time of this project, 12/C #10 shielded cable cost about $2/foot.

Because the project would require about 17,000 feet of 12/C cable, the use of fiber-optic cable was considered as an option. Western determined that they could replace the 17,000 feet of 12/C copper with 2,700 feet of fiber-optic cable. The cost of 24-fiber cable at the time of the project was $1.84/foot. This represented an upfront savings of $29,000, which would be spent on additional hardware requirements for the use of fiber-optic cable. The concept up front was to show fiber was competitive with copper in the substation.

The fiber-optic cable would be installed to each circuit breaker, transformer, and reactor. Motoroperated disconnect (MOD) controls and inputs would be wired over copper cable from the MOD to the associated circuit breaker where a remote I/O device would be installed to accommodate both MODs associated with the circuit breaker. At the transformers, alarms and trips from sudden pressure, winding temperature, and low oil would be connected to the remote I/O device and brought to the control house over fiber. Coupling the MOD and MOI controls with the major equipment would save fiber terminations. Considerable amount of copper cable would be saved because the MODs were close to the circuit breaker, eliminating up to a 1,000 feet of 12/C for each MOD from the control house.

The use of fiber-optic cable would allow the digital inputs to be input into the DCS at the equipment. Western estimated that at least 75 percent of the DC wire terminations were eliminated. Consider that a cable must be terminated on each end, in this case to a terminal block in the building, then to a terminal block in the RTU, and finally to the RTU. This would all be replaced with a single switchboard wire at the individual piece of equipment.

About this same time, the logic processor became available on the market. This device allows the digital inputs to be distributed in real time among the relays and provides SOE (sequence-ofevent) information for the RTU. The logic processor allowed a single 52a contact from the breaker to be distributed digitally over communications links to the primary relay, secondary relay, breaker failure relay, and the RTU. This further diminished the required wiring terminations.

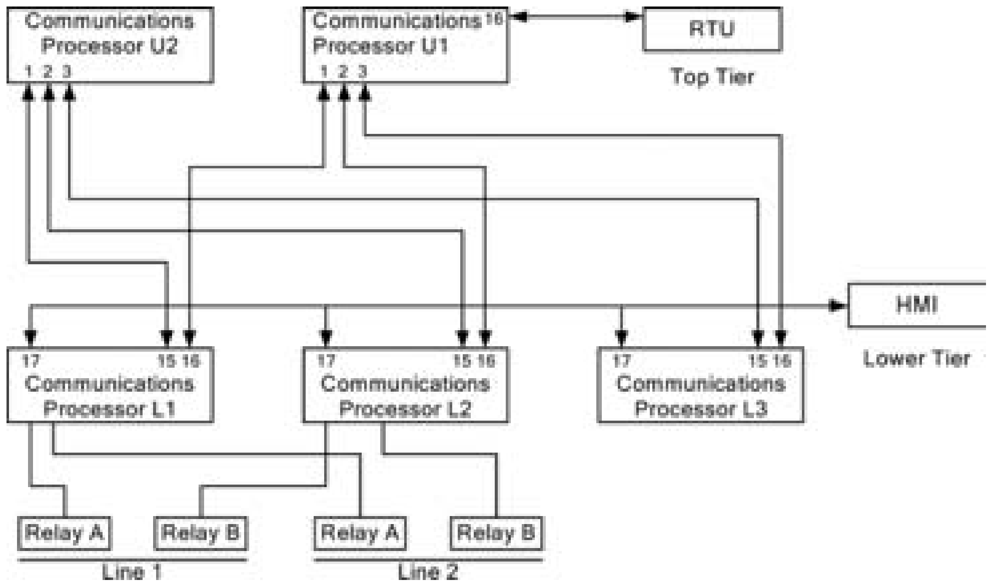


Figure 2. Communications Processor Architecture

The logic processor would also be used to create an extended digital protection system that tied all the individual pieces of equipment together to create an extended integrated protection system.

Because the logic processor would be used for SOE information, it needed to receive the digital relay operate event. This same piece of information would be sent to the breaker failure relay to initiate breaker failure. The use of the logic processor would eliminate the long block closing strings and breaker failure initiate wiring. All of this hardwired logic would be replaced with EIA-232 cables and settings.

Past Functionality

From the very first pilot project, Western had a high level of information flow with operations personnel, and they provided the manufacturer with feedback on their operational requirements.

Redundant controls were established as a requirement, as there was a concern about the ability to respond to and correct equipment failures with the new design. For the same reason, redundant HMI computers with redundant power supplies and hard drives running (Redundant Array of Independent Drives) RAID 1 controllers were used. The new center of the system, the communications processor, had Modbus Plus protocol available, so Western's previous HMI design modules, also based on this protocol in the PLC, were used with very little modification.

Good Site

Fort Thompson was deemed a good site for this project, because it was relatively small. A total of 7 breakers and 13 switches would be placed under DCS control. This would require fiber to be installed to 11 pieces of equipment — a very manageable number. The physical size of the yard made the fiber attractive, because a lot of copper cable could be eliminated. And, finally, the project had strong support from Western's Communications division, which installed and terminated the fiber-optic cable.

THE DCS DESIGN

Controls

Western operations personnel wanted the ability to trip and close a circuit breaker in the event of equipment failure. Therefore, Western designed redundant controls as a standard part of the automation design to eliminate single points of failure. The redundant control paths were accomplished using a two-tiered communications processor approach. The top-tier communications processor receives the SCADA command and distributes it via global data over the Modbus Plus network to the lower-tier communications processor. This creates a single point of failure for SCADA with the top-tier communications processor, but with an MTBF of greater than 200 years, this risk was accepted and is far better than single or redundant RTUs.

From the lower-tier communications processors, controls were passed to the individual protective relays. From the protective relays, positive, negative, trip 1, trip 2, and close were hardwired with a 5/C to the circuit breaker. Most circuit breaker protective trips were hardwired from the protective relays. Some of the bus protection trips were accomplished with relay-to-relay communication via the logic processor. In this design, the Set A protective relay and individual breaker failure relay provided the redundant control paths for the 345 kV circuit breakers. The individual breaker failure relay also directly controlled operation for the MODs adjacent to the circuit breaker via fiber-optic cable.

Eleven MODs and two motor-operated interrupter (MOI) controls were included in the design.

Only DC power was run to the MODs; control is accomplished using the remote I/O devices connected to the fiber-optic cable. Open/close commands are sent via fiber from the individual breaker failure relays to the remote I/O devices.

Reclosing, hot-line orders (HLO), synchronizing, and local/supervisory statuses for the individual power circuit breakers are maintained with latch bits in the individual relays. The latch bits are used in the internal logic of the protective relays to obtain the control functionality.

The HMI control actions are sent to the lower-tier communications processor via the Modbus Plus network. This design allowed for the failure of any one box while still maintaining local control.

Figure 3. The I/O device on the right provides open and close commands for the MODs. It also provides the 43LR, 52a, and 52b status to the DCS. The I/O device on the left provides inputs into the DCS for the individual power circuit breakers. Note the extra fiber-optic cable, which allowed terminations to be completed in a mobile van and provided additional cable for when the power circuit breaker is replaced.

SUBSTATION COMPUTER

Hardware Design

Western has used Wonderware as the HMI in their digital designs for several years. Due to the very limited knowledge of this software and computers in general in the workforce and the associated concern over the ability to respond to equipment failure, Western chose an industrial PC. Western purchased redundant PCs with hot-swappable redundant power supplies and hotswappable redundant hard drives. The hard drives use a SCSI RAID 1 controller to mirror the drives. The PCs are rack mounted in the control panel. To provide isolation to transients and to power the PCs, Western installed redundant DC-AC inverters that are normally fed from AC but switch to DC upon loss of AC. The inverters served as a universal power supply, because they switch supply sources without causing any disruption in the PC. A keyboard, video, mouse (KVM) device switches the PCs to a single set of LCD displays, keyboard, and mouse.

HMI Application Design

Western uses a dual display for the HMI. The left screen displays the station one-line with status.

They also use the buttons on the left screen to fill in the variables in the right screen template used for PCB control. The buttons rise when the cursor is placed over them. The 43LS, 79, and 85 statuses are shown directly on the screen. The 43LR, 52a, and 52b drive the color of the breaker status. When the 43LR is in the local position in the circuit breaker, the breaker status box is gray, with an M for "Maintenance" indication independent of the breaker position. The circuit breaker closed indication is red — open is green.

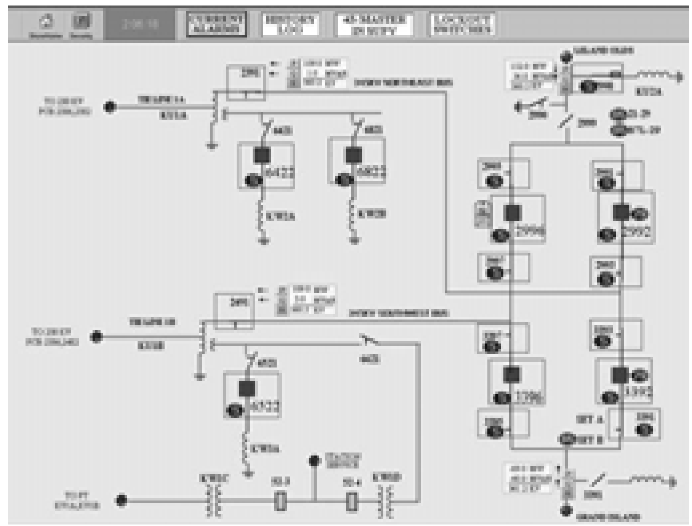


Figure 4. Left Fort Thompson 345 kV yard HMI display. The power flow indication and quantity for the transformers is obtained from adding the individual breaker failure relays.
Note the HLO tag on 2996.

Western's Power System Clearance procedures detail two primary tagging procedures — one for HLO and one for clearances. Western does not tag equipment controls under clearance with power system clearance tags. The only tag included in the HMI was for hot-line orders. The HLO tag indicates reclosing has been turned off and the circuit breaker close path has been interrupted.

Within the HMI, the HLO tag cannot be turned on when reclosing is in place. The HLO is represented on the one-line screen by a yellow HLO tag and flashing indication on the PCB control screen. If the close function is selected, an HLO WARNING screen is displayed, and closing is prevented.

The PCB control screen has a representation of a physical switch for each function. The switch representation was chosen to make the HMI intuitive. The PCB control screen is the same for all equipment, with only the appropriate functions visible and active. For example, the 85 function is disabled for dedicated transformer breaker, or reclosing for a reactor breaker is disabled. The HMI works by sending the command to the protective relays and then reading the status back via the communications processor to effect changes on the HMI displays. The switch handles rotate and lights change to indicate the appropriate status on the PCB control screen.

See the October issue of Electricity Today for Part II

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