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Outage/Vegetation Management & Storm Restoration

Protecting assets from harm through proper vegetation management

Stormy Weather: Intelligent Undergrounding Supports System Reliability and Resiliency

By Damien Polansky and Brent Richardson

'Be Prepared' certainly has grown beyond the purview of the Boy Scout motto. Being prepared is at the heart of the ability to anticipate unexpected events, know what you intend to do to survive or mitigate risk from that event, and how quickly you can bounce back. In a word, *resiliency*. The same view that we employ on an individual level pertains to the infrastructure that supports our daily lives. This has become painfully clear during the last decade as we've experienced unprecedented weather events that have displaced people and disrupted economies. Whether you believe that climate change is a result of human-kind's poor stewardship of the earth or that it is simply a cyclical event that happens naturally every few thousand years, we are feeling the effects. When it comes to power systems we have to think beyond the cleanup. We need to come together as an industry to plan for system resiliency, not just reliability under normal operating circumstances. Intelligent Undergrounding – the concept of burying transmission and distribution lines where it makes sense – supports both reliability and resiliency.

In its November 2013 report, *Resilience in Regulated Utilities*, The National Association of Regulatory Utility Commissioners (NARUC) defined resilience as 'Robustness and recovery characteristics of utility infrastructure and operations, which avoid or minimize interruptions of service during an extraordinary and hazardous event.' The report went on to state that "If an investment avoids or minimizes service interruptions in the absence of an extraordinary event, it's just an everyday reliability investment… resilient infrastructure does more than one thing well, because a resilience investment needs to pay for itself and create value for ratepayers, even when it's not being used." In other words, whether we're talking about a local storm that affects thousands or a catastrophic event that affects millions, we need to proactively consider investments in new or rehabilitated infrastructure that effectively builds in resiliency from the start, not just as part of post-event restoration.

The Case for Intelligent Undergrounding

In an op-ed article for the *Wall Street Journal, In Sandy's Wake*, *Time to Upgrade the Power Grid*, former New York Governor, George Pataki, offered that "To make our electrical grid more reliable, serious consideration has to be given to burying electrical distribution networks underground. This costly but critical investment would eliminate the need for utility poles and overhead wires, drastically reducing the need for repairs caused by wind and tree damage." He went on to further argue that "Another priority should be to harden and modernize the transmission systems that carry high-voltage electricity from large power plants down to the local distribution level."

The entire value chain, from compound suppliers, accessory component producers to cable makers, installers and utilities, has a vested interest in improving electrical system reliability and resiliency. Undergrounding distribution and transmission networks can and should be considered as part of the solution. While it's a fact that high-voltage underground transmission installations typically have higher up-front price tags than overhead lines (OHL), new trenching methods along with technologies that create more reliable, long-life cables, are helping to move costs to a more equitable position with OHL. This is where the concept of Intelligent Undergrounding comes into play.

Beyond advantages in securing rights of way or improving aesthetics and property values, the case for undergrounding jumps to the forefront when considered in the light of storm outages and subsequent system restoration. Urban areas can be particularly vulnerable when seen in the light of lessons from Superstorm Sandy, Hurricane Irene and last winter's polar vortices. Similarly, although affecting fewer ratepayers, weather-related outages in rural areas can bring homes and businesses to a standstill. It's clear that systems supported primarily by overhead lines and utility poles are much more susceptible to failure due to high winds, heavy snow and ice.

Across North America, we see more instances in both rural and urban environments where utilities, regulators and planners are working together to improve reliability in their regions. A noteworthy example was recently cited in the July 2014 issue of *Transmission & Distribution World* in an article that showcased the cooperation between San Diego Gas & Electric and the City of San Diego in undergrounding 75 percent of San Diego's power lines since 2003 – with plans "to underground approximately 1,000 miles of remaining overhead." The article went on to note that "Undergrounding reduces the possibility of power lines being affected by car accidents, high winds during storms and other adverse factors. This strengthens the infrastructure of the region's electric power system in order to further promote reliability and make the system more resilient under a variety of operating conditions."

Who Foots the Bill?

Cost recovery remains a hot topic when contemplating both necessary and preemptive investment in power systems. Further complicating matters is that there is currently no clear precedent on who pays – the ratepayer, the utility/service provider, the government or a combination of all of them.

ITC Holdings Group recently released a white paper *The Economic Case for Grid Investment* that includes research findings from a survey of 800 U.S. adults and in-depth interviews with business leaders at Fortune 500 and mid-size companies and economic development organizations. Ninety-three percent of those surveyed felt that "investing in the electricity transmission grid will ensure reliable access to power, especially during severe storms, for consumers and businesses." However, as the white paper acknowledges, "Despite agreement around the benefits of investing in the grid, Americans are divided over who is primarily responsible for actually investing in it. More than half (56%) say either federal (Congress) or local/state government is responsible for investing in the grid, while a quarter say electric utility companies are. Small percentages think that President Obama, consumers or private investors are responsible."

A recent Grid Resiliency Survey conducted by GE's Digital Energy business found that of the 2,000 adults surveyed, *41 percent of Americans living east of the Mississippi River are more willing to pay an additional $10 per month to ensure the grid is more reliable*. The survey noted that those living east of the Mississippi experienced three times more power outages than those living west of the Mississippi. As quoted in a news release from GE summarizing the survey, John McDonald, director of technical strategy and policy development for GE's Digital Energy business offered, "The survey results are an indicator that consumers want to invest in technology to prevent power outages and reduce the time it takes their local utility to restore power." This sentiment is echoed, especially in the Midwest, Northeast and Atlantic coast regions most recently affected by severe weather events. Other sources indicate that Americans are willing to pay between $4 and $40 more per month per household to aid in both cost recovery efforts for grid restoration and for investment in new or improved infrastructure that is better equipped to maintain reliable operation or more quickly recover under adverse conditions.

Federal funding is more problematic. As further supported in George Pataki's *Wall Street Journal* article, "…the way the Federal Emergency Management Agency works with electrical utilities after disasters needs reform. Under the current system, utilities receive federal emergency funding to replace damaged electrical components only if they replace them 'in kind' with the same technology. This means that all sorts of antiquated components are simply being replaced. This makes no sense. The federal government should promote modern technologies and best practices."

Experts from Ernst & Young Power & Utilities Advisory Practice throw the baton back to utilities. In an article from May 2014's Powergrid International, these experts state that "Given today's challenging regulatory environment, utilities should develop a storm response plan to optimize the likelihood of cost recovery. The time to consider planning for storm recovery begins well before any storm."

While a comprehensive storm response plan will help restore power more quickly, the goal should be to prevent the power from going out. Understanding key elements of the grid and knowing which elements are most vulnerable – then proactively upgrading them – will reduce the number of outages. The principles of Intelligent Undergrounding offer proven ways to reduce storm related outages and improve the resiliency of the grid.

With all this being said, when it comes to investing in resilient systems, consideration needs to be given to total lifetime system cost. Quality-made underground cables can deliver 40+ years of service with less likelihood of failure or ongoing maintenance costs normally associated with OHL. So, for whatever combination of parties that ultimately foots the bill, the potential return on investment for undergrounding appears quite attractive.

Quality Materials Matter

Cable compound suppliers are a critical part of the value chain in the power industry and can have a huge impact on power system reliability. Cable manufacturers and utilities have many choices when it comes to specifying materials to manufacture cables. Years of experience and data from independent testing institutes indicate that cross-linked polyethylene (XLPE) for high-voltage transmission and tree-retardant XLPE (TR-XLPE) for medium-voltage distribution underground cables continue to provide the best performance for robust manufacturing, ease of installation and high electrical breakdown strength that ensures failure-free operation and lower electrical losses over the lifetime of the cable. Compound suppliers also recommend a systems approach when considering cable construction. Highly-engineered insulation, jacketing and semiconductive compounds are designed to work together for the best result. Quality materials made to meet or exceed stringent industry standards are key to long-life, reliable cables that extend that reliability and resiliency to the underground systems in which they are placed.

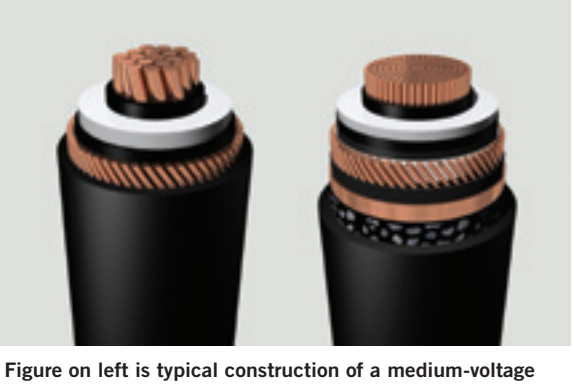

Figure on left is typical construction of a medium-voltage underground cable utilizing TR-XLPE solid insulation. Figure on right is typical construction of a high-voltage underground cable with PE-based jacketing and semiconductive layers and super-clean XLPE solid insulation.

High-voltage underground cable installation (photo courtesy of Southwire)

Investing for the Future

Perhaps songwriters Burton Lane and Alan Jay Lerner said it best in the play and song of the same name: "On a clear day you can see forever." It's true. In a clear skies scenario, maintaining reliability in power systems during normal everyday operating conditions is hitting the mark. However, planning ahead to invest in system resiliency that is required to prevent or quickly recover from outages caused by stormy weather is expensive but essential. Intelligent Undergrounding needs to be part of that solution. The time has come for the industry value chain to share best practices, factoring in total system lifetime costs based on increasing reliability and resiliency. This does not mean that there isn't a place for overhead lines – it just means that underground and overhead can be planned and installed together in a way that makes sense to best serve businesses and communities that rely on power at every flip of a switch or push of a button, even under adverse conditions.

No matter what side of the fence you're on concerning climate change, Paul Mauldin in a recent post in *Transmission & Distribution World's The Grid Optimization Blog*, aptly stated that "The silver lining in climate change hysteria is this: we can expect accelerated adoption of new methodologies and technologies which will improve service even between storms."

That's the target we're all aiming for. Proactive improvement and hardening of power systems is the right thing to do. Power supports economies. Power ensures the connectivity that is essential to human progress. Value chain partners working together to invest in a common desirable outcome will reap the reward of trust and satisfaction from power consuming customers – along with resiliency for the grid and for our businesses.

About the author

Damien Polansky is Global Strategic Marketing Director Dow Electrical & Telecommunications (Dow E&T), a business unit of The Dow Chemical Company. In this role Damien is responsible for creating and driving the long-term strategic vision of Dow's participation in the electrical transmission and distribution industry. Since joining Dow in 1997, Damien has worked for Dow in several business units across many functions including manufacturing, technical service, Six Sigma Blackbelt, sales, and marketing. Damien holds a Bachelor of Science degree in Chemical Engineering from the University of Texas at Austin and an MBA from the University of Notre Dame.

In this role as North American Manager of End Use Marketing, **Brent Richardson** represents Dow's Electrical & Telecommunications business to the utility industry in North America. Prior to joining Dow in May of 2007, Brent worked for nearly 25 years for Duke Energy in Charlotte, NC. His experience includes many components of the utility business including Field Engineering, Distribution Standards, Project and Product Management and Marketing. He received a BS in Electrical Engineering from Virginia Tech and is a registered Professional Engineer in NC and SC. He is also a voting member of IEEE Power and Energy Society and the ICC and has written and presented numerous papers to the IEEE, the ICC and other industry groups. Brent serves as Vice Chair of the ICC A14D – Cable Standards subcommittee.

Mitigating Damage from Extreme Weather

By Dan Zapotok

Since the August 2003 blackout in the Northeast, electrical grid reliability has been under heavy scrutiny. Circumstances leading up to that massive power outage – as well as other modern-day blackouts in the United States – have been thoroughly examined. While many factors contributed to the power interruptions, severe weather has been cited as the single leading cause. And major weather events are becoming more common.

A report released in August 2013 by the Executive Office of the President of the United States estimated 679 widespread power outages due to extreme weather events occurred between 2003 and 2012.[1] The report cites a heavy financial toll from those weather-related outages, with cost estimates ranging from an annual average of $18 billion to $33 billion. A recent Congressional Research Service study cited in the report estimated annual average weather-related outage costs at $25 billion to $70 billion. Cost variations were attributed to the assumptions and data used for calculations.

The report also cited data from the U.S. Energy Information Administration, which described a significant increase in weather-related outages since 1992. The National Climate Assessment foresees the incidence and severity of extreme weather continuing to escalate due to climate change. While the effects of these changing weather patterns are predicted to vary throughout the country, projections include more frequent heavy precipitation events, more extreme temperatures, increased hurricane intensity and stronger, more frequent winter storms.

Vegetation management along utility rights of way can play a key role in minimizing the effects of extreme weather events. As utility companies across the country work to prevent and mitigate storm damage and outages, they are employing innovative, efficient vegetation management programs to provide long-lasting solutions that protect electrical transmission and distribution lines from vegetation-related outages.

Drought, Winds Alter Work Patterns

Southwest Ground Control in Chandler, Arizona, handles vegetation control on utility substations and transmission line rights of way (ROW) throughout the state for Arizona Public Service. Company crews cover 12,000 miles (19,300 kilometers) of transmission line ROW and substations and provide landscape maintenance and other site services for utility buildings and power plants.

In 2008, Arizona Public Service undertook a massive ROW maintenance program to help increase transmission reliability and comply with Federal Energy Regulatory Commission (FERC) and North American Electric Reliability Corporation (NERC) standards. The project includes tall brush mowing followed by a sustainable herbicide maintenance program.

Timing Applications with Rain

"We move crews with the weather and plan applications for when we have a good chance of rain for herbicide incorporation," says Ron Romero, owner, Southwest Ground Control. "We seem to be having a longer break between rains in recent years. And the rain we receive falls in larger doses than in the past. Rather than four quarter-inch (±7 millimeter) rains, we'll get a single one-inch (±25 millimeter) rain."

Extremely dry conditions in parts of Arizona have led to strict treatment mandates to prevent the spread of wildfires. These limitations greatly affect crew productivity and interrupt schedules.

"When the Forest Service issues red-flag fire warnings, tree-cutting and application crews can't run any gas-powered machines after 9 a.m., and a crew member must stay on treated sites for three hours," Romero notes. "When wind speeds reach 20 to 30 miles per hour (32 to 48 km/h), our crews are completely shut down, and we're quickly behind schedule."

Customized Solutions

To meet Arizona's exacting standards for an environmentally favorable, sustainable program, Romero implemented a treatment program that features a preblended herbicide tank mixture delivered in a returnable, reusable container system. The containers include a bar code for easy tracking from the blending facility to the field.

"The herbicide mixture is specifically blended to match the brush being treated," Romero says. "And the premix eliminates mixing errors in the field, helping our crews apply the same mixture consistently. Because we use an ultra-low volume, four operators can work at extremely remote sites for a week, using just one 250-gallon (±900 liter) tote carried in the back of a truck. This gives us greater efficiency."

Environmental, Economic Benefits

While treating ROW that cross an Arizona Navajo reservation, Romero calculated impressive environmental benefits. The preblended, returnable/refillable system:

- Saved more than 4 million gallons (14.5 million liters) of water
- Reduced landfill additions by more than 10,000 2.5-gallon (9-liter) jugs, 1,500 pounds (680 kilograms) of cardboard and 550 pallets
- Reduced carbon footprint with less water and herbicide delivery

Beyond the environmental benefits, the herbicide program makes good sense economically, Romero said. "While mowers provide a valuable service, they're extremely expensive," he notes. "The contract for mowing rights of way over five years is $54 million. When compared to the $5 million cost for our herbicide program over five years, the savings quickly add up."

Outstanding Results

The blend used in the Arizona program includes a base of DuPont™ Method® 240 SL and Escort® XP herbicides, Thinvert (an invert emulsion spray fluid), and other herbicides included as needed to control additional brush species.

"The goal of the program is rangeland creation," Romero explains. "For example, by first mowing a heavy stand of brush oak, mesquite or juniper and following up the next year with a selective herbicide treatment on regrowth, we allow native grasses to be released.

"Rights of way we treated three years ago look amazing. All sorts of wildlife are grazing in those areas, and cows are feeding on the new grasslands. The Navajo Nation is grazing sheep on land it couldn't use before.

"I'm very proud of the work we're doing here," Romero adds.

Greater Line Reliability

Jason Myers, national accounts manager for CWC Chemical, Inc., has noticed an increase in turbulent weather across the country in recent years. However, he believes the biggest change in vegetation management for utility companies has been driven by the increased FERC/NERC standards.

CWC Chemical, a herbicide distributor that focuses primarily on utility vegetation management, is headquartered in Cloverdale, Virginia. The company works with major utilities across the country. In the West, Myers assists utility companies that are part of PacifiCorp.

"Increased vegetation management standards have been a very positive thing for our industry," Myers notes. "Utility companies now know what rights-of-way vegetation requirements are, and they have increased funding to get the job done. With greater clearances required along transmissions lines, utilities are reclaiming encroached areas along rights of way and trimming very aggressively to meet FERC standards."

In Arizona, an integrated vegetation management plan by Southwest Ground Control has converted brushy rights of way to native grasses where livestock can graze.

Jason Myers says FERC/NERC standards provide clear vegetation management goals that help transmission lines withstand stronger storms.

From Manitoba to Miami – Advanced Sensors Provide Compelling Information for Effective Grid Operation

While energy efficiency and cost are important to consumers, at the end of the day, electric utilities know that reliability metrics such as CAIDI, SAIFI, and SAIDI reign supreme with both regulators and management. That being said, severe weather and our aging distribution grid continue to pose serious challenges to reducing outages and other service disruptions.

Often times, the construction of new substations, the wholesale replacement of line equipment or the re-conductoring of circuits is simply beyond the limits of the industry's capital resources.

Addressing Changing Demand

Although population growth and renewables integration are changing peak load curves, we often don't know which lines are reaching a critical state until an event occurs. Without this intelligence we are forced to take a remedial rather than a preventative approach to service disruptions caused by line faults. While today's Distribution Management Systems are designed to improve how fast we can find 'em, fix 'em, and forget 'em, they offer little help on how we can prevent faults in the first place. True reliability requires predictive analysis and actionable intelligence so we can respond to events before, rather than after, they happen. How do we get this intelligence? A growing number of utilities are discovering that the newest generation of distribution line sensors holds the answer.

Quicker Field Response, Fewer Service Disruptions

The latest generation of distribution line monitors feature advanced fault detection and sophisticated waveform analytics. They can be quickly deployed and activated anywhere along the distribution grid, and are inductively powered even on low-current lines – no more solar panels or batteries to maintain, and no more RTUs or other pole-mounted equipment to add cost. Advanced distribution line monitors allow utilities to collect real-time operational data, accurately analyze line anomalies in the field, and detect pre-fault conditions before an outage occurs. Distribution line monitors help keep an eye on grid performance anywhere and anytime. With crucial information at their fingertips, dispatchers and operations can take decisive actions that result in quicker field response, fewer disruptions in service, reduced liability from outages, and better capital-investment decisions on infrastructure upgrades.

Industry-Leading Performance on both RF Mesh and Cellular Networks

Headquartered just outside of San Francisco in Burlingame, CA, Sentient Energy is a leading provider of advanced distribution line monitoring and faulted circuit indicators (FCIs) that run on both RF mesh and cellular communications networks. Leading IOUs, like Florida Power & Light, have deployed thousands of

In the substation or in the field, Sentient Energy MM3 Sensors can be placed anywhere on the distribution grid

Sentient sensors along tens of thousands of miles of distribution lines. Together with partner Silver Spring Networks, Sentient delivered the world's first massive scale, advanced line monitoring system for fault detection, interval load logging, and analytics supported on RF mesh communications. Sentient Energy MM3™ sensors are also integrated with Landis+Gyr's Gridstream® RF mesh and CDMA and GSM cellular communications. Deployed in Manitoba, Canada, MM3 sensors have performed during some of the harshest winters in recent memory, providing emergency troubleshooting, substation monitoring and power quality analytics for greater network reliability.

Installed and Activated in Minutes – Maintenance Free

The MM3™ is designed for a long, maintenance-free life. Sentient's IBOLT™ power harvesting technology generates all the power the MM3™ needs from the magnetic field surrounding a conductor carrying as little a 5A. Live-line, hot stick installation takes less than two minutes.

Learn More!

Find out how Sentient Energy's advanced line monitoring technology can improve the intelligence, efficiency, and reliability of your distribution grid. **For more information or to join one of our informative webinars, email info@sentient-energy.com, call (650) 523-6680, or visit our website at www.sentient-energy.com.**

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The Most Dangerous Fault is The One You Don't Know About

Sentient MM3™ Today's Most Advanced and Field Proven Line Monitor/FCI

Remove Risks, Find Faults Faster!

When you have a dangerous line fault, you need to know about it before it becomes a major liability. Sentient MM3 continuously monitors all grid events and captures their high-resolution waveforms. With the MM3, you instantly detect, pinpoint, analyze, and classify any line problem so you can take appropriate action quickly and responsibly. The MM3 is self-powered and requires no RTU or any pole mounted equipment. Hot stick installations take about 90 seconds. **For more information, email info@sentient-energy.com, call (650) 523-6680, or visit our website at www.sentient-energy.com.**

Video: See MM3 Installed in 90 Seconds

Sentient ENERGY

Premix Delivers Multiple Benefits

To help his utility customers get the best control along rights of way, Myers recommends a premix custom blend to handle targeted species. Depending on landholder requirements, his blend often includes Method® 240SL and Escort® XP herbicides. Krenite S brush control agent, Garlon or Rodeo herbicides may also be part of the mixture to control additional brush species.

"The types of treatment used depend on the size of brush being treated, whether it's a transmission or distribution line, and right of way location," Myers says. "We do reclamation treatments in rural areas, where we transition from brush to native grasses that won't interfere with the line.

"In urban areas, where we're working near people's backyards, we need to carefully explain what we're doing to help landowners understand the benefits. A big part of my job is helping applicators communicate with landowners as effectively as possible."

Program Benefits

For utilities, Myers sees many of the same benefits from using preblended, returnable/refillable containers that Romero noted.

"With no measuring or mixing, applicators handle less product for consistent, accurate herbicide blends," he says. "And by using 15-gallon (55-liter) refillable drums, thousands of 2.5-gallon (9-liter) jugs and their packaging materials are kept out of landfills.

"Our utility customers also appreciate the increased accountability about the products they're using. For example, if a utility has hired an applicator to treat 15,000 acres, we can run a report that tracks exactly how much product was delivered for an accurate average volume per acre," he explains. "This type of program creates an important checks-and-balances system for right of way managers."

"With the current program, we now have improved access on more core transmission lines than in the past," Myers adds. "With vegetation under control, lines are better able to withstand storms and turbulent weather for greater reliability."

Hearing Highlights the Need for Proactive Vegetation Management on Federal Land

With the threat of electricity blackouts and catastrophic fires looming, congressional leaders recently convened an oversight hearing to address federal policies that are hampering efforts to keep the lights on. During a May 2014 meeting conducted by the House Committee on Natural Resources Industry, officials called for improved vegetation management and better communication with the electric utilities crossing federal land.

The need for proactive, consistent vegetative management policies on public lands was reiterated throughout the testimony. Utility representatives called for policy changes that would encourage federal land managers to work collaboratively with power companies to achieve those goals.

For more information on the hearing, see the press release "Federal Red-Tape and Inconsistent Decision Making Hampering Efforts to Keep the Lights On and Reduce Forest Fire Risk" at naturalresources.house.gov/news.

About the author

Dan Zapotok is the industrial vegetation management portfolio manager for DuPont Crop Protection, where he is responsible for products within the IVM, railroad and forestry markets. Zapotok has worked with DuPont for more than 20 years, holding positions in operations, project management and marketing. He earned a bachelor's degree from Pennsylvania State University.

Reference

[1]Economic Benefits of Increasing Electric Grid Resilience to Weather Outages, August 2013.

Manitoba Hydro puts Advanced Line Sensor Technology to a real-world test during January blizzard

By Graham Eason

Manitoba Hydro first started testing line sensors in 2006. We suspected that a number of stations on our distribution system were reaching capacity and might need upgrades, but we didn't have consistent, quality data to support our planning decisions. The first sensors we used provided some useful data, but deployment and data collection from these devices was not easy. With the early sensors, we had to manually take them off the line and bring them back to the office to download the data. The next generation offered drive-by data collection which was better, but still a long process. These devices had their limitations. As the technology advanced, remote communication became available. But this required additional externally powered pole-mounted communications equipment that made deployment more expensive and less flexible. These line sensors were solar powered, which proved unreliable in northern locations like Manitoba, Canada.

In 2013, we decided get serious about understanding the potential of distribution line sensors. Manitoba Hydro needs to make informed decisions on capital investment for distribution station upgrades. We needed more consistent, quality, peak load data so we could accurately gage the risks associated with each station. We put out a general RFI to the industry and selected two vendors to pilot 318 sensors in both the urban and rural settings. Both vendor technologies offered three critical capabilities for rapid deployment: line power harvesting to avoid issues with dependable device powering; cellular communications to eliminate the need for additional communications infrastructure, and remote data hosting / support to obtain useable data without making an immediate investment in IT infrastructure.

By December of 2013 we had about 320 sensors deployed. Hotstick deployment, remote back office support, and line power harvesting made these devices easy to install and activate. We immediately began to see that the new sensors could offer a significant operational benefit in addition to load data for our planners. Prior to any switching operation, we now have load data to help ensure we are not overloading equipment. Essentially we can build an historical load curve database in near real time. Had we had this historical data in the past, we could have avoided previous outages due to phase imbalances and overloads.

There's no better test than a real-life crisis

By January 2014 we were in the midst of one of our coldest and roughest winters in 40 years. On January 25, the temperature in Manitoba dropped to minus 30 degrees Celsius, and shortly after midnight, a rupture and subsequent fire occurred on TransCanada Corporation's natural gas pipeline between Otterburne, Manitoba and Hwy 59 – about 80 km south of Winnipeg.

The affected TransCanada pipeline was one of two that supply the Manitoba Hydro natural gas distribution system in an area serving more than 4,000 natural gas customers. Although only one pipeline was severely damaged, the National Energy Board (NEB) and Transportation Safety Board (TSB) requested that TransCanada shut off the gas supply to the second pipeline as a safety precaution. Within about 12 hours, the gas line pressure would be near zero, and 4,000 customers would be left without natural gas heat for their homes, businesses, hospitals and nursing facilities. The arctic temperatures and near blizzard conditions would only make the bad situation worse.

In response, Manitoba Hydro activated its Emergency Operating Centre (EOC) to manage the gas event and monitor the electrical distribution load. What happens when 4,000 customers wake up to no heat and turn to electric space heaters or ovens to get relief from the bitter cold? If the extra load surpassed the capacity of the distribution system serving the area, it could cause outages which would greatly worsen the situation. We knew that some of the distribution lines could reach the critical point. Outages were not an option. We had to get load data from those lines as soon as possible to develop contingency plans.

We still had a dozen of the new sensors sitting in our office waiting to be deployed under better weather conditions. I and other crew members from Manitoba Hydro's Distribution Engineering Services Department loaded them into a few trucks and headed for the critical substations in the affected areas. Before we left, we pieced together and alerted several line crews to meet us there, letting them know we were bringing the sensors. We also contacted our two vendors and told them we needed these sensors assigned and setup to send us load data every five minutes. And we needed this to happen as soon as the sensors where hung.

Nobody likes to do line work in high wind chills and minus 30°C temperatures. Fortunately the sensors install quickly. All we needed to do was hang them up and text the serial numbers to the appropriate vendors who were located as far away as San Francisco. A half-hour later, we had access to the load data in 5-minute intervals. By 5 PM all 12 sensors were remotely provisioned, live, and feeding data to Manitoba Hydro through the vendor web portals.

TransCanada Corporation was extremely professional in their response to the rupture, and service was fully restored within a few days. During that time, distribution line load reached near-capacity limits. Thankfully, the sensors allowed us to provide immediate situational awareness to our Emergency Operating Center, while monitoring and managing the event without experiencing outages or subjecting our customers to unnecessary disruptions in electric service.

Future deployment – the dilemma of the chicken and the egg

During our pilot program, we will continue to put sensors at stations which we believe could be nearing maximum load. Many of these stations are located in pockets experiencing high growth and development. This is going to be our challenge moving forward in a time where capital expenditures are under close scrutiny. Which locations do we spend our money on today, and which ones do we think we can defer to the future? The deployment of more sensors at additional locations would certainly help us make these decisions. Ironically, the capital required to purchase sensors competes with the capital to deploy the IT infrastructure that will optimize the value of the data they provide. It's the classic 'chicken and egg' dilemma.

There is no question that this new generation of advanced distribution line monitor/sensors can add significant value for both our Operations and Distribution Engineering teams. The historical data on peak load has already helped us make better operational and investment decisions. And we've only scratched the surface on the value of the 'Communicating Faulted Circuit Indicator' (cFCI) technology some of these sensors provide. But the real value will come when we can transform this data into actionable intelligence that can get to our field crews in near real time. That's only going to happen with investment in the proper IT infrastructure such as an OMS or DMS. We are at the point where we have hired Siemens to create an implementation roadmap to identify and understand the value and best timing of these investments to maximize ROI.

Debating network communications and data hosting

Another consideration we wrestle with for future sensor rollout is data communications infrastructure. All the sensors in our pilot program communicate via cellular modems, but cellular charges adds to our annual O&M expenditures, which is always under scrutiny. The advantage we saw for cellular was quick deployment, minimal capital investment, and end-to-end support from the vendors. Developing our own communications infrastructure to service AMI or developing the utilities 1.8 GHz wi–max system is still some time away, so our options were limited. In addition, dependable cellular coverage is only available in about 30 percent of our service territory. To address the cellular shortcomings, we are currently working with the California based vendor to test range extender units that would allow us to expand sensor deployments to areas with spotty cellular service.

Data hosting enabled us to implement this technology without immediate investment in IT infrastructure and operational support. It also allowed us to understand the complexity of the technology with full support from the vendors. Whether we bring this technology in-house or continue to have it hosted, will for now, depend on operational costs and internal resources available to support it. The pilot has definitely challenged some of our assumptions in terms of understanding this type of technology and highlighted a number of processes which need to be addressed before a larger scale implementation can occur.

We will look to our implementation roadmap to help us decide when and where we expand deployment of these sensors. But based on the initial pilots, there is little question that if the data they provide is fully utilized, the result will be better operational efficiency for Manitoba Hydro and better reliability for our customers.

About the author

Graham Eason is a Certified Engineering Technologist (C.E.T.) for Distribution Performance Engineering at Manitoba Hydro. He has been employed for more than 25 years starting his career at Manitoba Hydro as a protection technician on the transmission system, and then moved to distribution in 2002. He is currently charged with reliability improvement initiatives and piloting new technologies on the utility's distribution system. Graham has been involved in the Distribution Roadmap initiative since 2006, and continues to be involved with the current Siemens Compass initiative Manitoba Hydro is undertaking.

Transformer Down! Dealing with Emergency Replacement of Transformers to Keep Production On-Line

Knowing about transformer construction provides the first line of defense. Rapid access to plug-and-play replacements can save hundreds of thousands of dollars per day.

By David Rizzo

How much can you afford to lose? For any CEO or manager in charge of a plant that purchases electricity in bulk, that question must be faced when considering the replacement of a power transformer. If one goes down, the loss of operational capability is always crippling. The process gets interrupted, the assembly line halts, and information transfer stops in its tracks.

Transformers seldom go down, but when they do the effects to the bottom line are immediate and devastating. Beyond the lost income from the sudden stoppage of the production run, the risk of subsequent fires, fines, security lapses and lawsuits can quadruple the damages. The effects ripple throughout the organization. Managers get fired and, if the outage lasts long enough, stockholders get angry.

Utilizing a two-pronged approach, though, facility managers can stack the odds in their favor and prevent the loss of hundreds-of-thousands of dollars. Prevention prevails through the selection of quality transformers in the first place. Secondly, quick replacement with an exact match can keep losses to a minimum.

Identifying a robust transformer

A basic knowledge of the design, construction and materials of power transformers provides facility managers – as well as those who sign the purchase order for such big-ticket items – with the ability to maximize the return on investment on what is arguably the heart of any industrial plant. More importantly, it can help prevent disastrous emergencies from taking place at all.

Starting from the top, power transformers are required to step-down the higher voltages delivered by the electric utility company. Common types of transformers found in industrial plants include liquid-filled (so called because they use oil, or similar, for cooling purposes), and dry type transformers. Given that dry types are air-cooled, they pose less chance of leakage and fire risk.

"Whether oil-filled or dry, the design, construction and materials used make a huge difference in terms of transformer reliability," says Alan Ober, vice president of Engineering and Manufacturing for Electric Service Company. Founded in 1912 by former Westinghouse engineers, the firm specializes in providing quality new, repaired, and rebuilt transformers – under emergency conditions when necessary – from their manufacturing plant.

Dry type transformer for emergency replacement - designed to duplicate 'form, fit and function' as closely as possible

According to Ober, the way the coils are wound around the core of the transformer greatly affects its robustness. Because of increased axial forces acting at the corners of rectangular wound transformers, energy gets wasted and noise is created. On the other hand, voltage stresses are halved between the discs of comb-wound designs. Hence, round-wound transformers stay cooler, run quieter, and present less risk of short circuit.

Beyond the improved reliability factor, the increased efficiency of the round design saves costs in real time, as the plant consumes less electricity. Some wound round transformers even exceed the proposed efficiency standards for Energy Star compliance, drastically lowering utility costs for a plant, according to Ober.

Transformer Down! Dealing with Emergency Replacement of Transformers to Keep Production On-Line

What to do when the power goes out

Any plant or facility that's been in operation for a while is subject to a sudden loss of power since many transformer failures stem from the fact that so many older models are still in place.

"The transformers that failed at our plant were 37 years old – definitely at their end-of-life cycle," recalls Jonathon Peper, senior engineer at PacifiCorp's Wyodak Plant in Gillette, WY. PacifiCorp delivers electricity to more than 724,000 homes and businesses in the Northwest through 74 generating plants, 61,500 miles of electric distribution line, and 15,800 miles of transmission line. "Faults, like voltage transients, that they were able to handle when new, are just the final last hurrah. Shorts occur because over the years heat and moisture degrade the insulation, especially paper."

Peper describes how in July of 2013 they lost a 1.5 MVA transformer that fed a critical piece of equipment. As a result of the fault, the entire plant went down.

"When that happens, we have to purchase electricity from elsewhere at spot market prices," Peper explains. "That downtime can cost us anywhere from $300,000 to $700,000 per day depending on variations in load peaks, day of the week, and weather."

To rapidly stem such losses, transformer companies exist that specialize in emergency replacement. For mission critical applications, transformers can be prepped for shipping within a matter of hours. But to ensure a rapid return to operation, any replacement transformer must duplicate 'form, fit and function' as much as possible.

"The biggest challenge we face is fitting the transformer in the enclosure and getting the existing switch gear to line-up," says Tom Arnold, a project manager with one of the nation's leading electrical contractors. "You can't change the cabinet because there's other gear on each side of it, so a full day can be wasted while we have to rework all the bussings."

Attention to details like duplication of the high and low voltage bussbars can spell the difference between a lengthy and costly replacement process versus a quick, cost-effective plug-and-play solution.

Transformer assembly requires highest level of duplication

"The guys at ELSCO come out and do field measurements, and then they go back to the shop and build it so that we can avoid such issues," Arnold continues. "We've put in 13-14 of their transformers and they line right up so it makes the job go a lot quicker. For instance, we did one rush job for a national airfreight company that suddenly lost its transformer. They ordered a rental unit from ELSCO and they got it here in a couple of hours. We then put it in and got them going again so they could still run freight that very same day."

Similar replacement success took place at the Pacific Power plant.

"We got hold of ELSCO and they came back with a design that met the exact specification I was after," says Peper. "They delivered a transformer that fit in the existing location without us needing to modify the enclosure or move the switchgear and the high side disconnect switch. We ended up buying a total of five dry type transformers from them. In every case we got a great design."

Saving more money by remanufacturing

In cases where no exact replacement units are immediately available, many companies offer similar units for rent while the original plant transformer is remanufactured. This keeps plants fully operational until the original transformer – in like-new condition – can be placed back on the pad.

Similar considerations apply when purchasing a reconditioned transformer as for a new one; except that the expertise of the remanufacturer plays a greater role.

"At the bottom end of the remanufacturing scale are transformers that are brought in, fixed up just enough to be operational, superficially cleaned and then sent out the door," notes Ober. "These won't hold up as well as transformers that are completely refurbished, and could leave your plant vulnerable once again."

A more completely remanufactured transformer provides far greater security against failures. There should be a complete rewinding of the primary and secondary coils along with brand new high and low voltage bussbars. While the original core can be kept 90 percent of the time, even it must be replaced occasionally as older steel is less energy efficient than modern core materials.

Attention to detail pays dividends in the remanufacturing process. Hand winding ensures the highest quality. Additionally, the deburring of the copper conductor helps ensure that the insulation won't be punctured and create a short circuit.

Ultimately, any remanufactured transformer must meet or exceed all NEMA, ANSI and IEEE standards.

About the author

David Rizzo is a Torrance, California-based author. He has penned three trade books, 200 technical articles and 500 newspaper columns. Rizzo covers a wide range of topics, specializing in technology, medicine and transportation.