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The Perfect Storm in Transformer Maintenance

Electric Energy T&D MAGAZINE

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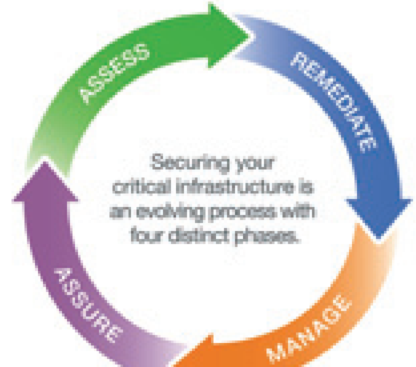

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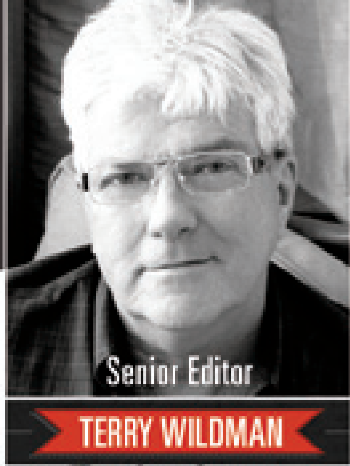


POWERPOINTS

The Power of Words

I am now on my second issue of EET&D. I want to reach out to all of our readers with my take on the value of a publication like ours. You may think as you read this that I'm rambling with no point or end in sight, but I assure you that I really do have something important to say.

A while ago I had a conversation with a good friend of mine, the CFO of a huge, well-known Japanese electronics firm about the impact a company's promotional activities can have on its success. Working at the company's Canadian headquarters my friend was definitely used to the trials and tribulations of market fluctuations. He had recently brought the company through one of the worst recessions in current memory – and in much better fiscal shape than its competitors. One would naturally think that this is the role of any financial department head – and that would normally be true. But when companies all around you are dropping like flies and their customers disappearing in exponential numbers, having a formula for success is absolutely essential. It was his expertise and knowledge that allowed the company to emerge in such sound condition.

"So, tell me your secret," I said.

The answer he gave has stuck with me to this day. He told me that during slow times, most companies cut back on two main departments – marketing and advertising. The rationale is always the same; positive contributions notwithstanding, these entities do not generate hard cash per se but in fact need generous budgets to stay alive within the firm's framework and they get cut. "Dismantling these units is in my estimation and experience one of the worst things a company should do," he said. "What it is doing is taking all of the value in market exposure gained through advertising and promotion in the good times and throwing that away, essentially driving the company to the bottom of the ladder in its area of expertise.

"Often they don't understand just how damaging these types of cuts can be to their operations," he continued. "Their challenges really begin when prosperous times return and they're left staring up the trouser legs of their competitors – the ones that had the foresight to keep their most valuable advertising and media connections in place," he continued. "Those firms now have serious momentum, which gives them the proverbial leg up. Make no mistake. It's not easy but those marketing and advertising managers formed and maintained the strongest relationships with the media outlets knowing that they bring true value and lasting quality in good times and in bad."

The power of the media, particularly the print media, is formidable.

"Media can and, in fact, has been the difference between success and failure for many companies large and small. Support is a two-way street and that aspect is never more important than when times are economically tough." The conviction with which he spoke was impressive. "So you realize that those firms left looking up are faced with having to start all over again, rebuilding contacts and relationships with the media, relationships their competition has maintained. Gaining ground could take months – time handed to the competition on a silver platter.

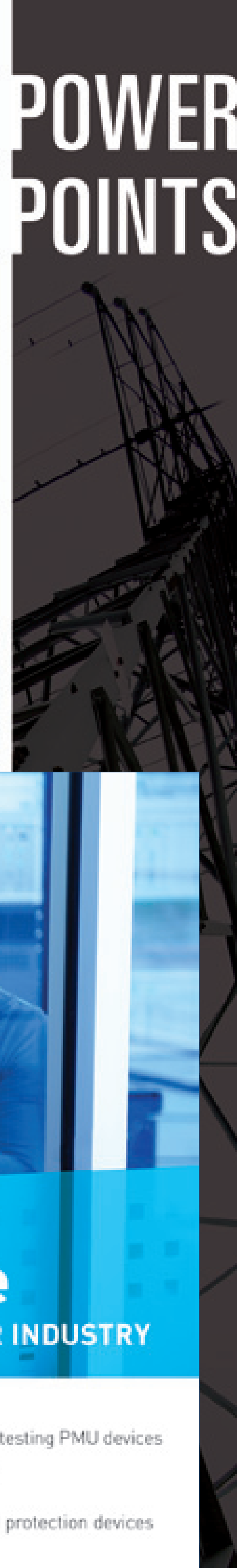
It's also unlikely that the people let go will be available or even willing, to return. Once the working bond is broken, it's very tough to regain. I know from experience that the out-of-work people are often hired by the firms that have come out of the gate that much stronger."

As marketing manager for a large international company some years ago, part of my job was to get the company into the press. I always felt, however, that editors tried to lord it over us common-folk and to get their attention was tough, to get their acknowledgement was like finding gold, and to actually get ink was a miracle. I have never understood that attitude and pride myself in not being that type of editor. I believe, as writers Lewis Coser, Charles Kadushin, and Walter Powell wrote in *'Books: The Culture and Commerce of Publishing'* that, "The publishing industry functions as gatekeepers of ideas insofar as they make decisions about what to 'let in' and what to 'keep out.'" We are often that bastion of reason and experience that keeps us all looking and sounding good.

I love the electric transmission and distribution industry and I am privileged to be the editor-in-chief of Electric Energy T&D magazine. One of my goals is to attract the cream of the crop in the world of electricity transmission and distribution. To this end I can provide an unbeatable opportunity for editorial contributors to get their word out; energy providers to get their news out; and advertisers to get their message out, all in a timely fashion in the highest quality publication. You can be confident your words will reach the most qualified and influential people in the electric energy industry. I really believe there is true value in 'seeing is believing.'

I invite you to become part of our media family and take advantage of the position and influence EET&D already enjoys in your marketplace. I know we will make each other better and that our success is closely tied to yours. As always we will work with you and I am confident the time and energy you invest in us will reap very positive returns – on all fronts. You can also be assured that your interests will be respected and protected as we do not operate on a 'pay-to-play' basis whereby advertising revenue entitles editorial insertion. We provide a clear and level playing field.

Again, to all of our readers, prospective readers, vendors, and utilities, Electric Energy T&D magazine is truly open for your business. Together, we can make it all happen. **Ed**.



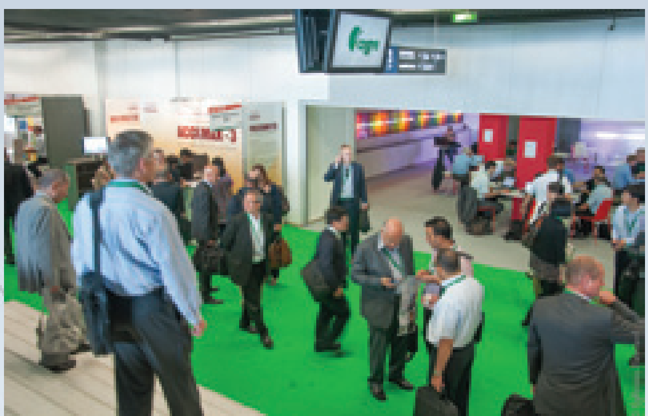
2012 Paris Session, 26 to 31 August 2012

By FM

Dear Colleagues, dear friends, Ladies and Gentlemen,

Allow me first of all to thank you for all the positive feedback I received for this Session.

2012 is the edition where records were broken: 3200 participants attended the session (3000 in 2010), 3626 visitors attended the exhibition (2385 in 2010). The exhibition, now on two levels, allowed an increase of 50% of the available surface, allowing for 198 exhibitors (i.e. +44%), and a more open, more comfortable general layout.



For the Opening Ceremony; we had the chance to hear Mr Liu Zenhya, the President of the State Power Grid of China. He presented us with a new intercontinental vision of the trade of electricity, suggesting exchanges from China to Europe through EHV DC links. No doubt this will concern a large amount of CIGRE activity in the future. This figure gives one of the scenarios presented.

The Opening Ceremony was also the opportunity to present the winners of the CIGRE awards:

- The CIGRE medal was granted to both André Merlin, for his exceptional contribution to CIGRE during 40 years, and to Colin Ray for his great involvement in our activity for SC 37/C1, for the TC 10 year Strategic Plan, and for the UK NC.

- Honorary Membership was given to these well known members of our association:
  Javier AMANTEGUI (Spain)
  Franz BESOLD (Germany)
  Chris JONES (United Kingdom)
  José Henrique MACHADO FERNANDES (Brazil)
  Antonio NEGRI (Italy)
  Liliane NEY (France)
  Carlo Alberto NUCCI (Italy)
  Mark WALDRON (United Kingdom)

The Opening Panel dealt with a very topical subject: "The role of Electricity Systems in Reducing Energy's Environmental Impact". Led by Klaus Froehlich, it was a very comprehensive survey of the question, and the role CIGRE plays there. The afternoon Panel on large disturbances, provided us with a good overview of these events in the world during the last two years, including an intervention by our Indian colleagues concerning the two large blackouts they experienced at the end of July.

The governing bodies met during the Session, resulting in the elections of the three new officers for our Association:

- President: Klaus Froehlich (Switzerland),
- Treasurer: Richard Bevan (Australia),
- Chairman of the Technical Committee: Mark Waldron (United Kingdom).

The Steering Committee members were also appointed. Apart from the Officers, they are: VAREJAO de GODOY Antonio(Brazil), DJYAKOV Anatoly F. (Russia), GELLINGS Clark W. (United States), CHRISTENSEN Jorgen (Denmark), LI Ruomei, Dr. (Mrs) (China), AUGONNET Michel (France), WINSER Nick (United Kingdom), NIEHAGE Udo, Dr.-Ing. (Germany), NIZOVOY Jorge Alberto (Argentina), RASHWAN Mohamed, Dr. (Canada), STEPHEN Robert George (South Africa), TAI Ichiro, Dr. (Japan), YOUNES Hassan Ahmed, H.E Dr. (Egypt).

The two members of the Administrative Council that became members of the Technical Committee are KLING Will (Netherlands) and VELASCO Luis (Peru, Chairman of the Andean Committee).

The discussion meetings took place between the 28th and 31st of August. This year, all SCs held Poster Sessions, and they have been very successful. Let us also note that the increase of number of technical meetings during the Session was around 50%, as compared to 2010.

Another modification we introduced this year was to hold the official reception under the "Pyramide du Louvre" which was a good success.

Virginia Gov. Bob McDonnell Dedicates Dominion Virginia Power's Virginia City Hybrid Energy Center

St. Paul, VA, September, 2012 - Virginia Gov. Bob McDonnell joined Dominion Virginia Power officials in dedicating the new Virginia City Hybrid Energy Center, marking the completion of a four-year, $1.8-billion construction project that is bringing an economic boost to Southwest Virginia.

The power station, one of the cleanest of its kind, will help Dominion Virginia Power meet an anticipated 4,000-megawatt growth in electricity demand from its customers during the next decade. The facility uses coal and renewable biomass to generate enough electricity to power 146,000 homes.

The station brings significant economic and environmental benefits. It will account for $258 million annually for the economy of Southwest Virginia, including $6 million in annual tax payments to Wise County. Virginia's air will be cleaner because the company is converting the older coal-burning Bremo Power Station to natural gas as part of the Virginia City air permit.

"This amazing project is part of a $4 billion planned investment by Dominion to provide for the energy needs of a growing Virginia economy, an investment that will include completion of six power station projects over the next two years," McDonnell said. "The station's state-of-the art environmental controls prove that coal can be burned cleanly and will remain an important part of the commonwealth's energy picture for decades to come."

Thomas F. Farrell II, Dominion chairman, president and chief executive officer, said: "Virginia City is a welcome addition to our generating fleet and helps ensure reliable power, a diverse energy mix and stable, economic rates for our customers. We are committed to being a good neighbor in Southwest Virginia because that is an integral part of who we are as a company."

Gov. McDonnell and Farrell were joined at the ceremony by many officials and civic leaders from Southwest Virginia, including state Sen. Phillip Puckett, D-Tazewell, Delegate Terry Kilgore, R-Scott and former state Sen. William Wampler, R-Bristol.

"The Virginia City Hybrid Energy Center has been a great long-term benefit for our entire region, especially during this Great Recession," said Puckett.

"As a major supporter of this project since 2004, I am delighted that this clean coal power station has completed its final milestone – the dedication," said Kilgore.

Virginia City entered commercial service in July. The station uses advanced circulating fluidized-bed technology and burns run-of-mine coal, waste coal and up-to-20 percent renewable biomass in two boilers to produce 585 megawatts of electricity. Emissions of sulfur dioxide, nitrogen oxides, particulate matter and mercury are held to levels that are roughly 99 percent below levels of similar units built in the 1960s.

Farrell singled out Eva T. Hardy, a retired Dominion executive vice president, for being a champion of the Wise County project. "Eva worked tirelessly with state and local officials, regulators and community groups to pave the way for the acceptance and support of this power station."

At the ceremony the Dominion Foundation presented gifts of $25,000 each to Feeding America – Southwest Virginia, a regional food bank; Mountain Empire Older Citizens for the agency's fuel fund for the elderly; and The Health Wagon, a free clinic and administrator of an annual three-day health fair, RAM, that provides free medical and dental care to roughly 2,000 people.

THE GRID TRANSFORMATION FORUM

Envisioning the 21st Century Grid

Improving Operational Efficiency and Customer Service with Big Data/Analytics

EET&D speaks with **Rodger Smith,** senior vice president and general manager, Oracle Utilities

EET&D: Rodger, I think we can probably agree that we begin our discussion today at a very pivotal point in the evolution of the utilities industry. Many utilities have rolled out, or are rolling out, widespread technology initiatives that generate—via smart meters and other systems—a wealth of data. Do you think utilities are actually prepared to manage and make use of the massive data volumes they are collecting?

Smith: Today, as a result of smart meters and other systems, utilities are forced to deal with unprecedented amounts of interval, voltage, and interruption information. Simultaneously, a new generation of grid nodes and sensors detects and reports every system anomaly while adding to utilities' already overburdened asset inventory. Meanwhile, production systems churn out reams of new financial, customer, and staffing information. Utilities have not previously had access to much of this information.

I think the main questions we need to ask include, "How will access to this new data change the way utilities drive their businesses?" and "Will predictive analytics spur operational change?"

In fact, along those lines, Oracle recently surveyed more than 150 executives at North American utilities with smart meter programs in place to gauge their perceptions on the business impact of "big data," their preparedness to handle this huge data growth, and their plans to extract optimal business value from this data to better target, engage with, and serve their customers.

We found that the average utility with at least one smart meter program in place has increased the frequency of its data collection by 180x—collecting data once every four hours as opposed to just once a month. While that might not be very surprising, it's still a big number. The good news is that utilities with smart meter programs in place say they are somewhat prepared to manage the data deluge, rating themselves a 6.7 on a scale of 1 to 10. Utilities also said that they are collecting critical information, such as outage (78%) and voltage data (73%), and many are using it to support business operations, improve service reliability, and enhance customer satisfaction.

However, there is still significant opportunity on the horizon.

EET&D: Could you expand on your last point a bit?

Smith: Utilities can use the massive data volumes they collect from smart meters and other systems to place a renewed focus on network and service reliability.

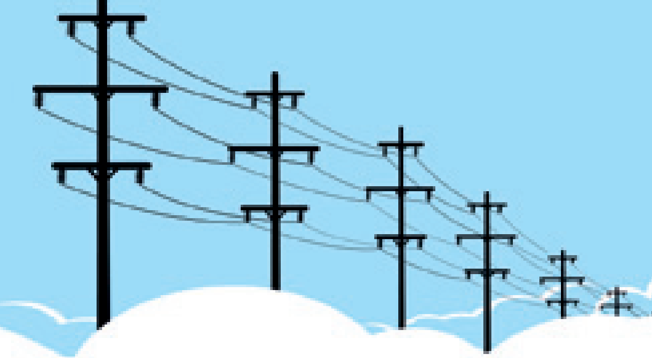
Unprecedented data availability—coupled with sophisticated analytics solutions—will drive utilities to evolve many aspects of their businesses. For example, asset risk analysis will help utilities to identify and avoid operational risks, such as major/catastrophic events. Utilities can integrate work and asset management systems with field operational performance data to better assess risk.

Another change-enabler I see is utilities' growing use of distributed intelligence for distributed generation management and distribution automation. Utilities can further improve reliability through automated self-restoring and system optimization controls to ultimately improve customer satisfaction.

I believe we will also see an increased use of mobile workforce management and asset management systems to support knowledge transfer between aging field workforce and "digital native" new hires. Mobile workforce management systems will pay for themselves based on crew efficiency, but utilities will derive the real value from field information management and data quality gains.

I could go on and on and on, but I think I covered some of the more important points here.

EET&D: So, it's not just about smart meters, is it?



Smith: Smart meters are certainly bringing in a constant stream of outage, interval, and voltage information—but they're not the only sources contributing to utilities' data overflow. Other sources include outage/distribution management, customer data/feedback, alternative energy sources, as well as advanced sensors, controls, and grid-healing elements.

The majority of our survey respondents said that drawing intelligence from smart grid/smart meter data is among their top three priorities, however, the average utility is just somewhat prepared to handle the data deluge—noting deficiencies in analytics. Our study found that today, even though utilities have access to unprecedented volume and variety of data from smart grid roll-outs, 45% of them struggle to report information to business managers as fast as they need it and 50% miss opportunities to deliver useful information to their customers. The study also found that utilities see a need to improve their ability to translate information into actionable intelligence and leverage data for strategic decision-making. We also asked respondents if they had a meter data management (MDM) system in place, and found that 70% of those with an MDM system said they are prepared to successfully manage the data influx versus just 51% of those without.

It's not about just collecting data—utilities must have the right systems, people, and processes in place to analyze the data, report on it, and act on it—to improve business operational efficiency, service reliability, and customer engagement. Otherwise, it will be impossible to make sense of the staggering amount of data they're collecting from smart meters and other smart grid components.

EET&D: How can utilities specifically use the data they're collecting and what types of analysis should they perform?

Smith: As utilities gain the ability to analyze big data, they will realize deeper levels of insight into how their own businesses operate and into their customers' needs.

Efficient transmission and distribution (T&D) infrastructure management has always been a top priority for utilities, and it remains a key component of any smart grid strategy. With the influx of new T&D smart grid data, asset management complexity has grown as well.

Today—through work and asset management systems, geographic information systems, supervisory control and data acquisition (SCADA) systems, sensors, grid nodes, mobile devices, and more—utilities have real-time visibility into the conditions and performance of specific assets, opening up a whole new world of possibilities for optimizing asset management. Work and asset management systems integrate to field operational performance data to enable utilities to identify potential issues and better assess risk. Moreover, analytics capabilities provide insights that help utilities determine the best time to repair or replace assets—helping them to reduce maintenance costs and make the right buying decisions.

Further, utilities can use the "big data" they're collecting from their customers—from website communications, social media engagement, etc.—to provide better, more personalized services based on customer needs.

With integrated systems and the sophisticated analytics tools available today, utilities can move toward developing a true 360-degree view of every aspect of their businesses—helping them transform processes and support effective decision-making.

EET&D: What types of tools and skill-sets should utilities evaluate to enable this level of analysis?

Smith: As data management becomes more and more complex, utilities need open, standards-based IT systems that allow for easy integration and data sharing. They need access to business intelligence tools that are tailored to their specific needs. These tools for statistical and advanced analysis must work with distributed data to perform analysis regardless of where the data resides, scale as data volume grows, and automate decisions based on analytical models. Underneath it all, utilities need the foundational database, hardware, and storage for superior reliability, performance, and security. All of these solutions should be modular and flexible – providing utilities with choices, enabling them to implement what they need, when they need it, to address the challenges that are most important to them.

But they also need the right people to do the job. There is a unique skill-set required to examine patterns in unstructured data. Investment in people is very important.

EET&D: Are you seeing any other factors emerge that weren't originally included in utilities' business cases for smart meters?

Smith: Today, we're seeing a growing focus on load forecasting and asset management.

The initial smart grid value proposition was around providing better information to customers to drive smarter energy use, as well as supporting demand response and conservation programs. Those are, of course, still important. But, we are seeing an increased focus on leveraging the data generated by smart grids to improve network performance, distribution management, and asset optimization. These improvements will lead to more satisfied customers while they drive process improvements and cost reductions for utilities. Intelligent load forecasting, for example, enables utilities to identify how much electricity they will need in the future, predict monthly sales revenue and unbilled consumption, and support asset management, load analysis, and predictive maintenance.

If utilities can generate more accurate load profiles, they can better anticipate their forecasted load. If they can dial back their traditional overage calculation by even a couple percent, they can potentially save millions of dollars. In addition, they can look at excess system load and sell that back into the grid—another huge cost savings.

EET&D: To close, what other trends are on the horizon in the short term?

Smith: With data coming in from every corner of the business—from outage/distribution management, alternative energy sources, advanced sensors, controls, grid-healing elements, etc.—utilities have the opportunity to use that data to improve operational performance across every aspect of their businesses—from asset reliability and replacement planning, to load forecasting and distribution management, to customer communications and conservation programs.

As our survey results indicated, utilities must not only make data collection a priority, but invest in the systems and people needed to make sense of a growing number of new data sources collected from smart meters and other smart grid components. In addition to streamlining business operations, successful data management should greatly improve the customer experience—both through improved outage management/service reliability and stronger customer communication around smart grid changes and benefits. I truly look forward to what the future holds for the utilities industry. I'm excited to be a part of it, and think we're on the brink of something really great.

EET&D: We want to thank you Rodger for taking the time out of a busy schedule to share your knowledge, experience, and insights with our readers. We agree with you that the utilities industry is headed for some very exciting times particularly in the realm of data management.

Rodger E. Smith is senior vice president and general manager for the Oracle Tax and Utilities Global Business Unit. In this position, he leads the global business unit's solution groups, strategic planning, product development, sales, service, and support.

Mr. Smith is the former president of Enterprise Management Solutions (EMS), the management consulting division of Black & Veatch. In this position, he grew the division into one of the largest management consulting organizations specializing in energy and water. He previously held positions with PricewaterhouseCoopers and Southern Company, one of the largest electric utilities in the United States.

GREEN OVATIONS

Innovations in Green Technologies

Smart Home Energy Management with or without the Smart Meter

By Louis Szablya, VP of Marketing and Product Management at Energate

A recent report by The Edison Foundation's Institute for Electric Efficiency estimated that about 27 million smart meters had been installed in the U.S. as of September 2011, representing approximately 22 percent of U.S. households. The report also estimates that just over half of all U.S. households (54 percent) will have a smart meter by the end of 2015. Given the growing desire by utilities to reduce peak demand, and by consumers to save money by controlling energy utilization more effectively, is there anything that can be done for today's underserved and unserved majority of residential customers now?

Long before the advent of the smart grid and smart meters, electric utilities used a variety of demand-side management programs to reduce peak demand. These programs initially focused on commercial and industrial customers as the major users of electrical energy. More recently, residential demand-side management programs have been implemented using direct load control (DLC) for air conditioner compressors, pool pumps, and electric water heaters. The network infrastructure requirements for residential DLC are fairly modest, and can often be satisfied by an existing pager or other one-way broadcast network.

While a residential DLC program may be necessary to achieve meaningful reductions in peak demand, they are not sufficient. Demand response (DR) programs are therefore, also needed, but these have more demanding infrastructure requirements. For the relatively small number of relatively large commercial and industrial customers, the investment in the requisite infrastructure is fairly easy to justify. For the relatively large number of relatively small residential customers, however, the fairly high investment in infrastructure and equipment required remains an impediment to some much-needed progress.

This article explores what electric utilities can do to implement smart home energy management programs cost-effectively in the absence of a fully-functional and service area-wide advanced metering infrastructure. Before exploring the two options available, it is useful to characterize the ideal arrangement, or "best case" use case for smart home energy management.

'Best Case' Use Case for Smart Home Energy Management

Demand response has been identified as a 'killer application' for the smart grid, and an effective residential DR program requires a smart yet simple home energy management system (HEMS). Indeed, it is the 'smart' part of the smart thermostat or home energy gateway that is critical to encouraging consumer acceptance and adoption by making the HEMS simple enough for the average person to use. Consumers want savings of course, but they also want convenience and comfort without complexity.

To be truly smart (and therefore 'set-and-forget' simple), the utility must be able to communicate with the home energy management system—and vice versa. This two-way, end-to-end communications capability requires two separate networks. One is the so-called neighborhood area network (NAN) that is part of the advanced metering infrastructure (AMI) needed for reading the interval data from the smart meters. The other is the home area network (HAN) that enables the smart meter, and therefore the utility, to communicate with the HEMS.

Ideally the NAN is sufficiently robust that, in addition to its primary task of reading meter interval data, it can also accommodate residential DR and other smart grid applications, such as distribution and substation automation, outage management, volt/VAR optimization, etc. To handle all of these applications well, the NAN must have an adequate amount of both upstream and downstream bandwidth, and provide acceptable levels or quality of service, especially for protocols requiring near real-time communications.

For its role in residential DR, the NAN would need to be able to send dynamic pricing signals (whether time-of-use, real-time or critical peak) via the smart meter's HAN to the home energy management system. The smart thermostat or home energy gateway in the HEMS would receive and then respond to the changing prices based on (easily set) customer preferences, and communicate the results back to the utility via the HAN and NAN.

In the U.S. the HAN used for DR is likely based on the ZigBee wireless networking protocol, along with its companion Smart Energy Profile (SEP), which specifies the home energy management protocols and applications, including for demand response, receipt of pricing signals, load control commands and text messages from the utility, time synchronization, security, etc. Based on these comprehensive capabilities, SEP version 2.0 has been selected by the U.S. National Institute of Standards and Technology for residential demand response in the Smart Grid Interoperability Standards Framework. Because SEP 2.0, while still supporting ZigBee, is also network-agnostic, it has now earned additional support from the HomePlug Powerline Alliance, HomeGrid Forum, SunSpec Alliance, Wi-Fi Alliance, IPSO Alliance and International Society of Automotive Engineers.

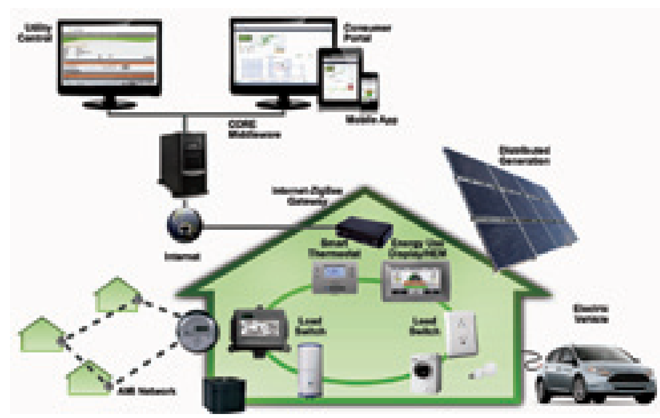
The ‘HAN-less Smart Meter’ Use Case

For some utilities that have deployed an AMI network, the smart meters can lack the end-to-end communications needed for residential DR for two reasons:

1. Either the meters are not equipped with a HAN
2. The AMI network is insufficient to handle the information exchanges required.

It is entirely possible that if the latter is the case, the former is also true as there is really no need to support a HAN in the smart meters. According to Parks Associates, as few as 10 percent of the smart meters currently installed are equipped with two-way communications between the home and the utility. Other analysts predict more or less HAN penetration, but the result is the same – another network is needed to facilitate residential DR.

Fortunately, there already exists a ubiquitous, reliable, secure and always-on two-way data communications network suitable for DR that is available in every utility’s service area: the Internet. Broadband Internet access is now available to virtually every home in the industrialized world, and in the U.S. is already installed in 63 percent of them. The penetration in larger residences with the highest potential return on the DR investment is even greater. And the extent of broadband Internet access will only continue to increase as digital subscriber line (DSL), cable modem, third- or fourth-generation (3G/4G) cellular communications, and satellite services are expanded and competition among these alternatives lowers subscription rates. All that is needed for utilities to take advantage of the Internet is a dedicated gateway to connect the broadband Internet modem to the HAN, as shown in the figure. The gateway provides continuous two-way communications between the utility and the consumer’s home energy management system devices, such as a smart thermostat or an energy use display shown. The gateway establishes a secure “service entrance” into the home by connecting both to the broadband modem (via Ethernet) and to the ZigBee, Wi-Fi or other HAN. The gateway is configured for secure, encrypted communications between the utility’s DR application and the in-premises HEMS, and if the utility chooses, optional direct load control for other loads, enabling them to also receive dynamic pricing and/or direct control signals.



Wireless ZigBee HAN served by both a broadband Internet gateway and an AMI network. Note the ability to control other loads, including the charging of electric vehicles, which will be supported in future versions of the Smart Energy Profile.

It is important to note that this configuration is just as good as the ‘Best Case’ use case. It works with either dynamic pricing or published TOU rates, and because it provides even more capable communications into the home, the configuration affords an opportunity to implement home energy management applications that are even more sophisticated than most AMI networks are capable of supporting. For this reason, some utilities with an AMI network use Internet-HAN gateways for some or all residential DR programs, particularly for those requiring a higher bandwidth or lower latency than the AMI supports.

The ‘Dumb Meter’ Use Case

For homes that still have a ‘dumb’ electromechanical meter or even a ‘semi-smart’ meter incapable of capturing interval data (perhaps as part of an automated meter reading system), the ‘HAN-less’ configuration described above can be just as effective, but with one major difference: There is no way to use dynamic pricing. But this is not necessarily as big an impediment to residential DR as it might first appear to be.

There are many ways to provide incentives for consumers to reduce consumption during periods of peak demand other than higher 'punitive' rates that require interval data. Residential direct-load control programs have long used the one-time rebate as an incentive, but the availability of two-way communications via the Internet-HAN gateway gives utilities substantially more flexibility to craft more compelling incentives.

Some smart thermostats and home energy gateways enable the utility to capture the users' control settings to assess their impact on reducing peak demand. For example, the smart thermostat may be programmed to increase the temperature setting whenever it receives notification of a DR event from the utility or while TOU rates are in effect; the greater the increase in temperature (and therefore the greater the demand reduction), the larger the potential incentive. The home energy gateway might also be configured to temporarily shut off additional major loads, such as a water heater or pool pump. The utility could then provide a range of rebates (for a fixed rate structure) depending on how much each residence is curtailing its load.

Another option involves mounting a commercially available sensor to the 'dumb' electromechanical or digital meter to track consumption. These sensors attach to the outside of the meter to read current usage either from the spinning disc (analog) or LED port (digital), and then transmits the readings on a periodic basis to the smart thermostat or home energy gateway via the HAN. Some smart thermostats and home energy gateways are capable of storing these readings for an extended period of time, and transmitting the data to the utility via the Internet-HAN gateway. While such a configuration may not constitute official interval data for billing purposes, it could be used to calculate the level of rebate or adjustment based on actual usage, as well as to provide verification during periods of peak demand.

Of course, some consumers may not even need a financial incentive to do what is just the right thing to do for the benefit of society – and the planet. Several surveys have identified and characterized consumer segments whose members are quite willing to make changes to their energy consumption for the environment. These include the Anything Clean and Ultra Green segments identified in the 2011 Energy + Environment Study by Market Strategies International, and the Concerned Green and Young America segments identified in the 2011 Consumer Pulse and Market Segmentation Study conducted by the Smart Grid Consumer Collaborative (SGCC). The SGCC study also found that 78 percent of respondents strongly or somewhat agree that the smart grid and its energy-saving enhancements would better protect the environment and help make the U.S. more energy independent. And for many in these consumer segments, that may be incentive enough.

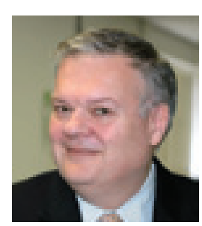
Astute readers may be wondering what happens when a home with an Internet-HAN gateway eventually gets a smart meter with a built-in HAN? The latest version of SEP 1.1 (technically version 1.1.1) includes a provision for more than one Energy Service Interface (ESI) into the home. Support for multiple ESIs enables a smart meter and an Internet-HAN gateway to coexist, thereby providing two-way communication via both the AMI and the Internet at the same time. This allows real-time meter information to be available not just to the utility and devices connected directly to the meter's HAN, but also to customer portals and mobile apps via the Internet-HAN gateway.

Conclusion

Advances in home energy management solutions, combined with the ubiquity of the Internet, mean that utilities no longer need to depend on the deployment of, or features in, smart meters and advanced metering infrastructure networks to implement residential demand response programs. These same alternative configurations could also be used with small businesses, which could control both the HVAC system and other loads with some of the more sophisticated smart thermostats or 'home' energy gateways available today.

So why not at least explore these alternatives with a trial or pilot program? The pilot could be used to reach those areas where the AMI has yet to (or may never) be deployed, such as in a sparsely populated area. Or, use the Internet-HAN gateway to read interval data via HAN-equipped smart meters to supplement or backup the AMI network. I, for one, would welcome hearing from anyone who is doing the latter, and I suspect others in the industry would be equally interested!

About the Author



Louis Szablya is vice president of marketing and utility solutions at Energate, Inc., where he is responsible for marketing, product management, business development and partner programs. Mr. Szablya's areas of expertise include utility resource planning, power system operations, financial analysis, transaction structuring, modeling, marketing, rate strategy, consumer devices, product management, market analysis, and strategic planning. Since graduating in electrical engineering in 1979 his 30-plus years in the energy industry have spanned many diverse jobs, including 15 years at a utility, providing him with a wide range of technical, commercial, contractual, and policy experience.

The Perfect Storm in Transformer Maintenance

By Bob Rasor, SD Myers, Inc.

Transformer management, testing and the resulting diagnoses and recommendations are said by some to be at a crossroads. Today's many adverse factors, if not corrected, are forming 'a perfect storm.' Some of these major storm factors include:

- Aging fleet of transformers presently in use
- A changing workforce within the industry due to the retiring of transformer specialists
- Hesitation or budget restriction to adopt new tools or adapt to new technologies
- Inadequate frequency of testing
- Lack of testing comprehensiveness
- The sometimes insufficient or unknown quality of service specialists for service work.

Four of the most critical factors include:

1. Higher than expected failure rate of an aging fleet of transformers

Although robust in their capacity for overloads, older aging transformers are predicted to fail at higher rates due to the deterioration of their cellulose insulation, bushings and overall old age. They are becoming less and less reliable or capable of meeting the needs of their capacity requirements, especially when subjected to surge events. These older transformers – most of which were built in the '70s and '80s and still predominate – were designed and built without the foresight of electronic monitoring. Today's lighter and more compact transformers more commonly feature electronic monitors.

It is important to recall that moisture, heat, and oxygen are the three elements that promote premature aging of the insulation. They do this individually, as well as collectively, by the formation of acids and other products that are aggressive towards the cellulose insulation.

New transformers, especially the larger ones, are rigorously confirmed at both the factory and the site. This is just the beginning of a responsible maintenance program that would include fluid testing as often as quarterly and regularly scheduled electrical testing.

2. Steady decrease in transformer expertise to build, maintain and service power transformers

It is a fact that many technical and skilled workers that truly understand the ins and outs of power transformers are approaching retirement. Their important skills and talents are fading from the work force. This diminishing resource includes electrical engineers who in past decades had selected this field of study in college, but now are pursuing more alluring careers in new fields like smart-grid automation and computer science.

Concerning manufacturing and repair, designing and fabricating transformers is a labor-intensive activity requiring special skills acquired from years and years of hands-on experience. There are simply too few mentors providing the necessary apprenticeships. Training costs have also risen.

Online testing and monitoring trends help determine 'dry-out' as an effective solution for transformer's life extension

Measurement of data online proved critical for maintaining the working condition of the transformer fleet owned and operated by Northern Lights Electric Cooperative (NLI) in Sagle, Idaho.

NLI manages its transformer testing data through SD Myers, Inc. (SDMI) Transformer Dashboard, a web-based service with access to all testing data 24/7 and a multitude of charting data displayed graphically with the touch of a button. Through this data interface, SDMI's diagnostics group and engineers were able to notice the trending problem with one of NLI's major 230 kV, 5,000-gallon substation transformers.

A report generated by Transformer Dashboard charted a pattern of unacceptable moisture saturation levels in the transformer oil, with the water content in the oil at times exceeding 50-60 ppm. The percent saturation level was important because it reflects the potential for moisture-related failure. Also, over 100 times more moisture resides in the paper insulation than in the oil. Parts per million levels may be low and appear acceptable at lower temperatures, but this can be misleading, because the percent saturation is high under these conditions. Based on the report, NLI was able to determine the best route to extend the life of its problem transformer.

NLI applied an SDMI's DryMax transformer dehydration unit to dry out the oil and paper insulation. Subsequent trending showed that moisture levels were reduced to acceptable 10 ppm levels during the first month. After eight months, the dehydration unit reduced the water content to 2 ppm, with a now acceptable level of relative saturation of under 3 percent. The moisture problem was solved due to SDMI's and NLI's ability to observe trending data, verify the condition and NLI's management decision to correct the problem.

About the author

Clint Brewington, System Engineer at Northern Lights Inc. (NLI) in Sagle, Idaho.

The labor force committed to maintaining and servicing these transformers is experiencing the same labor and skills shortages as the fabricators working in the shops. This includes special skills in fluid processing, electrical testing, vacuum filling, and oil testing – skills that can take years to develop including rigid safety requirements.

3. Transformer testing providers with limited scope of expertise

The Institute of Electrical and Electronics Engineers (IEEE) C57 standards have recommended that transformers rated above 500 kVA be electrically-tested annually. In actuality, this recommendation is often overlooked; and in practice, most transformers are tested every three to five years. Some owners have even extended electrical test intervals out to six- and eight-year cycles.

Often, when it comes to assessing the current condition and 'expected life' of transformers, fluid testing is the only analytical and diagnostic tool employed. While they might appreciate the influx of work, fluid-testing labs are not purposely leading owners/managers into believing that fluid testing is all that is needed to assess their electrical equipment condition. Even though fluid testing is essential, these economical and important tests do not provide the total picture. It has been noticed, however, due mostly to budget considerations, that if the more expensive electrical tests do not seem urgent, then fluid testing is continued on schedule with electrical testing called upon only if an abnormality surfaces.

In addition, the quality of sampling and testing procedures is often lacking if industry standards and best practices are not complied with closely.

The following are some important qualifiers to consider when engaging fluid-testing labs:

- Do sampling technicians record the fluid level, pressure/vacuum gauge reading, top gauge temperature and sample temperature?
- Do they note the paint condition and the presence of any leaks? These are simple tasks that should be performed during any routine inspection or fluid sampling.
- Do sampling technicians extract a representative sample of the dielectric fluid? Are the proper sampling containers used?
- Do the laboratories test for and trend the acids, oxidation, contaminants, oxidation inhibitor, moisture, dissolved gas, and furans?
- Do the laboratories provide testing and maintenance recommendations based on the fluid test results and their trending over time?

As noted earlier, in many power delivery settings, electrical testing is neglected past recommended intervals. These tests are important in determining the health of the transformer and remedial actions required to assure reliability and extend life. Electrical testing can be used to determine if internal inspections are needed. Such inspections may reveal internal issues depending upon the location of the problem.

The following electrical tests provide critical information on the health of the transformer:

1. Doble power/dissipation factor testing
2. Excitation/winding resistance/TTR/Megger testing
3. Power factor testing of the bushings
4. Hot collars testing of the bushings and arrestors

Transformer Specialist Certification Program contributes to Hawaiian utility expertise

John Emmons was a Predictive Maintenance Specialist at Hawaiian Electric Co. (HECO), Pearl City, Hawaii, when he became certified as a Master Transformer Specialist at SD Myers' Training & Education Center, Tallmadge, Ohio. HECO is Hawaii's main utility serving 95 percent of the state's 1.2 million residents.

"The knowledge and wisdom I acquired through SD Myers, Inc. (SDMI) Transformer Specialist Certification Program gave me the confidence to take on more challenging tasks within my company," Emmons explained. "SD Myers provided an in-depth learning experience that I could not find anywhere else. The program elevated my level of knowledge of transformers well above where I had been. I was able to widen my scope of plant operations and maintenance, which ultimately led to a promotion to Resource Planner."

Emmons recommended to HECO management that the rest of his crew could benefit from knowledge similar to what he had received. The utility agreed and SDMI flew in a team to Hawaii, administering instruction and on-site training to 32 additional HECO staff.

About the author

John Emmons has been with the HECO for just under four years. He came to the utility after nearly 11 years with Aloha Airlines working as a lead aircraft electrician assigned to the inspection, troubleshooting, and maintenance of their fleet of Boeing 737-700 and 737-200 series commercial jets. Prior to that, John spent 20 years in the United States Air Force as an avionics technician working on trainer, fighter, and cargo military aircraft. He is a proven manager, administrator, planner, and trainer.

5. Measuring the leakage current of the arrestors
6. Sweep Frequency Response Analysis (SFRA)
7. Partial discharge testing
8. Leakage reactance testing
9. Frequency domain testing

At the end of the day, what's really needed is a transformer maintenance provider that offers more than oil sampling and analysis. Additional expertise is required in electrical testing, moisture management, oil processing and reclamation; and ancillary components such as bushings, arrestors, de-energized tap changers (DETCs) and load-tap changers (LTCs). Such broad expertise is needed for a full and accurate view of the transformer's condition. This data can be powerfully presented in organized, electronically-accessible ways and utilized as a 'dashboard' to help maintain reliability.

4. Slow or non-adoption of modern monitoring and data management tools

Generally speaking, utilities are known for embracing proven, new technologies in monitoring and data management. Increasingly, monitoring and data management equipment manufacturers are developing better quality instruments more effective in detecting such problems as excess moisture and dissolved gasses. Some of these types of monitors can detect moisture plus fault gasses from partial discharge, general overheating, hot-spot overheating, and arcing. Often such monitors can be remotely monitored via the Internet and provide alarm notifications. These systems provide timely and valuable information to implement appropriate action. Always important to these data and their evaluation is the historical trending.

According to Powell Industries' PowlTech division, online electronic monitoring is becoming increasingly more prevalent with the communication advancements of intelligent electronic devices (IEDs) such as electrical metering and protection relaying devices. These advancements have given plant personnel the ability to see into the window of their electrical system to maintain continuous power and determine the cause of, mitigate and predict electrical issues. In general, transformer automation deals with the replacement of analog measurement, protection, and control mechanisms with electronic devices. These instruments, which include IEDs, digital fault recorders and power quality monitors, typically attach to transformers.

Advancements in online data management and trending analysis, real time data collection and product availability are continuing the revolution in which many utilities and owners may still choose to join. This technology can give owners and utilities the ability to automatically retrieve and process the vast amounts of data needed to make decisions that directly reduce operating costs and improve T&D reliability. The alternative is testing data still stored in hard-copy reports, which are prone to infrequent review.

The ability to generate customized electronic reports offers considerable benefits. Departmental needs – from reliability to maintenance to capital planning – often vary in terms of what level of reporting is required on a particular power unit. Therefore, the ability to provide customized reports electronically becomes important. Analyzing the data and presenting that information to the appropriate personnel adds to overall efficiency.

A worthwhile goal may be to get owners to convert paper reports to on-the-spot online electronic access to critical transformer and related equipment analysis. It is important to invest in the new tools that assist in sorting, viewing, printing, and managing information.

Conclusion

Meeting the growing demand of the power grid, while at the same time maintaining system reliability with an aging transformer fleet, requires changes in the way owners operate and care for their transformers. The ongoing challenge for engineers and those responsible for maintenance is to predict the future reliability of their transformer fleets and be better informed about when to act with corrective maintenance or even replace a troubled unit. This is complicated in an uncertain economy that often demands delays in major capital investments. A well-planned strategy and condition assessment with the proper tests, testing procedures and adoption of modern monitoring and data management tools will greatly contribute to the health and reliability of the transformer fleet.

About the Authors

Robert T. Rasor is the Director of Engineering at SD Myers Inc. (SDMI) where he currently leads technology for SDMI's Engineered Products Group and is a regular instructor for SDMI's Transformer Certification Program. He has a Bachelor's Degree from the University of Akron and is a registered PE in the State of Ohio.

John Lioces, SD Myers, Inc. Senior Product Specialist with key input from Clint Brewington, NLI Systems Engineer. John has over 20 years of experience in field services/engineered products working closely with systems experts from utilities across the U.S., focussing on transformer maintenance.

Managing Outages and Keeping Crews Safe in Severe Weather

How the Largest Utility in Texas Responded to April 2012 Tornado Outbreak

By Jeff Johnson, Chief Long Range Forecaster and Chief Science Officer, Telvent DTN with Kyle Stuckly, Business Continuity Consultant, Oncor

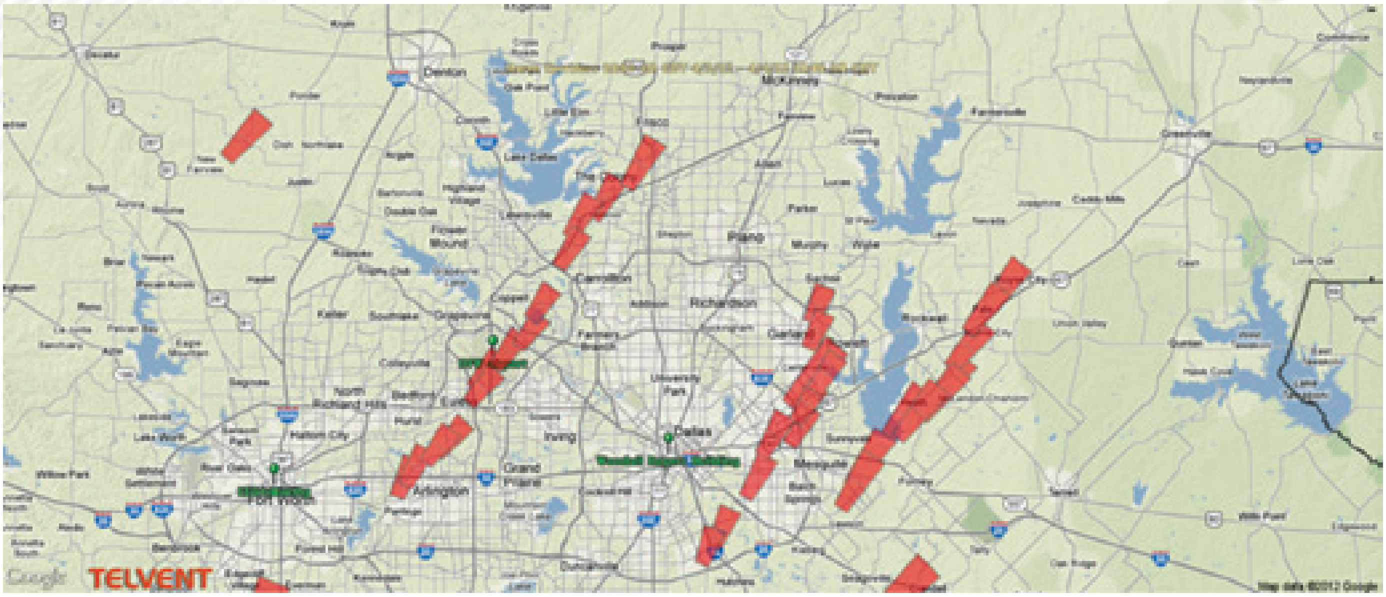
In Texas, the question isn't if severe weather will hit, but when – so utility companies need to be on the alert for the formation of severe weather and preparing for potential outages. In April of 2012, Texans were hit by an outbreak of tornadoes in the Dallas-Fort Worth metropolitan area. A low pressure system started tracking across the Southern Plains on April 3, and what was initially believed to be a wind and hail event developed quickly into a tornado outbreak over a heavily populated urban area. Twenty-two tornadoes formed that day, including an EF3 rated tornado in Forney, Texas that devastated a subdivision and a school. An estimated 1,100 homes were damaged and at least 349 were destroyed. Remarkably, no one was killed and few injuries were reported.

Oncor, the largest electric distribution and transmission system in Texas, found itself in the midst of a major weather event with outages impacting customers across their service area. With more than three million residential and commercial customers and approximately 118,000 miles of distribution and transmission lines throughout central Texas, Oncor was heavily impacted by the tornado outbreak. From April 3 to April 4, Oncor's power grid suffered more than 1,500 interruptions, affecting nearly 150,000 customers. The peak outage occurred on the afternoon of April 3, affecting more than 40,000 customers. The longest outage was one day, four hours and 23 minutes, with 26 million customer minutes of interruptions. Overall, there were 82 feeder outages, 472 fuse outages, 47 recloser outages, 609 transformer outages, 25 switch outages and 385 service outages.

The utility needed to restore power to affected customers as quickly as possible while keeping an eye on crew safety as storms still racked the area. Accurate and up-to-date weather forecasts were a key method for Oncor to help maintain system reliability as well as protect its crews as they brought back power to its customers. The utility relied on Telvent's MxVision WeatherSentry® Online Utility Edition to mitigate and respond to the April storms and other severe weather risks. The advanced, web-based weather information platform helps anticipate potential outages due to severe weather and lightning strikes to reduce service interruptions, and better schedule and protect crews. The subscription-based service provides comprehensive real-time weather data that's tailored specifically to the needs of utilities. Enhanced radar and alerting capabilities that include real-time information allow utilities to monitor weather for a specific location.

"Oncor uses Telvent's MxVision WeatherSentry to monitor current weather and geographical information," says Oncor Business Continuity Consultant Kyle Stuckly. "This information allows our operating centers to request additional personnel during severe weather events to maintain quality service and ensure proper response time." Crews are ready and in place to respond to the aftermath of severe weather and restore power to customers as quickly as possible. Detailed weather and geographical information allow Oncor to make decisions about which service areas are now clear of major weather events and are safe for crews to undertake repairs.

Tornado outbreaks like the one in April of 2012 are an ongoing threat faced by utilities operating in Texas. Severe thunderstorms can occur in Texas in just about any month, but the greatest number of severe storms is seen from March through June. The summer months see severe weather spawning from hurricanes and tropical storms from June through November, with increases in the fall due to more potent cold fronts.



April 2012 Texas Storm Track

For Oncor, lightning is the number one cause of power outages. Using Telvent's real-time lightning feature and radar imaging, Stuckly says, "Oncor is able to improve its ability to safely respond to storm outages and improves customer relations by more accurately projecting estimated times of restoration. Estimated times allow Oncor customers the ability to safely await restoration during extreme conditions or extended service interruptions."

Real-time lightning detection is based on a continual feed of lightning strike data from the Vaisala North American Lightning Detection Network (NALDN®). NALDN sensors measure high and low frequencies of cloud-to-cloud and cloud-to-ground lightning strikes. The proprietary technology uses GPS time-of-arrival and magnetic direction from true north to optimize detection and location of events. Vaisala's Network Control Center ingests the raw data and calculates strike positions and related data such as strike amplitude and polarity, which is then transmitted to MxVision WeatherSentry Online. Oncor can then see the lightning detection displayed along with weather radar, which gives them a good sense of whether or not a line of storms is approaching. By basing lightning predictions on actual lightning presence, Oncor doesn't deal with false alarms and has a highly accurate view of what is being impacted.

Through its advanced weather service, Oncor is able to select weather data that is most important to its operations, like thunderstorms, which get displayed on one centralized weather map.

The location-specific forecasts, which can range from an entire region down to individual roadways, allow Oncor to closely monitor assets, transmission lines, and boundaries. Conditions are anticipated up to 15 days out, with hourly outlooks for the first three days. Forecasts are updated hourly with the best, most current weather forecasts. Wind speed, chance of precipitation, and more can be viewed as graphs, radar images, or on high-resolution street level maps to provide the ultimate view of operational conditions.

MxVision WeatherSentry's high-resolution street level maps display color-coded storm corridors, winds and lightning for a complete view of approaching storms, telling utilities at a glance what conditions are associated with each storm (like large hail or tornadoes). The tracking system shows where severe weather is, where it is heading over the next thirty minutes and what time it will reach locations in its path.

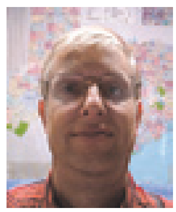
To best prepare for severe weather, utilities need to know what will most likely happen based on current weather conditions at exact locations, so it can be ready for potential outages. Real-time decision making is facilitated by customized weather alerts. These alerts are set-up to notify Oncor when predetermined thresholds have been met; helping utilities best position their crews. An example would be Oncor monitoring a newly formed storm in its service area. The storm may start off with light rain and wind gusts but if it intensifies, an alert will inform staff that it's no longer safe to work. At this time, managers can get crews to safety while also making the necessary preparations to quickly begin restoration efforts after the storm passes.

Mobile weather apps allow Oncor crews to stay on top of changing weather conditions whether in the office or out in the field. Roaming weather information and customized notifications are delivered instantly using the phone's GPS location. Meteorologists are available to Oncor 24/7 for consultations online from computers and mobile devices. The energy provider also has access to questions and answers posted by users across the country, as well as twice-daily forecasts tailored to their region.

Stuckly says, "Through the use of Telvent's weather data, Oncor is able to improve its ability to safely respond to storm outages and improves customer relations by more accurately projecting estimated times of restoration." Oncor and utilities large and small across the country rely on quality weather solutions to save dollars, improve outage response time and, most importantly, keep crews and customers safe during severe weather events.

About the Authors

Jeff Johnson is the Chief Science Officer for Telvent DTN. Johnson graduated with a Bachelor of Science degree in meteorology from the University of Wisconsin in Madison. He became an American Meteorological Society Certified Consulting Meteorologist in 1993. His experience in meteorology comes from over 30 years of weather forecasting for various industries including Energy, Aviation and Transportation. Johnson focuses on medium and long range weather forecasts for Telvent DTN. Contact Telvent at 800.610.0777



Kyle Stuckly (*Kyle.Stuckly@oncor.com*) is a Business Continuity Consultant at Oncor and a registered Professional Engineer in Texas. He is responsible for Emergency Preparedness Plans such as Emergency Restoration, System Emergency Operations, Network Emergency, and Black Start. Additionally, he maintains Oncor's System Operation Center in Dallas, Texas. Kyle has 20 years with Oncor in Distribution Design, Distribution Operations Center support, and his current role since January 2007.

EPRI's Transmission Assets Inspecting Robots Enter Next Phase

By Andrew Phillips,
Electric Power Research Institute

Robotic technologies are an innovative way to assist utilities in their asset management programs. The Electric Power Research Institute (EPRI) is developing robots that will inspect transmission lines and insulators for overhead transmission lines.

A Robot for Transmission Line Inspection

Overhead transmission lines are among the utility industry's most widely distributed assets. In the U.S. alone high-voltage lines run more than 150,000 miles, often in remote locations. Reliability requirements, com¬ponent aging, clearance and right-of-way inspection compliance drive the need for thorough, timely inspections along the entire length of these lines. Such comprehensive assessments by maintenance personnel, working on the ground or in aircraft, currently entail significant expense.

To expand inspection capabilities and increase cost-effective¬ness, EPRI is developing a transmission line inspection robot that can be permanently installed on these lines, and traverse 80 miles of line at least twice a year, collect¬ing high-fidelity information that utilities can act on in real time. As the robot crawls along the transmission line, it uses various inspection technologies to identify high-risk vegetation and right-of-way encroachment, and to assess component conditions.

After an initial concept design, the EPRI research team refined the design and developed a prototype robot. Nicknamed 'Ti,' EPRI has put the prototype through a series of tests at its laboratory in Lenox, Massachusetts and is compiling data that will lead to further refinement of the design.

Features and Functionality

Ti uses high-definition visual and infra-red spectrum cameras with advanced image processing to inspect the right-of-way and component conditions. It will be able to determine clearances between conductors, trees, and other objects in the right-of-way. The cameras also will be able to com¬pare current and past images of specific components to identify high-risk conditions or degradation. As an alternative to the camera, the robot may be equipped with a Light Detection and Ranging (LiDAR) sensor to measure conductor position, vegetation, and nearby structures.

Ti will transmit key information to utility personnel, with a global positioning system accurately identifying its loca¬tion and speed. Another system will collect data from remote sensors deployed along the line, and an electromagnetic interfer¬ence detector will identify the location of discharge activity, i.e. corona, or arcing. Where discharges are identified, field personnel may do further inspections using daytime discharge cameras.

The conductor-crawling robot has been designed to work with a variety of EPRI-developed radio-frequency sensors that can be placed along transmission lines to provide real-time assessment of components such as insulators, conductors, and compression connectors. These sensors will likely be deployed in areas of environmental stress or where specific component types have been installed. For example, lightning sensors will be installed in high-lightning areas, vibration sensors will be used in high-wind areas, and leakage-current sensors will be deployed in coastal areas to detect salt contamination.

The deployed sensors will collect data continuously, develop histograms, and determine maximum values. Data will be transmitted to *Ti* when it is in close proximity and will then be transmitted to maintenance person¬nel. The inspection robots, when coupled with these sensors, will be able to provide comprehensive, accurate, and useful informa¬tion to optimize line maintenance and improve transmission reliability. In some cases, the purchase of robots for use in place of maintenance crews could shift O&M expenses to capital costs, allowing a return on investment and depreciation.

In the field, the transmission line robot will be permanently installed on a transmission line shield wire. It traverses structures and obstacles, e.g. marker balls, utilizing bypass systems that are permanently installed on the transmission line. The robot automatically disconnects itself from the shield wire and connects itself to the bypass system. Once it is has bypassed the obstacle or structure it then returns to the shield wire. These bypass systems could be installed during construction or be made integral to the line hardware. It is envisioned that the robot's mobility could be developed to remove the need for by-pass systems, enabling its deployment on existing transmission lines.

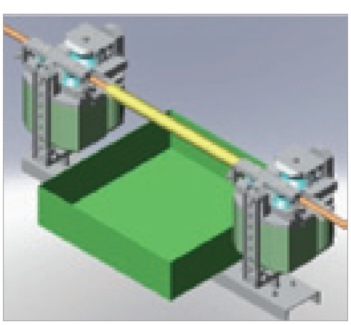
Although *Ti* may be permanently installed on long transmission lines it can be relocated if required to other transmission lines or it may move from one line to another utilizing a bridge that is installed on nearby structures.

The current version of the robot is designed to inspect an average of 12 765kV structures and spans per day. It is capable of moving up to five miles per hour if it needs to reach a portion of the line more quickly, for example to inspect a line outage. The robot draws energy through power harvesting and stores it in onboard batteries.

Stages of Transmission Line Robot Development

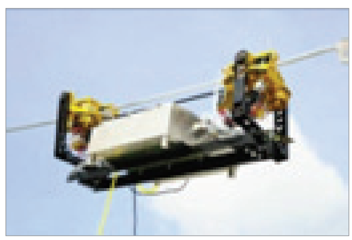
This research, development and demonstration project began in 2008 and is targeted to result in a field implementation in 2014.

Concept – Initial requirements for the robot developed based on industry knowledge and feedback from utilities. The bypass system, solar panels, sensor package and power requirements were a key emphasis in the concept development design.



Design – A detailed design was performed of both the robot and the bypass systems. Details of mobility as well as the integrated sensor, control and communications package were developed.

Technology Demonstration – Technology demonstrators of both the bypass systems and the mechanical components of the robot were constructed, tested and refined. Testing was performed on indoor short sections of line with bypass systems installed.



Full Scale Laboratory Testing – A test loop was developed where all the challenges that the technology demonstration robot would encounter on a typical 765kV line were simulated (angles and inclination). Bypass systems were developed for each of the challenges, and then refined and installed. The robot was then tested and evaluated as it faced each of the challenges.

Remote RF Sensor – A suite of RF integrated sensors has been developed to continually assess the condition of components and transmit to Ti when it is in close proximity. Leakage current, conductor temperature, vibration, lightning and fault sensors have been developed and are currently being demonstrated at 12 sites.

Bypass System – The Heart of the Technology

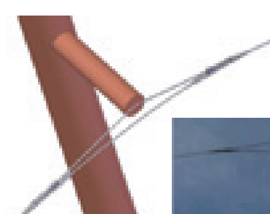
One challenge in developing the robot was to create a design that would enable it to move along the shield wire of transmission lines and move past a structure or other obstacles in its inspection path. *Ti* utilizes bypass systems that are permanently installed on the structure and around objects.

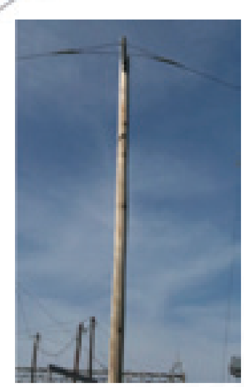
EPRI is testing six systems that will use an additional short section of shield wire by which the robot can bypass the tower structure and other obstacles with no operator input as it makes its way to the next line section. These may be in addition to the normal line hardware or built into the normal line hardware.

For new transmission lines the cost of the additional or modified hardware is negligible compared to the overall cost of the transmission line.

Development of Test Site

To validate the robot's and bypass systems' performance, EPRI constructed a test site at Lenox, MA. This 'Loop' simulates the most challenging situations that the robot would encounter on a 765kV transmission line shield wire. A range of angles and inclination combinations as well as different configurations were designed into the Test Loop.

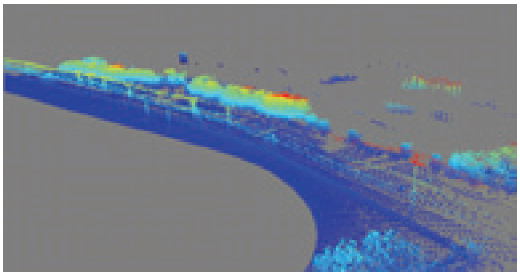




Review of Ti Robot Performance and Findings

Mobility: A robot and a bypass system test area have been built and undergone a series of tests both indoors and on the Loop. The technology demonstration robot was able to navigate all of the challenges of the test loop multiple times without operator input. Important insights were obtained that will result in design improvements, and researchers gathered data on power usage and battery performance.

Sensor Package: A suite of four remote RF sensors from which the robot will collect data are being tested at 12 utility sites ranging from 138kV to 345kV. These tests will result in new improvements and developments for the robot. Initial test results of the LiDAR sensor show great promise. Below is an example of an image generated by this sensor.



Colors represent the height above ground – the LiDAR measured the distance from the robot using the laser, then with the knowledge of the location works out the height of the objectives above ground.

A detailed sensor and control system architecture has been developed and is currently being implemented. It will be tested and then finally integrated into the robot itself.

Next Steps in Development

Using knowledge from the loop testing, the next generation of robot and bypass systems is being designed and implemented.

In 2011 a third round of successful testing was completed. A range of new features and revisions were tested on the technology demonstrator to assess their performance and lay the ground work for the design and development of the first *prototype unit. Ti* circled the test loop at EPRI's Lenox, MA laboratory over 200 times in a row showing the long term feasibility of the concept. In addition, initial LiDAR and high definition camera testing was completed on the test loop. An electronics package and control system for the robot was developed in 2011 and bench tested.

A vendor has been engaged to commercialize the line hardware for the diverter and bypass systems. Work is underway to integrate this hardware with their existing product line.

Based on the results of testing the first prototype unit has been designed and is presently being constructed. The unit is expected to be tested in the late summer of 2012.

EPRI is working with American Electric Power (AEP) engineers to include the robot and bypass systems on a 138kV transmission line to be refurbished in 2014.

Another Robot for Inspecting Transmission Insulators

As transmission line assets age, utilities are challenged on how to address an aging population of composite and porcelain insulators. An important part of the decision making process is to determine the condition of the present population in-service so that one can determine whether to extend life or replace. In addition it is important for field personnel to evaluate the condition of insulator string prior to performing live work on a structure, even if the live work does not relate to the insulators. The issue is more challenging for composite insulators where limited in-service inspection techniques exist.

Insulator Inspection Methods Today

Existing and emerging inspection technologies to assess the condition of transmission line insulators often require close proximity or contact with the insulator string. EPRI is developing a new inspection technology for composite insulators to evaluate their electrical integrity, which is known as the Live Working NCI Tool. The present version of this new technology design requires the utilization of a hot stick as does the application of hot stick camera technologies. At Extra High Voltage levels this is potentially challenging due to the length of the hot stick required and the impact on the operator. EPRI researchers identified this as an appropriate application for robotics as a transport mechanism for these inspection technologies.

A Robotic Solution

As a result of this need, EPRI initiated the development of an 'Insulator Crawler.' This robot would incorporate the Live Working NCI 'detector technology' and a video camera as a payload. In 2010, a feasibility study and a detailed design was completed, and in 2011, a technology demonstrator, nicknamed 'Ike,' was constructed and remotely tested on I-string, Vee-string, and dead-end de-energized insulators with success.

A camera and an EPRI prototype Live Working NCI Tool, which assessed the integrity of polymer insulators, was then integrated into Ike and tested. It showed very promising results with improved repeatability over measurements made by an operator using a hot stick. Although there is a long way to go on this challenging development, the project is revealing that the use of robotics in the future has significant advantages, including more repeatable measurements, addressing ergonomic issues and increasing safety by enabling personnel to be removed from energized situations.

Features and Value

The insulator robotic technology can enable the implementation of existing and emerging close-proximity as well as contact insulator inspection technologies at EHV voltages, (EHV=extra high voltages 345kV and above). It could lead to a much better evaluation of the insulator and allow the utility to remove the operator from close proximity to energized conductors, leading to increased safety. It can also help to reduce the physical stress on operators, since they would not be required to use a heavy, long hot stick which places significant loads on the operator.

Next Steps in Development

In 2012 the capabilities of the *Ike* robot are being extended with the implementation of mechanical, automation and control improvements. A fully energized test in the laboratory environment is planned by the end of the year.

Recently, the development team conducted indoor lab tests on a new version of the transmission line robot. The new prototype robot is based on the numerous lessons learned with the original Technology Demonstrator that was tested for over two years on the outdoor field test loop in Lenox, the transport system wheel tester, and in the lab. The prototype robot has a fully integrated control, communication, and power system and various sensor systems have been fully integrated into its design, including LiDAR, High Definition video, still images, infrared camera, EMI detector and a weather station. The battery system is now fully integrated into the design.

A new set of prototype line hardware has been developed by a commercial vendor based on their current product offering. The new mechanical design of the robot has evolved based on what was learned from prior tests and addresses this new line hardware design. A new series of outdoor tests are planned for the robot and new line hardware in October 2012. The testing will address robot mobility, control and command operations, communication, and sensor integration.

About the Author

Dr. Andrew Phillips is Director of Transmission and Substation Research. Currently, his research focusses on the Overhead Transmission, Underground Transmission, Increased Power Flow, Substations, and high-voltage direct current (HVDC) programs. His special areas of interest are non-ceramic insulators (NCI), lightning and grounding, inspection and assessment of components, sensor development, and daytime corona inspection. Andrew received Bachelor of Science, Masters, and Doctorate degrees in electrical engineering the University of the Witwatersrand in Johannesburg, South Africa.

Dr. Phillips holds four U.S. Patents and is the author of over sixty journals and conference publications. He is a registered professional engineer (PE) and a member of the IEEE and CIGRE. He can be reached at *aphillips@epri.com.*

New Redundancy Protocols Promise Smarter, More Reliable Power Grid

By Jim Krachenfels, Marketing Programs Manager, Belden Inc.

Smart grid creates a whole new level of expectation for the power utilities. In the past, the power grid's only requirement was to deliver power in sufficient quantity that end users – both consumer and commercial – could operate their HVAC systems, appliances, machines and lights when and as long as they desired. Alternative power generation, two-way communication between users and utilities, and increased use of security and surveillance equipment have all contributed to the data stream that is predicted to reach 75,200 terabytes by 2015.

Increased data traffic, and particularly increased data traffic regarding critical information, requires the higher reliability information networks that are now a part of many, if not all, power utility operations. At the core of power utility information networks are:

- industrially-hardened Ethernet switches and routers
- network management software that provides visibility into the network and redundancy schemes that support rapid recovery for network failures and cyber security
- security devices such as hardwired firewalls
- cables and connectors built to withstand the wear, tear, and noise prevalent in facilities such as substations and as a part of deployment over long distances
- secure, reliable wireless connectivity to support AMR and remote access in terrains that do not lend themselves physically or economically to wired connectivity

The New Power Grid

Figure 1 provides a simplified illustration of the power grid information infrastructure. There are multiple assumptions that can be made:

1. It is easy to see that Internet Protocol (IP) technology is a key enabler of the smart grid because it is standards-based, flexible, and scalable.
2. Hardened switches and routers that can stand up to the demands of the power grid need to adapt to the demands for increased data by supporting greater throughput and also by assisting in intelligent bandwidth-protective routing of information through protocols such as Internet Group Management Protocol (IGMP).
3. New software applications and protocols that support security, optimize routing, and simplify and streamline data management need to be developed. To make smart grid work, it will be necessary to automate much of the managing, analyzing, and visualizing of all that data – allowing humans to deal with the exceptions, not the minutia.

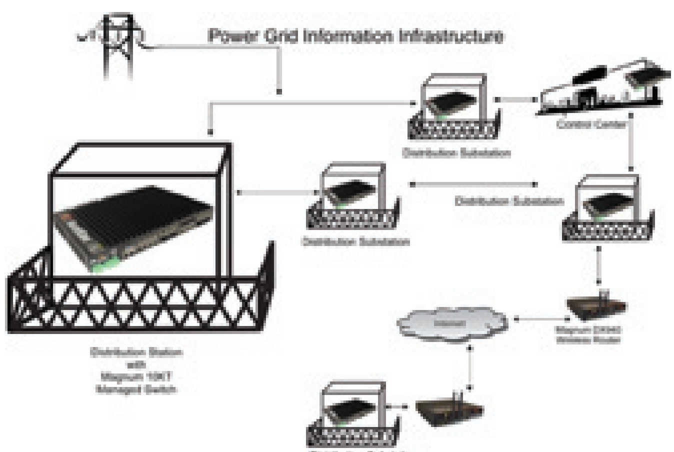


Figure 1: Power grid components are connected in a classic ring structure with single feed spurs

The Search for Zero Failover Performance

One challenge has remained, however, and that is the ability to provide zero failover in the instance of a network failure. Over the years, redundancy protocols have been developed that have significantly reduced the failover time for network failures. The graph in Figure 2 shows details on a number of redundancy protocols, and the rapid decline in typical reconfiguration time of protocols developed this century. Each reduction in failover time meant reduced risk when deploying Ethernet-based data networks in power utility applications.

Protocol		Standard	Typical re-config time	Remark	Available since
STP	Spanning Tree Protocol	IEEE 802.1d	30s	any topology/mesh, diameter limited	1990
RSTP	Rapid Spanning Tree Protocol	IEEE 802.1D-2004	2s	any topology/mesh, diameter limited	2004
CRP	Cross Network Protocol	IEC 62439-4:2010	1s worst case for 512 end nodes	any topology/duplicated networks	2007
BRP	Beacon Redundancy Protocol	IEC 62439-5:2010	4.8ms worst case for 500 end nodes	Two top switches with star, line or ring	2007
DRP	Distributed Redundancy Protocol	IEC 62439-6:2010	100ms worst case for 50 switches	ring, double ring	2010
MRP	Media Redundancy Protocol	IEC 62439-2:2010	200ms 50 switches	ring	1998/2007
Fast MRP	Media Redundancy Protocol	IEC 62439-2:2010	30ms (50 switches) 10ms (15 switches)	ring	2010
Optimized RSTP	Rapid Spanning Tree Protocol	IEEE 802.1D-2004 (configuration requirements described in IEC 62439-1:2010)	5...20ms per hop	ring	2010
HSR	High-Availability Seamless Redundancy	IEC 62439-3:2012-07	0ms	ring	2010
PRP	Parallel Redundancy Protocol	IEC 62439-3:2012-07	0ms	any topology/duplicated networks	2010

Figure 2: The above chart shows the evolution of redundancy protocols and the progress over the last 20 years that has led to the reliable zero failover performance necessary for many industrial applications, including much of the smart grid

Parallel Redundancy Protocol

Parallel Redundancy Protocol (PRP), first available in 2008, and High-availability Seamless Redundancy (HSR), announced in 2010, were the first IEC standard redundancy protocols to provide failover times of 0 ms network failures. Together they offer a new level of reliability for environments such as electricity distribution and security where uninterrupted data communications in environments are a requirement.

PRP uses two separate LAN networks that simultaneously send copies of each frame of data from the originating node to the destination node (collectively, end nodes). The end nodes must be dedicated switches, while other switches in the network remain unaware of the operation of the protocol. The dedicated switches, or end nodes, are called Double Attached Nodes (DANs); the other switches in the network are standard single-network-interface nodes or Single Attached Nodes (SANs). An important characteristic of a PRP implementation is that the two networks involved can have identical topologies, or they can have different topologies and/or different performance characteristics.

Whichever frame reaches the destination node first is accepted and the second discarded, based on interpretation of coding within each frame. As long as one of the LANs is operational, each frame sent would reach its destination, thus zero-time recovery is achieved. To make the system work, each node in PRP has to have two Ethernet interfaces with the same MAC address and present the same IP address. As a layer 2 redundancy protocol, PRP does not require modification in network protocols at layer 3 or greater.

Non-PRP nodes and SANs are attached to a single network and are only able to communicate with other nodes in the same network – or through a Redundancy Box (RedBox).

High-Availability Seamless Redundancy

HSR is a second redundancy protocol standardized in IEC 62439-3. It has been selected as one of the redundancy protocols named in IEC 61850 for use in substation automation.

Much like PRP, HSR networks require a source node to send identical frames over two ports simultaneously to a destination port, however, HSR networks are restricted to a ring topology. Unlike PRP, HSR uses DANs that are connected to each other without the requirement of dedicated Ethernet switches. It is important to note that available network bandwidth is halved, because two frames, instead of one, are transmitted over the ring. In addition, every node in the ring must be an HSR-capable switching end node.

A HSR node receiving a unicast frame with its own MAC address as destination passes the frame to its application layers and discards the duplicate. It will forward a frame recognized as multicast (or broadcast) for further transmission, after uploading its own copy to upper layers. When the frame completes the circuit of the ring, the sender node removes the packet from the ring.

Although HSR uses a ring topology, redundant connections to other networks are possible, as will be illustrated below.

IEC 62439-3:2012-07 – A Turning Point

The original PRP definition, IEC 62439-3:2010, was later amended to align PRP with the HSR protocol. The new version of the standard adopted this year, IEC 62439-3:2012-07, includes descriptions of both HSR and PRP. The alignment of the two protocols makes it easier to implement multi-protocol nodes, including the ability to create a redundant transition between HSR and PRP networks.

Only in the case of multiple simultaneous failures – i.e. both networks (for PRP) or more than one failure in the ring (for HSR) – will there be the possibility of a communications failure.

Application Examples

Figure 3 shows a simple PRP deployment. Recall that PRP is capable of operating with any type of topology. The standard LAN can consist of just a line or additional redundancy technology, such as RSTP or MRP. SANs, which do not require zero-failover levels of responsiveness, attach only to a single DAN and are not a part of the PRP network. This type of deployment might be used to connect two substations using PRP, while non-critical devices within each substation are outside of the zero-failover zone.

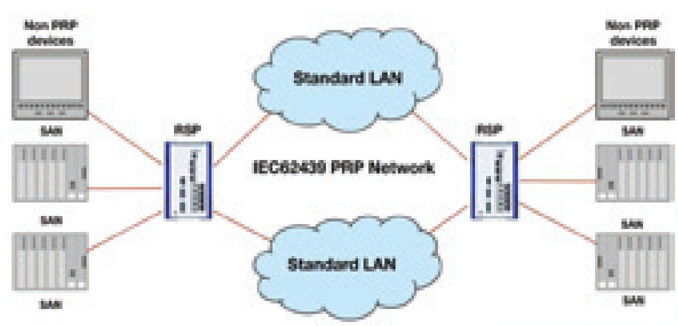


Figure 3: PRP provides zero failover and no packet loss for critical traffic such as 'transfer trip,' 'mirrored bits,' and 'synchrophasor' real-time measurements

Figure 4 shows a more complex version of a PRP network that includes duplicated transmission via a wireless connection and through a PRP network.

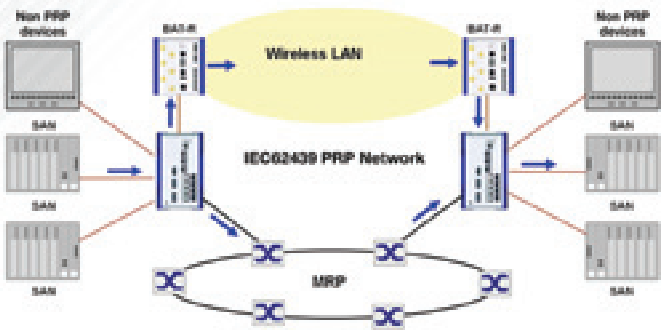


Figure 4: A wireless component may be added to a PRP network while still providing for 0 ms failover and no packet loss

Figure 5 illustrates an HSR application linking a number of substations in a redundant ring. Note that a RedBox is attached to one node on the right to provide access to SANs existing beyond the HSR environment. One set of information packets circulates counter-clockwise (red arrows) while the other set runs clockwise (green arrows). If a packet gets lost due to a cable break or other transmission failure, the second packet will reach its destination without any delay.

An added component in this example is the possibility that instrumentation within some of the substations may use board-level embedded Ethernet switches rather than installing separate switch boxes.

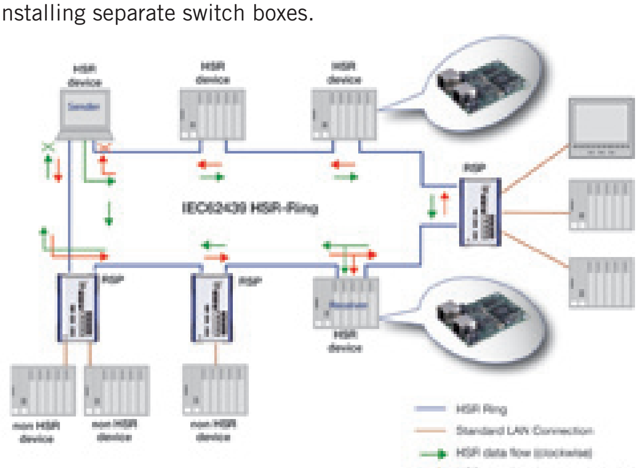


Figure 5: HSR provides the required <4ms timing plus zero failover for quantities of substations networked in a redundant ring

Summary

There is no single 'right' way to implement a smart grid. Solutions are as disparate as the types of utilities and the regions in which they operate. A municipally-owned utility in the Northwest, a public/private collaborative venture in the Southwestern desert, and a rural cooperative in the mountains of Appalachia will all have different operational challenges as well as differing political and financial considerations.

Nonetheless, PRP and HSR offer a new level of flexibility to expand IP networks in power utility transmission and distribution facilities because of their ability to ensure redundancy with zero failover times. Hardened industrial switches capable of supporting these protocols are coming onto the market now that enable smooth integration into existing networks. As mentioned above, new embedded Ethernet boards and chips are also available to support these protocols, allowing for even more flexibility in applications that support the smart grid.

IEC 61850 standards call for intelligent communications networks capable of supporting two-way power utility-independent power generator and power utility-end user communications. With the availability of zero failover networks, smart grid is one step closer to full deployment.

About the Author

Jim Krachenfels directs the marketing communications efforts of the Industrial Solutions Division of Belden Americas Inc. He has more than ten years' experience in marketing programs and product management in the networking industry, including positions at Cisco Systems and SPEEDCOM Wireless. Jim holds a B.A. in Economics from Northwestern University and an M.B.A. in Marketing/Computer Information Systems from the University of Michigan. He can be reached at *jim.krachenfels@belden.com*.

THE BIGGER PICTURE

BY BERNADETTE CORPUZ,
BORDEN LADNER GERVAIS LLP

FIT 2.0 is Live

Approximately one year ago, the Ontario Government launched its review of its Feed-in Tariff Program ("FIT Program"). The Government released the results of its review ("FIT Review") a few months later, March of this year. Over the next five months, after directions from the Minister of Energy on April 5 and July 11, 2012, and following industry comment on the draft rules and contract proposed by the Ontario Power Authority ("OPA"), Version 2.0 of the FIT Program ("FIT 2.0") is now live. Well, almost.

FIT 2.0 – DRAFT RULES TO FINAL FORM – INDUSTRY'S VOICE IS HEARD

The comment period on the draft form of FIT 2.0 rules and contract ("Draft FIT 2.0") ended on April 27, 2012. The final version, expected to be released in early May, was issued in August following the OPA's consideration of industry's strongly voiced comments.

SO WHAT CHANGED

Draft FIT 2.0 provided ample foreshadowing that the revised program would contain more than tinkering amendments. Once industry understood that the lower prices still provided profit opportunity, attention turned to the other significant changes. Most noticeably, the rush to the start under FIT 2.0 will still be tempered by a layered priority ranking system, procurement caps and application windows.

Some significant differences between Draft FIT 2.0 and final FIT 2.0 did emerge. The following is a non-exhaustive list of key differences. FIT 2.0:

1. no longer contains the controversial termination for convenience and stop work order provisions considered to be prohibitive to project development by developers and financers alike;
2. recognizes earlier movers by making additional points available to applicants for applications submitted before certain dates;
3. adds time stamps as a factor considered when an application is being reviewed;
4. provides for the assignability of resubmitted applications in very limited circumstances;
5. introduces the concept of a contract capacity set-aside project which will receive a higher ranking than all other applications;
6. changes the points available in the Aboriginal support category to be applicable only to a small FIT project; and
7. provides an option for an applicant that has entered into two or more FIT Contracts that collectively qualify as a rooftop portfolio, to extend the milestone date for commercial operation to 36 months following each contract date.

FIRST THINGS FIRST – WHEN DO THE DOORS OPEN?

Well, at the time of writing, not quite yet. As we learned in Draft FIT 2.0, the initial open-endedness of the FIT Program will now be at an end and the issuance of contracts now subject to periodic procurement targets set by the OPA in its discretion.

The OPA has posted on its FIT Program web page that the application window for small FIT projects (those 500 kW or smaller) is anticipated to open on October 1, 2012, and close on November 30, 2012. This is consistent with previous direction issued to the OPA by the Minister of Energy. About 200 MW are expected to be awarded.

SO WHO GAINS ADMISSION?

Applications will first be judged on whether or not they meet the completeness requirements set out in the FIT 2.0 Rules. Then each application will either pass or fail depending on whether the application meets the eligibility requirements set out in the FIT 2.0 Rules. Finally, each application will be evaluated to determine whether it qualifies as a contract capacity set-aside project (i.e. an Aboriginal or community participation project with greater than 50% participation level).

Applications will then be ranked by their qualifications as a contract capacity set-aside project, as applicable, priority points, and by time stamp (or a resubmitted application's pre-existing application time stamp). Finally, Applications will, in order of rank, be assessed under the transmission availability test and the distribution availability test (as applicable) and, if it passes and availability remains within the applicable procurement target, an application will receive an offer notice. Whew.

Eligibility Requirements

A number of changes have been made to eligibility requirements, some of which affect specific types of renewable fuels.

Solar – Amendments to land restrictions for solar projects have been introduced. *Ground-mounted solar* projects may not be located on residential property or on property abutting residential property. However, for property where the lawfully permitted use is agricultural, these types of projects are permitted on the property or on an abutting property if residential use is permitted on both properties as ancillary to the agricultural use. Such projects are permitted on commercial or industrial property as long as the project is not the main, primary, or only use of the property. Such projects cannot, with few exceptions, be located on:

- specialty crop areas,
- lands with organic soils, or
- lands with mixtures of class 1, 2, or 3 lands (exceptions exist if the project is on an airport or aerodrome, a closed landfill, a federal military installation, a contaminated property, an industrial property, or, in respect of class 3 soils land, property that is owned by a municipality;
    - a residential property that is not exempt;
    - a property that abuts a residential property unless such resident property is exempt; or
    - a property in respect of which one or more non-rooftop solar projects would constitute the principal use.

Solar (PV) Projects continue to be limited to a maximum of 10 MW.

A *rooftop solar facility* must reach commercial operation within 18 months of receiving a Contract, but if the Facility forms part of a Rooftop Portfolio with more than 15 MW of projects contracted from the same application window, the Applicant can have 36 months to reach commercial operation.

Waterpower Projects – continue to be limited to a maximum of 50 MW.

There are also specific provisions for co-locating projects and limitations on developers submitting similar projects during the same application period. In addition, a proposed project (other than a waterpower project) will need to be located within fifty kilometres of the facility's contemplated connection point.

Application Requirements – Generally

All project applicants, including those with small FIT projects, will need to submit application security under the new Rules. The size of the application security is representative of the size and development complexity of a potential project – either $20 per kW of capacity for solar PV, $10 per kW for other projects, or $1,000, whichever is greater. Lower security rates apply to projects with greater than 50 per cent community or Aboriginal participation.

In addition, an applicant must provide representations and warranties which attest to an awareness of certain project requirements, such as environmental permitting and particular FIT Program Rules, and which confirm that certain preparatory actions have been completed in respect of the project, such as obtaining all access rights and supporting documentation (e.g. independent engineer report, a written opinion of a Land Use Planner, maps, requisite consents and statutory declarations, Environmental Site Assessments, land titles or land registry search, soil study, etc.). The effect is to place a greater degree of responsibility as well as additional costs on the applicant to ensure the viability of its proposed project.

Resubmitting an Application

Pre-existing small FIT applicants who wish to participate in the FIT Program will need to submit a revised application during the anticipated application window (between October 1, 2012 and November 30, 2012) in order to maintain their original time stamp. New and resubmitted applications will be reviewed according to the FIT 2.0 Rules. Applications can be modified to conform but the legal applicant name and location must stay the same to retain the original time stamp. The project must also be located on the same site. However, applicants will be allowed to change the legal applicant name on the application if they are adding participation of 15% or more from an Aboriginal or local community, school, college, university, hospital, or long-term care home.

New evidence and security must be submitted, along with a new application fee; the application fee and security submitted with the Pre-Existing Application will be returned.

Existing applicants who do not wish to proceed under the FIT 2.0 Rules may withdraw their application and they will have their application fees and application security returned.

Any existing application that is not resubmitted within the required window will be terminated and the fees and security returned.

The Priority Points System

Under the FIT 2.0 Rules, a new priority points system will be used to rank applications with the time stamp now acting as tie breaker. An application may only proceed if the proposed project can receive at least one point. The new system clearly assigns priority to projects that have a community, Aboriginal or municipal, education or health sector component, whether as a direct participant in the project or as supporting entity.

PRIORITY POINTS TABLE

PROJECT TYPE	PRIORITY POINTS
Community Participation Project	3
Aboriginal Participation Project	3
Education or Health Participation Project	2
NON PROJECT TYPE	PRIORITY POINTS
Municipal Council Support	2
Aboriginal Support	2
Project Readiness	1
Pre Existing Application Time Stamp is on or prior to July 4, 2011	1
Pre Existing Application Time Stamp is on or after July 5, 2011	0.5
Education or Health Host	2
System Benefit	1

The FIT 2.0 Rules do not permit a project to obtain more than one type of participation project points but do permit certain combinations of project and non-project points under certain situations.

New restrictions around change of control and assignment have been added to ensure that the economic interest and membership levels specified under the project type category (e.g. Aboriginal or community economic interest) do not fall below the level that resulted in the project receiving priority points during the application review process.

Additional points are also now available based on the time stamp of a pre-existing application: One point is available for projects that applied on or before July 4, 2011, and one half point is available for projects that applied on or after July 5, 2011.

THE CONTRACT

Developers will no longer have the option to buy back (by paying liquidated damages) any part of the contract's term lost as a result of failing to achieve the milestone date for commercial operation.

Domestic content requirements remain at 50% for wind projects and 60% for solar projects.

AND SOON THE GATE WILL OPEN

Let's see who will be the fittest of the FIT.

ABOUT THE AUTHOR

Bernadette Corpuz is a Senior Associate in the Electricity Markets Group of the law firm Borden Ladner Gervais LLP (BLG). As a member of the Electricity Markets Group, Bernadette advises a wide range of energy market participants, including distributors, transmitters, generators, and commercial users with respect to a variety of commercial and corporate transactions related matters, including mergers and acquisitions, financing and energy markets. Bernadette can be reached at *bcorpuz@blg.com* or 416-367-6747.

By Mike Baldi,
Honeywell Process Solutions

SECURITY SESSIONS

Staying Ahead of Today's Cyber Threats

In an age where ubiquitous flash drives can become precision-guided munitions and a serious security breach is a single, misguided decision away, the concept of 'defense-in-depth' – employing multiple layers of both physical and cyber security measures – has become a prerequisite for maintaining operations.

The increasing complexity and volume of applications, and the issues stemming from threats to these applications, requires continuously evolving approaches and tools to combat potential attacks. Earlier this year, for example, McAfee reported an unprecedented growth in detected malware and suggested the total number of pieces of malware in their database should exceed 100 million by the end of 2012.

Such statistics further emphasize that the security-threat landscape continues to evolve. So too must the tools that combat those threats.

To that end, one of the more recent developments in cyber security protection is the concept of application whitelisting – an emerging approach used to combat viruses and malware, allowing 'safe' software to operate while blocking other, potentially unsafe applications. The basic concept behind application whitelisting is to permit only good known files to execute, rather than attempting to block malicious code and activity. When properly implemented, it should:

- Enforce a list of approved applications
- Include an administration tool that allows for adjustment to the whitelist, and
- Monitor, block, and report attempts to run unapproved files

With increasing numbers of attempted intrusions, cautionary tales of security breaches, and the potential for resulting damages at various sites, application whitelisting can be an important addition to a utility's security arsenal. But before implementation it is important to understand the security landscape and how whitelisting can fit into a utility's security strategy.

Application Whitelisting 101

Application whitelisting accomplishes its objectives by creating a list of approved software and applications and allowing only those to execute. Email management, for instance, is a common application of a whitelisting technique. Spam is eliminated from inboxes while safe correspondences are allowed access. This approach is in contrast to 'blacklisting' – one approach used by anti-virus software, which is a standard signature-based approach that blocks or removes known harmful software.

Blacklisting, while effective, has a weakness in that it only blocks *known* bad actors – leaving a time gap between the detection of a new piece of malware and the inclusion of its signature in the latest update from the anti-virus vendor. During that time gap, there is a window of exploitation where a system may be vulnerable to the new malicious code. Malware examples, such as worms and trojans, utilize signature-morphing methods that can bypass traditional anti-virus detection. Application whitelisting does not depend on known malware signatures, so it provides greater protection against new malware without requiring signature updates.

While the general concept of whitelisting is simple, integrating it into an industrial control system (ICS) can be risky. Whitelisting must be tightly integrated into an ICS and thoroughly validated so that it does not impact performance or block critical system functionality under any circumstances. With this in mind, it's possible to enable whitelisting technologies in a monitor-only mode, allowing for a managed, low-risk approach to incorporating whitelisting protection on an ICS.

And with the cyber security landscape quickly evolving, so too must an approach like application whitelisting. Forward-thinking whitelisting advocates, for instance, are looking at advancements in whitelisting as a way to quarantine unauthorized software upon discovery and after blocking, and produce a file system inventory that can accelerate verification of software on a hardware platform.

Components like USB and CD/DVD device protection, registry protection and other malware-oriented defenses help expand the reach of application whitelisting technologies. This growth helps utilities and other facilities in the energy and power space stay ahead of the curve when responding to potential security threats.

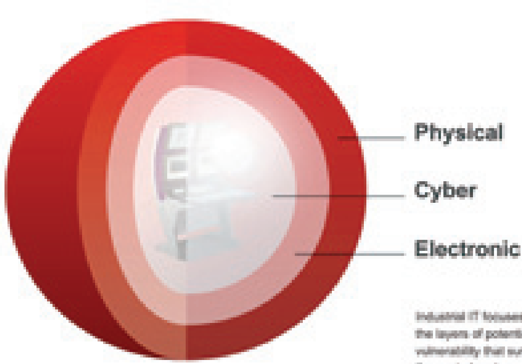
Including the IT perspective

Whitelisting was designed and architected for the enterprise or business IT environment. However, priorities for operating in a business IT environment are different than those for an industrial control system. Confidentiality, integrity, and availability of data, for instance, are primary concerns in defining the security of a system, and maintaining data confidentiality and integrity are the highest priority requirements for a business IT environment. Conversely, on an industrial control system data availability is the highest priority, which provides some unique challenges for whitelisting deployment including:

- High availability requirements of the system – limited update opportunities
- High risk of changes impacting process operation – slow to implement patches and updates
- Industry and government standards compliance requirements
- Legacy systems running older operating systems

Therefore, business IT security solutions which are deployed on industrial control systems have to be adjusted to accommodate the operational requirements of an ICS. Industrial control system sites must find a way to merge the business IT practices and ICS system requirements.

There are several approaches in getting the IT and control systems departments on the same page. Cross mingling departments, for instance, is an effective method of ensuring successful communications. Assigning IT workers to the process engineering department and vice versa can help the two organizations come to a better understanding.



Industrial IT focuses on the layers of potential vulnerability that surround the control system.

Activities designed to bring the two groups closer is also effective. Seconding an IT worker to the controls group allows them to gain a different perspective and appreciate the priorities of engineering and, when the seconded employee rotates back to the original IT group, they will bring a shared experience with added perspective. Situating the two groups in the same room and including both groups in meetings can also promote cross-group harmony.

By sharing information, collaborating and communicating between both IT specialists and process engineers, companies can achieve solutions that incorporate a bevy of viewpoints and better protect themselves against costly safety and security incidents that impact their bottom lines.

Where Does Whitelisting Fit in the Lifecycle?

It is also important to understand where whitelisting fits in with the utility's industrial IT lifecycle. Taking a logical approach to managing this lifecycle is key to securing the critical infrastructure.

This is a process with four distinct phases – assessment, remediation, management, and assurance. Each phase in the lifecycle is important, but the assessment phase is perhaps the most revealing. Assessing assets and vulnerabilities against industry standards and best practices provides a roadmap to eliminating or diminishing revealed areas of risk.

During the assessment phase, the applicability, deployment strategy, and proper selection of technologies like application whitelisting will be defined. In future assessments the effectiveness of the protection technologies will be evaluated to ensure they continue to meet the site's security needs.

The remediation phase begins by addressing vulnerabilities and alignment with industry standards and best practices. A custom-designed security program is one of the deliverables from this phase. This is the phase of the security lifecycle in which application whitelisting and other protective technologies will be deployed.

Once remediation has occurred, it is necessary to keep the network and security programs at their optimum level. This activity occurs in the management phase of the industrial IT lifecycle. In this phase, the focus is on preserving and enhancing the investment made in security, by applying services and training. Ongoing management of systems and technology would include workflow implementation, anti-virus and patch management services, network perimeter management, testing, and change management programs.

The assurance phase relies on a compliance manager that provides a single, interactive portal for managing and tracking compliance—such as NERC CIP compliance. Managing and tracking compliance requires the integration of multiple data sources along with the tools and functions that enable the ability to manage and react to change. Real-time data should enable accurate reporting with minimal effort and it is important that the design of application whitelisting technology be configured in such a way as to allow for easy visibility into the reporting tools it has to offer.

Moving Forward with Application Whitelisting

The discovery of the Stuxnet worm in 2010 brought the potential of cyber attacks to the attention of the industrial control system community like no other previous event. 2011 was the year that most organizations demonstrated their readiness to develop and deploy cyber tools as a result of the highly publicized Stuxnet attack. However, other cyber weapons, used to destroy data at any given time, are likely to be more widely used. Programs such as kill switches, logic bombs, and other threats can be developed on a regular basis and deployed systematically.

The challenge for industrial control systems is one of preparation, vigilance, and agility. Part of that preparation is utilizing tools to prevent potential attacks while applying them as part of a broader security strategy. Application whitelisting is one tool that should be used as a complementary security defense. While it does detect attacks that other technologies don't, threats like buffer overflows, SQL injection and cross-site scripting are better controlled when combined with well-suited tools like antivirus programs.

Regardless of the depth of initial usage in control systems, whitelisting is a technology that can provide another layer of defense in protecting industrial process control systems.

McAfee Threats Report: First Quarter 2012. Page 6
http://www.mcafee.com/us/resources/reports/rp-quarterly-threat-q1-2012.pdf

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Guest Editorial

Why Dynamic Pricing is Smart Pricing

By Jason Cigarran, Vice President, Marketing, Comverge

As the industry continues to debate just how to make the smart grid a reality, dynamic pricing programs are receiving increased interest from state commissions and utilities as an important piece to the puzzle. This is driven in large part by an issue the vast majority of utilities across the world have long faced – the fact that the cost of generating electricity does not always match the price the end user pays for that electricity. This is highlighted by recent Brattle Group study that shows how costs are not always equally/fairly distributed. To explain, the study found that consumers on a flat rate pricing plan that don't consume much energy during peak hours, are likely subsidizing heavy peak users to the tune of US$3 billion a year. Collectively, these consumers may be overpaying for electricity by about US$7 billion a year (using the FERC Staff estimate of 92 GW saved under universal dynamic pricing and valuing demand response at US$75/kW-year). Dynamic pricing programs have the ability to solve this issue by enhancing the economic efficiency of energy usage and reducing peak demand, which also limits the need for expensive peaking capacity.

Yet there are several kinds of dynamic pricing programs. To best understand the real-world benefits of each, it is important to understand how they operate:

Real-Time Pricing (RTP)

Real-time pricing enables customers to pay for electricity at wholesale cost during a predetermined interval and is usually targeted at commercial & industrial (C+I) customers who use large amounts of energy. In such a program, a utility will provide prices in advance (usually a day or an hour ahead of the event) and a customer may commit to either reducing an entire load or a portion of that load. This is often viewed as the purest form of dynamic pricing as the much smaller price responsive interval periods lead to a closely linked cost/price ratio.

Critical Peak Pricing (CPP)

Critical peak pricing (CPP) incentivizes users to lower energy usage during peak periods, when electricity is at its most expensive. This provides an opportunity for customers to reduce their electricity bills by choosing to use less energy. CPP is a dynamic rate that it is dispatched by the utility based on real-time capacity conditions. It is one of the most effective approaches to substantively reducing peak demand as I will discuss later on when reviewing results from programs Comverge customers.

Time-of-Use (TOU) Pricing

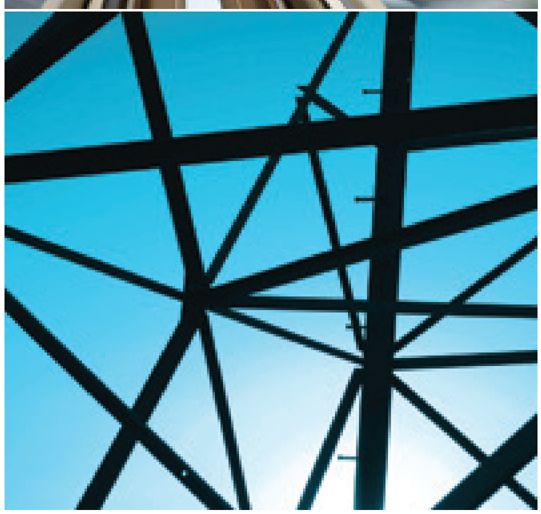
Time-of-use (TOU) programs reflect the higher cost of supply during peak periods, as well as the lower cost during off-peak periods. TOU rates are not widely considered dynamic because they are fixed and not based on actual market conditions. For example, a peak period might be defined as the period from 11:00 a.m. to 5:00 p.m. on weekdays, with the remaining hours defined as off-peak. However, there is certainty as to what the rates will be and when they will occur during these intervals. In other words, these rates are independent of the system conditions and are dispatchable only by the utility. This differentiates TOU from the other dynamic pricing programs but as I will discuss later these programs are still tremendously effective in lowering peak loads and reducing the need for peaking capacity.

Peak-Time Rebate (PTR)

Peak Time Rebate (PTR) programs allow customers to earn a rebate by reducing energy use during hours of peak demand. Rebate payments are based on the amount of load reduction as compared to a calculated baseline usage level. The number of days when the program is available is typically capped for a calendar year.

What to Know When Executing a Dynamic Pricing Program

No matter what type of dynamic pricing program a utility decides to roll out, there are certain technologies and best practices required to make them successful. At the core of any dynamic pricing program is a demand response management system (DRMS). This enables utilities to send customers real-time or day-ahead price signals to a variety of endpoints, including Web portals, programmable controllable thermostats, smart thermostats, in-home displays (IHD), or mobile devices, such as an iPhone.



With these endpoints, customers can manage energy use by changing the settings of almost any appliance, including air conditioners, heating systems, washers and dryers, pool pumps, and water heaters. Typically, dynamic pricing uses either advanced metering infrastructure (AMI) or existing broadband networks to provide fast, reliable two-way exchange of communications between the customer and utility. This two-way exchange, enabled by a DRMS, allows utilities to aggregate all adjustments to a participant's control schedules and offers advanced insight into the capacity made available by all program participants.

With these programs, utilities can maximize the benefits by increasing participation among users. Because dynamic pricing programs are a relatively new concept to energy consumers, utilities are still developing the best marketing approaches to drive program participation. To ensure maximum program participation, the marketing function should include prospect analysis, segmentation, marketing implementation, recruitment, qualification, and enrollment. Ongoing support for program management, administration, field service and installation management, customer support and investment is also important to driving mass-scale adoption.

The program needs to be measured to ensure success. As a result, it is vital that utilities have access to tools that monitor and ensure event performance through measurement and verification (M&V) data, which allows them to evaluate device usage, forecast futures based on past event participation, and ensure ongoing performance. Additional tools for assessing system and network performance – e.g. load and event analysis, forecasting and customer analysis, and class/type segmentation – will provide the necessary analysis for further system optimization.

Customer Successes

It's clear that in theory, dynamic pricing programs have the potential to increase customer engagement and build more meaningful relationships. But how do they really work in practice? Below are two real-world examples from Comverge customers that have implemented dynamic pricing programs that are driving meaningful results:

Gulf Power

Based in Pensacola, FL, Gulf Power is an electric utility that provides services to more than 430,000 customers in Northwest Florida. Gulf Power's commitment to providing its customers with reliable and affordable energy, while minimizing any environmental impact, has earned the company national recognition as a leader in energy efficiency. For the last 12 years the pioneering Gulf Power Energy Select TOU-CPP program, which at almost 10,000 participants is currently the largest automated residential dynamic pricing program in the country, has resulted in customer satisfaction rates of 90 percent and delivered environmental benefits by enabling Gulf Power to lower peak demand, therefore deferring the need to build additional generating facilities.

The Gulf Power Energy Select program gives customers greater control over their energy usage by enabling them to pre-program their central cooling and heating system, electric water heaters, and pool pumps to automatically respond to pricing tiers and price signals. This "set it and forget it" capability makes it easy for customers to participate and also provides a more predictable load drop. The system bypasses the traditional AMI used for dynamic pricing programs to use the customer's existing broadband network and a ZigBee gateway to enable a two-way exchange of information. The program has provided Gulf Power with a highly reliable source of capacity while enabling participants to pay a lower price for electricity approximately 87 percent of the time.

Tampa Electric Company

Based in Tampa, FL, Tampa Electric Company provides service to approximately 672,000 residential and C&I customers over 2,000 square miles of Florida. Inspired by the success of the Gulf Power Energy Select program, Tampa Electric Company implemented the Energy Planner program, a TOU and CPP program with more than 2,000 participants enrolled. One of the most sophisticated residential dynamic pricing programs in the country, Energy Planner enables residential customers to automate control of their energy usage to reduce consumption during times of peak demand, when electricity rates are at their highest.

Tampa Electric Company deployed a cost-effective TOU and CPP program that bypasses both AMI meter data management (MDM) technologies to use a customers' existing broadband network and a ZigBee-based home area network (HAN) to collect and analyze data from energy management devices, smart meters and residential gateways.

In particular, the Tampa Electric Company Energy Planner program uses smart thermostats and digital control units (DCUs) to help residential customers control the operation of central heating and cooling systems, electric water heaters, and pool pumps based on dynamic pricing rates. This automated price-responsive program enables Tampa Electric Company to offer four pricing rates for electricity (low, medium, high, and critical) that provide lower rates approximately 87 percent of the time. The critical peak rate can be executed by the energy provider within minutes, and since 2008 they have reliably shed 3.1 kW during winter peak and 2.0 kW during summer peak per customer.

Conclusion

Gulf Power and Tampa Electric Company stand out as two early adopters that have improved customer satisfaction by implementing dynamic pricing programs that lower peak demand and enable customers to save money on their electricity bills. And these programs demonstrate that when implemented appropriately and with automation, they lead to sustainable behavioral changes in energy consumption that result in meaningful and sustainable load drop. Dynamic pricing is critical to the success of the smart grid as it aligns the cost of generating electricity with what users end up paying. While dynamic pricing programs can take many forms, and require proven technology and best practices to implement, utilities need to include them as part of their overall energy efficiency mix to improve the way in which energy is delivered and consumed across the globe.

ABOUT THE AUTHOR

Jason Cigarran is the Vice President, Marketing for Comverge. Prior to joining Comverge, Jason was the Vice President, Investor Relations for Eclipsys Corporation, a healthcare information technology company.

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