www.electricenergyonline.com

Electric Energy T&D MAGAZINE

MARCH-APRIL 2015 Issue 2 • Volume 19

THE CHANGING FACE OF ASSET MANAGEMENT

Electric Energy T&D
MAGAZINE

Publisher:
Steven Desrochers:
steven@electricenergyonline.com

Editor in Chief:
Terry Wildman:
terry@electricenergyonline.com

Account Executive:
Eva Nemeth: eva@electricenergyonline.com

Art Designer:
Anick Langlois: alanglois@jaguar-media.com

Internet Programmers:
Johanne Labonte: jlabonte@jaguar-media.com
Sebastien Knap: sknap@jaguar-media.com
Tarah McCormick: tarah@jaguar-media.com

Electric Energy Magazine is published 6 times a year by: Jaguar Media Inc.
834 Montée Masson
Terrebonne, QC Canada J6W 2C6
Tel.: 888.332.3749 • Fax: 888.243.4562
E-mail: jaguar@jaguar-media.com
Web: www.electricenergyonline.com

Electric Energy T&D Magazine Serves the fields of electric utilities, investor owned, rural and other electric cooperatives, municipal electric utilities, independent power producers, electric contractors, wholesalers and distributors of electric utility equipment, manufacturers, major power consuming industries, consulting engineers, state and federal regulatory agencies and commissions, industry associations, communication companies, oil & gas companies, universities and libraries.
Post Publication mail agreement #40010982
Account #1899244

Cover photo: Rodger Smith's
Credit: Oracle Utilities

Electric Energy T&D is proud to be a member of these associations


TRINITY
MEYER
UTILITY STRUCTURES
Pioneers. Experts. Innovators.
Trinity Meyer Utility Structures is a pioneer in the transmission industry.
We were the first to use steel for tubular transmission poles, the first to use corrosion-resistant weathering steel, the first to utilize full-scale vertical testing, and the first to develop wood-equivalent steel poles.
Our team of highly experienced in-house engineers have helped author many of today's industry standards and specifications. Engineered solutions for voltages up to 765kV are designed with our proprietary software and validated through years of comprehensive full-scale structural testing.
Innovations, such as our patented QuickPin Arm Connection and QuickPier Adapter, reduce total installation time and cost, and promote our commitment to reduce the environmental impact of your transmission lines.
We are the pioneers, experts, and innovators of steel tubular transmission solutions and your best choice for your transmission structure needs.
Trinity Meyer Utility Structures
For more information, please contact your local Trinity Meyer sales representative
877.282.MEYER
www.TrinityMeyer.com
ISO 9001: 2008

POWERPOINTS

Smart and Me

A few weeks ago, I attended the DistribuTECH Conference in San Diego. Every year the show is an eye-opener because every year the level of innovation and intellect on that floor gets greater for me. There's a subtle shift from Big Data to the Internet of Things and everything points to a smarter, more resilient grid. Attention to climate change is growing as evidenced in the drive to harden and brace against larger and more severe weather events, use big data more effectively and restore power as quickly and efficiently as possible.

As mind-bending and fascinating as the show was from corner to show corner, I remained on a mission – to have someone explain to me why smart meters should be vital and what having one means to me and any other householder on this planet. My quest made me feel somewhat like Joe Miller (Denzel Washington) in the movie *Philadelphia* when he iterated, "Now, explain it to me like I'm a four-year-old."

My Dad was in his early nineties when his house was selected as part of a group to have the first smart meters installed in Toronto. When he was canvassed by the hydro folks, he just seemed to glaze over, nod his head, and didn't ask a single question. To add insult to injury, the two people at the door didn't provide him with the hint of an explanation. To him, he didn't have any issues and life would continue as normal provided his lights, TV, and stove worked. It never occurred to him that the spinning dial was rapidly becoming a thing of the past and the world of electricity distribution was changing forever. And then my sister called and asked me to explain how the smart meter works and I had to admit that I was at a loss. The only advice I could give was to not let their pool heat pump run for undue time because the utility was 'watching' and was capable of shutting it down.

The concept of 'smart' is creeping into every corner of our lives. Few are exempt no matter where or how they live. Are we better off for having smart phones, PCs, tablets, mp3 players, TVs, robotic devices, medical procedures, energy-rich smart buildings and vehicles? Probably. Even if we aren't the stuff is here to stay and we are to evolve with it. Remember that 'smart' and 'intelligent' are relative terms.

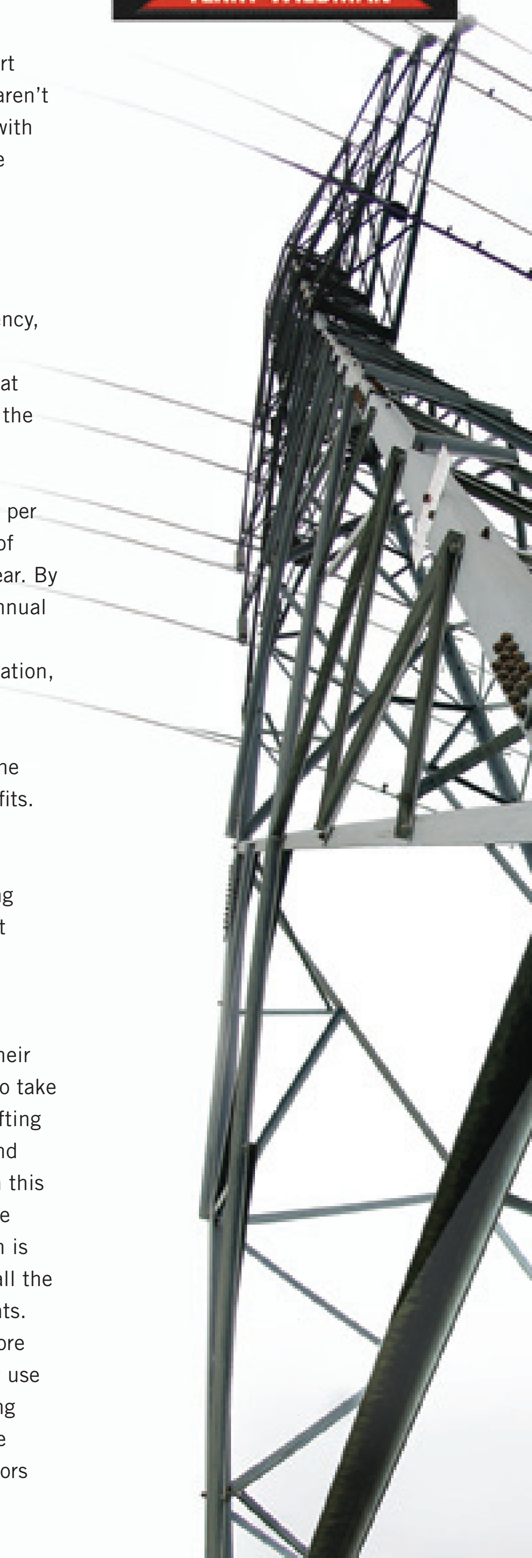
So, let's talk smart meters.

According to the U.S. Energy Information Agency, a smart meter refers to a device that updates energy consumption at least once an hour. That information is sent to both the consumer and the utility at least once each day.

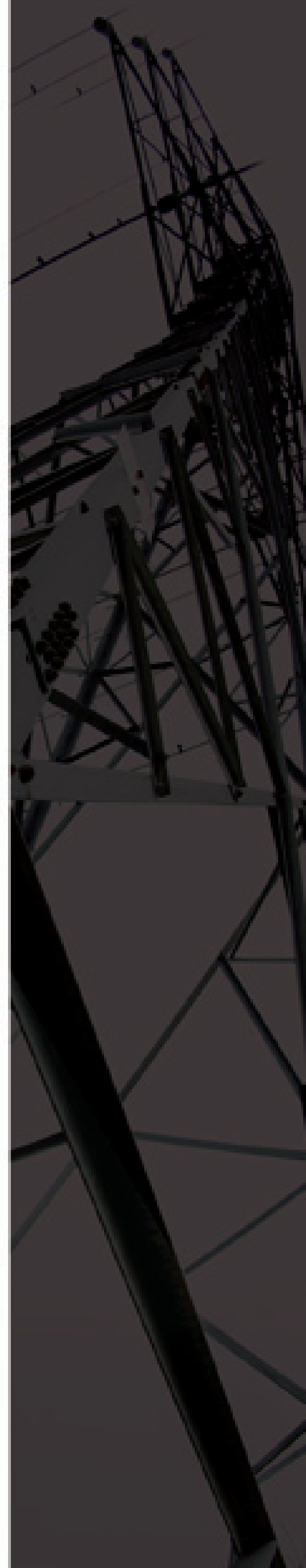
The technology is fairly new but smart meters per se are by no means unusual and the number of installed units continues to climb year over year. By enabling utility customers to estimate their annual bill smart meters can help users assess their individual energy habits, set goals for conservation, and easily monitor their progress.

When the new meters were first announced, the media had a field day downplaying their benefits. Statements like, "Smart meters are great and can tell you how much energy you can save – particularly if you do your baking or vacuuming at three in the morning," surfaced regularly. It certainly didn't help.

The key advantage, however, of the hourly breakdown is to enable utilities to fine-tune their peak rate charges, and to enable consumers to take more advantage of lower off-peak rates by shifting their energy usage to those hours whenever and as much as possible. Ideally, by interacting in this way, utility customers and utilities will both be focused on a common bottom-line goal, which is to avoid brownouts and blackouts, and forestall the need to build expensive additional power plants. What could be more satisfying than having more control over your lifestyle by managing energy use and making informed decisions about investing in energy conservation upgrades such as low-e windows, draught exclusion, and installing doors and insulation with higher R value ratings.



POWER POINTS



For many residential customers, peak demand changes can be eased without having to make any upfront investments in energy efficiency. One obvious example is to run non-essential appliances like dishwashers and laundry dryers during off-peak times. Today, many appliances can also be programmed to work on either side of peak hours and this advantage is becoming more popular. In addition, the potential for wireless communication between smart meters, appliances, and consumers enables the user to make the most of mobile energy management apps to tweak their hardware when away from their premises. Depending on the potential for mobile interaction, smart meters could also enable customers to help forestall brownouts more effectively by turning appliances down or off even when the user is not at home. That's on top of taking common-sense energy conservation steps like turning off lights when not in use, replacing older light bulbs with energy-saving 'curly' compact florescent bulbs or LEDs, and replacing broken or worn-out appliances with much more efficient models.

These connections between users and utilities will only grow as technology continues to ramp up and energy providers see, evolve, and/or establish new trends.

For some businesses, the need for lighting, equipment, and customer comfort are all considerations that can weigh heavily against basic conservation strategies during peak times. This is where things start to get really interesting. To get to the next level, businesses have to start thinking about investing in energy conservation. That means new equipment as well as building improvements such as weatherization, water conserving fixtures, and more efficient HVAC systems.

Up until now, businesses could calculate the return on their investment simply by projecting utility rates into the future. That could provide a sufficient incentive for upgrades in some cases, but not necessarily in others. The emergence of alternative energy and electric vehicles has provided businesses with a much stronger bottom-line incentive, and that's where the interplay between smart meters and a smart national grid comes in.

In many areas, the grid is transitioning from a reliance on massive, centralized power plants to a distributed model in which small, medium, and large renewable energy resources play an increasingly dominant role. Given that much of the renewable input is currently from intermittent sources – wind and solar – energy storage is a critical component. The end result is that utility companies must be much lighter on their feet, with the added complication that many of the utility's customers are now, or have the potential to be, its energy suppliers as well as being its storage reservoirs. Managing such a complex, information and data centric system through conventional meters, with their lack of interactivity and monthly readings, would simply be impossible

In terms of the utility customer as an energy supplier, that trend is already firmly established by the rapidly growing number of grid-connected solar installations on rooftops and other relatively small sites. The latest thing is the use of electric vehicles (EVs) as mini-distributed energy storage hubs. The basic idea is that utility customers can charge up their EVs during off-peak times, and then use the stored energy in the EV batteries to power elements in their homes and business. That relieves pressure on the central grid while enabling EV owners to cut peak out-of-pocket hour rates. Some enterprising EV owners are offering to use their fully charged batteries to top-up EV owners who have depleted batteries.

It's worth noting that EV manufacturers are aggressively pushing the EV phenomena by packaging an EV purchase with a free or discounted charging station. Some packages also include rooftop solar panel setups to help offset charging costs.

Then there are the secondary benefits of the smart meter/smart grid for business apps. The cost of energy has long impacted the bottom line. In recent years, two overlapping factors have come together to make energy use a top-of-mind concern.

1. The urgency of addressing climate change, which in so many ways depends on using energy more efficiently while transitioning to more sustainable resources.
2. Consumers are becoming aware of the public health benefits of conservation and clean energy and that themselves are increasingly attracted to businesses that share their concerns.

This gives an edge to businesses that install renewable energy hardware on site. They can only benefit from increased traffic to their door.

I'm pretty sure I'm now on the road to understanding the complexities of *smart*. I think I like it.

TVA Employees Recognized For Tech Contributions

March 2015

Several Tennessee Valley Authority engineers and researchers have been named by the Electric Power Research Institute as 2014 Technology Transfer Award recipients.

"These awards fit with our mission of service," said Joe Hoagland, vice president for TVA Stakeholder Relations. "At TVA, we continue to look at innovative ways to improve our operations, and these awards are about championing important technologies that solve critical industry issues.

"These employees are commended for driving progress and providing benefits not only to TVA, but to the whole industry."

EPRI, with offices in several U.S. locations including Knoxville, is an independent, nonprofit organization that conducts research, development and demonstration projects relating to the generation, delivery and use of electricity for the benefit of the public. For more information, see www.epri.com.

These awards are given annually to EPRI members who have led technology transfer efforts on behalf of their companies and the industry at large.

This year's TVA winners are:

Ed Stephens and Karen Utt were recognized for their energy-economy modeling and development of the United States Regional Economy, Greenhouse Gas and Energy Model (US-REGEN) - an analytical model used to evaluate and provide insights on the possible impacts of proposed environmental regulations, potential future climate/clean energy legislation, potential expansion of renewable energy, and load growth on the United States electric power sector.

Fred Carder was recognized for a case study on the systematic approach to lower-load operation. He led a multi-phase EPRI case study at TVA's Cumberland Fossil Plant Unit 1. The results of the case study, which monitored performance of the boiler, turbine, selective catalytic reduction (SCR) systems and water chemistry, will allow TVA to increase the turndown (lower-load operation) potential of its plants while maintaining compliance with their environmental operating permits.

Mark Bowman, Richard Brehm, Robert L. Davis, David Murray and Benny Westmoreland were recognized for collaborating with EPRI in the development and field testing of a technology for detecting open-phase conditions in large transformers, which can result in equipment damage if not identified and addressed. TVA hosted a successful demonstration of the technology at Bellefonte Nuclear Plant site. TVA intentionally open-circuited a high-voltage transmission line (161 kilovolt) and, as predicted, the system detected the open-phase condition. Several nuclear plants are planning to install the new technology at their plants.

Stephen Mueller was recognized for his work partnering with the Southeast Atmosphere Study Air Quality Campaign. As a result of his leadership, this work will improve the knowledge of the drivers and impacts of air quality, thus providing important benefits to both emissions research and the public at large.

Other EPRI recognition

Keith Taylor, TVA nuclear's senior program manager of Alliance Turbine Services and Maintenance & Modifications, was also recognized for serving as the utility chairman of EPRI's Generation Sector Turbine Generator User's Group (TGUG) since January 2013. The TGUG meets twice a year to discuss and resolve common concerns affecting the safety, equipment reliability, outage improvement and power production in relation to turbine generators, associated systems and sub-components.

Taylor served as the secretary of TGUG prior to being elected by his peers to serve as chair. Beginning in February 2015, he will serve as TVA's program advisor to EPRI's Steam Turbines-Generators and Auxiliary Systems Research Program.

Electric Cooperatives Oppose Proposed Lowering of Ozone National Ambient Air Quality Standard

March 2015

The National Rural Electric Cooperative Association (NRECA) joined a broad coalition of industry stakeholders in requesting that the Environmental Protection Agency (EPA) retain the current ozone National Ambient Air Quality Standard (NAAQS) at 75 parts per billion (ppb). On behalf of America's member-owned, not-for-profit electric cooperatives, NRECA CEO Jo Ann Emerson voiced concerns about the agency's proposal to reduce the level of allowable ozone to between 65 and 70 ppb.

"America's electric cooperatives across the country are already working to meet the current 75 ppb ozone limit, established in 2008. Yet even before this standard has been met, EPA proposes lowering it yet again. More troubling still, the agency has not provided sufficient evidence to prove a public health benefit for sensitive populations. Most studies show no discernible public health benefits under the proposed standard. In many rural areas - particularly in the western part of the country - the lower ozone concentration ranges considered in EPA's proposal would require reductions in ozone to below naturally occurring levels. In other words, utilities and manufacturers would have to improve upon Nature and rid the air of naturally-occurring ozone from vegetation and wildfires or ozone transported across international borders. Electric cooperatives support standards backed up by scientific research - this proposed standard does not meet the bar."

INDUSTRY NEWS

FirstEnergy Earns Industry Awards for Emergency Recovery and Providing Mutual Assistance Crews to Neighboring Utility

March 2015

FirstEnergy Corp. (NYSE: FE) has again earned recognition from the Edison Electric Institute (EEI) for its restoration efforts in 2014 in Pennsylvania and Maryland following a severe winter ice storm and for providing assistance to DTE Energy in Michigan following a major summer thunderstorm.

EEI presents these awards annually to member companies to recognize extraordinary efforts to restore power or for assisting another utility company after service disruptions caused by severe weather conditions and other natural events. Winners are chosen by a panel of judges following an international nomination process, and the awards were presented during EEI's spring CEO and Board of Directors meeting in Washington, D.C.

"FirstEnergy's recovery efforts exemplify the industry's commitment to serving its customers even in difficult weather conditions," said EEI President Tom Kuhn. "Moreover, FirstEnergy's support to DTE Energy is a great example of the spirit of mutual assistance and the willingness to help neighboring utility companies."

"Receiving these EEI awards is especially gratifying because we believe our storm restoration process is one of the best in the industry," said Steven Strah, senior vice president of FirstEnergy and president of FirstEnergy Utilities. "On behalf of the FirstEnergy employees who devoted the extra hours to safely make repairs for their own customers and also for DTE Energy customers, the company is honored to accept these prestigious awards."

FirstEnergy earned the "Emergency Recovery Award" for restoration efforts following a snow and ice storm in southeastern Pennsylvania and Maryland in February of 2014. Heavy ice and snow brought down trees and wires across FirstEnergy's Metropolitan Edison Company and Potomac Edison Company service areas, leaving more than 226,000 customers without power. The restoration effort was complicated by treacherous driving conditions which made some areas with outages tough to access. Despite the difficult conditions, FirstEnergy assembled a team of more than 3,000 line workers and support personnel and was able to restore all affected customers within five days.

The "Emergency Assistance Award" recognized FirstEnergy's efforts to assist DTE Energy to restore service following a major thunderstorm in southeastern Michigan in July of 2014. Intense rain, hail, wind and lightning caused severe damage to DTE's infrastructure, leaving more than 200,000 customers without service. When asked to provide mutual assistance, FirstEnergy sent 172 workers and 83 trucks to assist with the restoration process, which resulted in all DTE Energy customers being restored to service in less than a week.

Southern Company CEO receives national award for leading nuclear development with Vogtle construction

March 2015

MARonal Labor and Management Public Affairs Committee (LAMPAC) has named Southern Company Chairman, President and CEO Thomas A. Fanning as a recipient of the 2015 John D. Dingell Award. Fanning and North America's Building Trades Unions President Sean F. McGarvey will be presented the award at a reception in Washington, D.C. this evening. Fanning and McGarvey were recognized for their shared commitment to new nuclear development and partnership in building two of the nation's first nuclear units in more than 30 years at Southern Company subsidiary Georgia Power's Plant Vogtle.

Named for the longest-serving member of Congress, the John D. Dingell Award is presented to leaders whose efforts have helped to advance the common objectives of the electric power industry and International Brotherhood of Electrical Workers (IBEW) members. Mr. Dingell served as Chairman of the House Energy and Commerce Committee for many years, where he amassed an impressive record of accomplishments on a wide range of issues, many of which focused on labor management collaboration.

"Leading the way in new nuclear development requires a shared focus on safety and quality as the highest priorities," said Fanning. "This award is a tribute to the thousands of men and women dedicated to ensuring nuclear remains a dominant solution for America's energy future through the construction of Vogtle units 3 and 4."

Under Fanning's leadership, the Southern Company system has committed $20 billion to developing the full portfolio of energy resources - nuclear, 21st century coal, natural gas, renewables and energy efficiency. As part of this commitment, Georgia Power's Plant Vogtle units 3 and 4 are designed to generate enough combined electricity to power 500,000 homes and businesses. The Vogtle project is the largest job-producing project in Georgia, currently employing more than 5,500 construction workers onsite, and will result in 800 permanent jobs when the plant begins operating.

Subsidiary Southern Nuclear is overseeing the construction and will operate the units for Georgia Power and co-owners Oglethorpe Power Corporation, the Municipal Electric Authority of Georgia and Dalton Utilities. Southern Nuclear currently operates Plant Vogtle's two existing nuclear power units, as well as Georgia Power's Plant Hatch and subsidiary Alabama Power's Plant Farley. These facilities provide 20 percent of the electricity used in Alabama and Georgia.

Fanning's nuclear leadership extends beyond Southern Company. He is a member of the Institute of Nuclear Power Operations board of directors and the World Association of Nuclear Operators - Atlanta Centre governing board. In addition, Fanning serves as chairman of the Electricity Subsector Coordinating Council, vice chairman of the Edison Electric Institute (EEI), a member of the international advisory board of the Atlantic Council and chair of the board of directors of the Federal Reserve Bank of Atlanta.

National LAMPAC - a joint effort of EEI and IBEW - is a labor and management public affairs committee created in 2008 to advance the common objectives of the electric power industry and IBEW members. Through National LAMPAC, labor leaders and electric utility executives advance the common goals of a well-managed, efficient business, with a ready supply of qualified, skilled workers and the hope of greater prosperity and growth.

THE GRID TRANSFORMATION FORUM

Envisioning the 21st Century Grid

The Changing Face of Asset Management

As both utility workforces and infrastructure continue to age, asset management takes on an increasingly vital role. We asked Rodger Smith, senior vice president and general manager of Oracle Utilities Global Business Unit, to share his views on the changing face of utility asset management, and the drivers for these changes.

EET&D: The International Energy Agency (IEA) has indicated in its World Energy Investment Outlook 2014 that $740 billion annual power infrastructure investment is needed globally over the next 20 years, with 42 percent of that going to building and refurbishing transmission and distribution networks. What role does the optimization of existing utility assets play in this projected, massive investment?

Smith: Many of the utility assets in operation today were installed in the growth boom of the 1960s to 1970s and have reached the end of their useful life. Aging infrastructure is creating a growing risk for utilities that asset replacement budgets can't keep up with. Asset optimization is increasingly mission-critical for utilities. However, many utilities are not yet prepared to realize the business value asset optimization provides. As PriceWaterhouseCoopers' 13th Annual Global Power & Utilities Survey noted, utilities share the view that asset performance improvement is necessary, topping the list of areas for improvement with 73 percent of those utility executives surveyed. Interestingly enough, 60 percent also see improvement needed in asset risk management.

EET&D: Where are the most critical areas for improvement in asset management, in your opinion?

Smith: One of the biggest areas in which improvement is vital is using asset analytics to drive reliability-centered maintenance programs. Here's why: Historically, utilities have relied upon traditional asset maintenance processes and a run-to-failure approach to many assets. As utility infrastructure and assets continue to age, the utility workforce is also aging and retiring. At the same time, the utility's budget with which to maintain or replace those assets has continued to decrease. Retaining a manual, reactive approach to asset management, in the face of these challenges, increases the risk to asset reliability and operational efficiency, and typically leads to higher costs to the utility, as device failures occur that could have been prevented given more timely maintenance. We have all seen examples of catastrophic failures of critical utility assets make the front page news headlines and lead to regulatory inquiries and political scrutiny of utility processes.

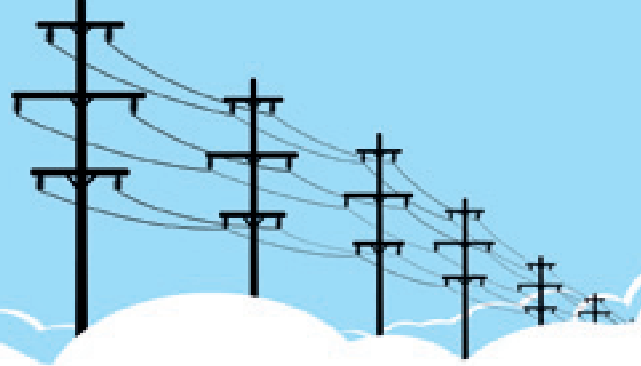
EET&D: So how can technology enable utilities to avoid such risk?

Smith: Historically, data has resided in utility department silos. In order to be able to look at assets and asset maintenance in a holistic way, better centralization, visibility, sharing and analysis of asset data across the enterprise is needed. This is particularly useful for investment and risk planning with regard to asset replacement. Let me elaborate: Asset management and maintenance have always been a balancing act between efficiency (i.e., the cost of providing the equipment) and effectiveness (i.e., the availability and efficiency of the equipment). Each utility approaches that balancing act differently, but the essence of most utility maintenance strategies is to optimize the availability of the assets against the cost constraints of providing that availability. Therefore, the more robust the enterprise data is on those assets, the better the decisions on best actions for particular assets can be.

EET&D: You mentioned asset management as a balancing act between efficiency and effectiveness. What do you see as the fulcrum in that balance?

THE GRID TRANSFORMATION FORUM

Envisioning the 21st Century Grid



Smith: Again, every utility approaches that balancing act differently. But both automation and analytics can play important roles in the balancing act between efficiency and effectiveness. I mentioned earlier that manual, reactive processes can increase the risk to asset reliability. In a more proactive approach, taking action on the right asset at the right point in time – or 'right work/right time' management – is made much easier. By using analytics to identify prevailing trends in usage and asset health, utilities can better balance the availability of assets against the cost of providing that availability. For instance, utilities can leverage detailed usage and weather data to assist in identifying overloaded transformers.

As well, this type of actionable information can be used to better prepare field employees for specific repair/replacement situations. Every year, utilities are faced with difficult budget cuts to capital and maintenance programs in order to maintain corporate financial targets. With asset risk management and asset investment planning techniques, utilities can know exactly what the risks of such cuts in order best manage and minimize their impact.

EET&D: So asset risk management becomes a focus on asset optimization, rather than run-to-failure and replace?

Smith: Yes, precisely. Proactive work reduces asset failure rates and drives down the cost to operate each asset. For example, costs are reduced and reliability is improved by scheduling proactive work during normal business hours instead of being a reactive after-hours call-out due to a failure. If you add automation to this equation, possible now with smart sensor and control devices all along the utility's infrastructure, real-time asset analysis also becomes part of the asset management toolset. Advanced asset risk analytics can correlate the appropriate data from across the enterprise (specific sensor data with advanced metering data, for example) to provide immediate prescriptive maintenance work requests, effectively mitigating a problem while it is still minor. Use of smart sensors and related real-time communications is growing at an exponential rate as costs decrease with the evolution of the technology. Many of these smart devices come IP addressable and wireless connected, creating an Internet of Things (IoT) that a number other industries have been using for years to drive operational performance. Utilities are just starting to leverage the sensor technologies.

SmartGrid CANADA

2015 OCT 5-7

Smart Grid RoadShow

CONFERENCE CONFÉRENCE

Hilton Markham Suites, Markham, Ontario Canada

www.smartgridroadshow.com

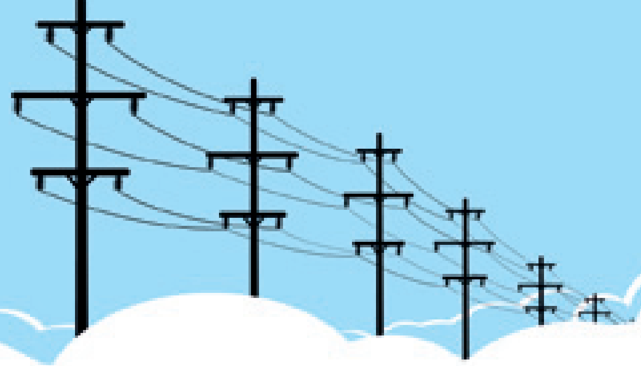
The Premiere Smart Grid Event in Canada returns October 5-7 2015 to Toronto.

HOST UTILITY

Power Stream

PREMIERE SPONSOR

Schneider Electric



EET&D: But smart devices create an additional wrinkle to traditional asset management approaches, don't they?

Smith: Yes, in the sense that manual approaches to asset management have become even less effective. Smart devices do require new field maintenance processes like device configuration and firmware updates. However, automated device management processes (like the automated updates on your smart phone apps) can reduce the need to put more people in the field to accomplish this new work. Much like the physical assets, smart devices must be managed across their lifecycles to avoid failures. Say one of your device vendors notifies you of a critical security patch to the device firmware. Is there a process to get this update tested, installed, and documented to support a regulatory audit? Operational device management does that and can serve as a utility's automated lifecycle management and maintenance shop, analyzing data in real time to swiftly identify and proactively adjust, update and repair security, performance and compatibility issues as they arise.

EET&D: You mentioned earlier the issue of an aging utility workforce. Is there a way to capture this field and equipment knowledge before it is lost? What about best practices?

Smith: Absolutely. Our teenage kids and new hires are showing us how cool technology like GoPro cameras and Google Glasses can be used to capture and display information. In the utility we are finding these can be great transition technologies for knowledge capture of the aging workforce and to equip the new hire digital natives to leverage their experience. For example, a senior crew member can video capture complex maintenance procedures from a camera mounted on his hardhat. Mobile workforce and asset management technologies can store these procedures and play them back for the new hires to assist them as they do their work. Other things such as internal social media interaction with peers as they do their work can help less experienced crew members with questions or issues that might arise.

EET&D: Utilities aren't known to be early adopters of new technology. Are they ready for all this?

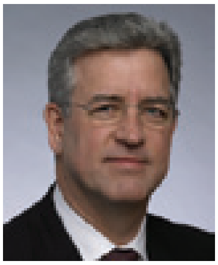
Smith: Not all of them. But many are realizing we can't keep doing this the same way we always have. Customers are demanding more while sustainability and efficiency are reducing utility revenues, putting additional pressures on asset maintenance and replacement budgets. It is going to take real leadership across the industry to make this happen. It's going to take leadership that is willing to embrace new ways of doing things and new technologies to drive performance like we have never seen it before.

EET&D: What is holding us back?

Smith: Lack of imagination and fear of failure. Listen, I get it that we are in a high-risk industry and people lose their jobs when things don't go right. Innovation starts with leadership. It's easy to sit back and keep doing it the way we always have. If we aren't driving innovation, we are going to fall behind, even in the utility industry, and that's when customers and regulators start to make things difficult. I like what Thomas Edison said: "Our greatest weakness is giving up, the most certain way to success is to try one more time."

EET&D: We can't thank you enough Rodger for taking the time out of a hectic schedule to share your insight and considerable knowledge about driving change in the world of asset management with our readers.

About the author



Rodger Smith is senior vice president and general manager of Oracle Utilities Global Business Unit. His passion for the opportunities afforded to today's utilities by changing customer expectations and new technologies is fuelled by extensive hands-on utility experience at Southern Company, combined with utilities consulting experience in positions with PriceWaterhouseCoopers and Black & Veatch before joining Oracle.

GREEN OVATIONS

Innovations in Green Technologies

Incentives are Turning End-users into Partners in the Quest for Reliability

By Cara Olmsted

In an earlier era, responsibility for maintaining the reliability of America's power systems rested chiefly in the hands of public utilities and electric power grid systems.

But that has begun to shift in important ways.

Today, we increasingly see public utilities, power grids and individual state energy offices recruiting energy end-users to serve as their partners in maintaining reliability.

End-users are being incentivized to implement strategies that will manage peak demand, elevate responsiveness, and promote resiliency in their buildings. The goal is to help ensure the reliable availability of electrical power, especially at times of peak demand.

Some of these incentives can be lucrative and can dramatically reduce payback periods for the end-user's energy-related capital improvements.

The two key strategies now used to help incentivize a more-efficient use of energy are 'Demand Response' and 'Demand Management' programs.

Demand Response and Demand Management Programs

The federal government defines Demand Response (DR) as a change in 'electric usage by end-use customers from their normal consumption patterns.' DR can include 'incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.'

DR incentives are now offered by at least six regional grids: the New York State Independent System Operator (NYISO), the California ISO (CAISO), the Electric Reliability Council of Texas (ERCOT), ISO New England, the Midcontinent Independent System Operator (MISO), PJM Interconnection, and the Southwest Power Pool.

According to a December 2014 Federal Energy Regulatory Commission staff report titled Assessment of Demand Response and Advanced Metering, potential peak reductions from DR programs reached 28,798 MW in 2013, a 9.3 percent increase over 2012 levels.

While DR programs focus on voluntary reductions in usage in response to particular events, they are complemented by inducements to end-users to make energy efficiency investments in the form of Demand Management Program (DMP) incentives. DMP incentives are generally available across the country and vary by utility, municipality and state.

When used in conjunction with one another, Demand Response and Demand Management supplement each other. They generate new revenue streams and provide incentives for an array of energy-efficient equipment and retrofits, thus increasing performance, comfort, and resiliency, while bolstering a building owner's bottom line.

New York City as a geographic case study

Among all the regions nationwide, energy users in New York City have one of the most-lucrative and broad DR and DMP incentives available at this time.

Part of the reason for the area's focus on reliability arises from the potential closure of the Indian Point Nuclear Power Plant in Westchester County, New York by as early as mid-2016, which, in turn, could result in an energy supply shortfall of 1,450 MW across the state.

Of that total shortfall, 100 MW of peak demand has been targeted for reduction through demand management, a strategy through which a wide array of property owners and operators would be able to reduce energy usage in their buildings at strategically significant times.

To achieve this goal by 2016, Consolidated Edison Company of New York (commonly called Con Edison or ConEd) and the New York State Energy Research and Development Authority (NYSERDA) have collaborated to increase the incentive value of DR and DMP programs for eligible customers.

The combination of offerings gives building owners unique opportunities to reduce energy demand, generate savings, and reduce their carbon footprint, all while helping the regional grid and the local utility maintain the power infrastructure the area depends upon.

The potential benefits of DR and DMP

To demonstrate the extent of the incentives involved in New York City, our team created a hypothetical case study in the form of a two-building commercial office complex in New York City.

Its owners have decided to tap the full spectrum of DR and DMP incentives as a way to reduce energy expenses, generate new revenue streams, and replace aging equipment.

Remarkably, our calculations found that the complex stood to earn back the full cost of its investment within two years and nine months. After that point, all energy savings would directly lower bottom-line operating costs for an indefinite period going forward.

Moreover, on an ongoing basis, the buildings would enjoy the benefits of various battery, lighting, back-up generation, and other valuable energy-management resources they previously lacked.

In other words, after the payback point has been reached, all of the savings these improvements generate represent 100 percent pure and unencumbered revenue - as well as an improved building.

Energy analysts would agree: a payback period of this length is considered short relative to the upgrades being performed and the significant investment made.

In New York City, the DMP initiative is jointly administered by Con Edison and NYSERDA, while the DR incentives are provided through Con Edison and NYISO.

DMP incentives available to the New York City complex

Available DMP incentives span an array of energy-saving technologies, including thermal and battery storage, HVAC, lighting, controls, and DR-enabling equipment.

Here is a brief description of options available for facilities in New York City (and Westchester County) for building upgrade investments, including battery storage, lighting, building management, and backup generation. Each project would contribute to reduced energy demand or provide standby power – and most provide load flexibility to meet pledged load reductions during DR events, and create resiliency to respond to unplanned distribution outages and/or severe weather conditions.

Battery Storage: A typical size for this installation would be a 450 kW, 1.8 MWh advanced lead acid battery storage system. With this system, the site owner will be able to take advantage of the enhanced DMP incentive for battery storage, which totals $2,100/kW, capped at 50 percent of the total cost. A $1.8 million battery storage system would qualify for an incentive of $630,000, resulting in an upfront cost of $1.17 million.

Using the battery for demand charge savings would yield annual energy bill savings of approximately $122,664. In addition, 125 kW of the battery's capacity would be used for demand response, which would yield approximately $39,125 annually in incentive payments. Total annual benefit realized from the battery would be approximately $161,789.

Lighting: With a substantial, common area space devoted to hallways and stairwells, lighting provides a unique opportunity to reduce year-round energy consumption throughout the site.

Replacing existing T12 fluorescent tubes and magnetic ballasts with reduced wattage high-performance T5 tubes and dimmable electric ballasts, the site lighting load will be reduced by 30 percent. DMP incentives provide a 50 percent discount off the installed cost, reducing the expense from $750,000 to $375,000.

Energy Management System: Incorporating an energy management system with any of the upgrades will help curtail energy usage during DR events by enabling a further reduction in lighting demand. Under current DR incentives, the total awarded amount is $40,000 off the $100,000 installation cost. Combined with the new energy-efficient lighting fixtures, the energy management system will help the site owner save more than $300,000 annually on its electric bill.

Backup Generation: In the aftermath of Superstorm Sandy in 2012, building owners and operators across the region have been focusing on ensuring the performance of their critical systems during service disruptions. Site owners can tap DR enablement incentives to help defray the cost of a generator system to provide both DR benefits and backup power during an outage. An owner would be eligible for an $800/kW DR enablement incentive, capped at 75 percent of project cost. This would reduce a 225 kW system's $350,000 price to $170,000.

Project Bonus: As an additional incentive, the DMP program includes a 10 percent bonus for reductions of over 500 kW, and a 15 percent bonus for projects greater than 1 MW. Under this case study scenario, the project is eligible for an additional 10 percent of the awarded incentive amount, in this case $118,833.

DR incentives

The DMP-funded improvements not only help reduce building-specific energy demand and system-wide load. They also can help generate additional revenues by enabling participation in multiple DR programs from both Con Edison and NYISO. A description of the DR programs follows:

NYISO Special Case Resources (SCR): This program qualifies the site for the DR enablement incentive under DMP. Participants pledge curtailment levels based on summer and winter seasonal demand and receive monthly capacity payments averaging approximately $18/kW/month during the summer capability period, and approximately $8/kW/month during the winter capability period. Owners with SCR-enrolled resources also receive a performance payment of $0.50/kWh for energy reduction during called DR events.

With a total pledged load reduction of 400 kW, the site will generate approximately $43,200 through SCR during the summer period, $19,000 during the winter period, and could generate an energy performance payment of approximately $3,200, assuming four events are called in a year.

Con Edison Commercial Service Relief Program (CSRP): CSRP is Con Edison's day-ahead, 21-hour notification program. CSRP pays customers $10kW during May through September. CSRP also offers an additional $1.00/kWh for energy curtailed during called events. The hypothetical property's management will be able to pledge 400 kW, which can yield a $20,000 capacity payment and an estimated $4,800 performance payment.

Customers are also incentivized to stay enrolled in the program(s) for three years. The added incentive means that the site can generate a bonus payment of between $48,000 and $60,000 in the third year of the program.

Con Edison Distributed Load Relief Program (DLRP): DLRP, the 2-hour advance notification program, is structured similarly to CSRP. But its payment rates depend on the particular local network in which the customer is located.

Customers located in networks requiring greater flexibility to respond to unforeseen system impacts, receive $15/kW/month, with a performance payment of $1.00/kWh for energy reduced during events. This hypothetical site is situated in such a network, making its 400 kW pledge worth $30,000 per season. By taking advantage of all aspects of DLRP, the site stands to receive revenues of approximately $4,800 per season in energy performance payments and a three-year Retention Bonus of between $24,000 and $30,000.

The chart below spells out the potential benefits that are available through participation in the full scope of DR and DMP incentives:

APPROXIMATE COSTS, DEMAND MANAGEMENT PROGRAM INCENTIVES & DR REVENUES REALIZED AT A NEW YORK CITY COMMERCIAL OFFICE COMPLEX

Project	Costs ($)	Demand Management Installation Incentives ($)	Costs After Incentives ($)	Estimated Total Demand Response Revenue Year 1 ($)	Estimated Total Demand Response Revenue Year 2 ($)	Estimated Total Demand Response Revenue Year 3 ($)	Estimated Annual Utility Bill Savings ($)	Approximate Simple Payback Based on DMP Incentives, DR Revenues, and Utility bill savings
Battery Storage	1,800,000	630,000	1,170,000	39,125	39,125	67,250	122,664	7.23
Energy Efficient Lighting	750,000	375,000	375,000	n/a	n/a	n/a	251,141	1.49
Energy Management System (common area lighting controls)	100,000	40,000	60,000	15,650	15,650	26,900	115,020	0.46
Generator	350,000	180,000	170,000	70,425	70,425	121,050		2.41
10% Bonus for +500 kW		118,333						
TOTALS	**3,000,000**	**1,347,500**	**1,615,000**	**125,200**	**125,200**	**215,200**	**488,826**	**2.69**
Approximate Simple Payback Based on DMP Incentives, DR Revenue, and Energy Bill Savings: 2.69 Years. $1.6M / ($125K + $489K) = 2.69 Years								

Find the DMP and DR incentives available in your area – and act!

The case study shows that by optimizing DR and DMP incentives, building owners and operators have the opportunity to earn back their energy investment in a short period of time. These incentives and the revenue streams from demand response participation also allow customers to increase their overall efficiency, reduce operating and energy costs, and meet environmental and sustainability goals. Owners should work with their energy advisor to determine the specifics of the programs available in their area.

To access the incentives and maximize the value of the demand response payments, customers are encouraged to start the process now. Demand response summer participation varies by region; in New York, the period starts May 1 and DMP incentives are issued on a first-come-first-served basis.

Owners need to keep in mind that there is a ramp-up period for participation that may include budgetary, planning, and implementation considerations.

Work with a qualified ESCO

To take maximum advantage of DR and DMP incentives, end-users should tap the expertise of a qualified Energy Services Company (ESCO) that can help the owner understand all the DR and DMP incentives available in its area – and can incorporate a full scope of demand response capabilities in modifying load shape into a proper energy supply portfolio.

The most sophisticated ESCOs offer proprietary software and can help equip large energy consumers with sophisticated energy monitoring and control capabilities. Such resources enable users to control power grid responses, while providing state-of-the-art dashboards that equip customers to monitor system performance and compliance during grid events, as well as for routine operations.

The End-user is now the partner

Whether your area has DR and DMP incentives available now, or whether such programs may be implemented in the future, it makes sense to get started months in advance in order to reap full program benefits.

America has arrived at a new era in energy reliability, an era when the end-user is being called upon to play an active supporting role. The good news for end-users is that they have a chance to derive substantial benefits as they begin to take on the role of partners in the quest for long-term reliability.

About the Author

Cara Olmsted is Director of Marketing and Business Development with ConEdison Solutions in Valhalla, NY. She manages the residential and commercial commodity, behind-the-meter solar, and demand response lines of business with regard to product development, new market entry, and strategic and tactical marketing implementation. Ms. Olmsted holds an MBA in finance and marketing from Fordham University and a BS from the University of Missouri.
colmsted@conedsolutions.com

From Research to Action

The Future of the Smart Grid: Interoperability and Analytics

By Raiford L. Smith, CPS Energy; Matt Wakefield, EPRI; and Stuart Laval, Duke Energy

Much has been written about the role of distributed energy resources (DER),[1] smart meters and other grid connected devices, but the next revolution for the smart grid comes from the utilization of advanced analytics and interoperability. These analytics-based capabilities are enabled when information and telecommunications technology is fully integrated into the electric grid's DNA. This convergence between operational and information technology has already begun – several key companies are working towards developing these capabilities.[2] However, there are three critical barriers that impede our ability to achieve these outcomes, including:

1) Incorporating a common language required by many applications in order the connect.
2) Making data secure and available to enable analytics whenever and wherever necessary
3) Optimizing centrally-managed systems with distributed problem-solving so our grid can operate more resiliently, quickly, and efficiently.

Overcoming these hurdles should create a more open, secure, interoperable grid that can handle significantly more distributed energy resources and microgrids while improving reliability and reducing costs relative to today's existing technology.

Creating an Open Playing Field

Computer scientists refer to middleware as software that enables coordination, communication and data sharing among applications and between vendor products. Now data from different vendor applications may be unlocked using a common, standards-based solution such as a field message bus. Advances in open field message bus standards enables utilities to more easily link together DER, smart meters and other distribution automation assets and enable advanced analytical capabilities.

Making Data Securely Available

Today, many electric utility applications backhaul data generated by one set of vendors to a centralized point and push it through middleware from another vendor to 'unlock' the information for use by applications[3] from yet more vendors. Unfortunately, this process is both expensive and time-consuming. Additionally, this introduces a single point of failure (the centralized software) and permits vendor lock-in since technology can be proprietary until it reaches the middleware. By also placing distributed publish-subscribe middleware at the edge of the network, grid-based applications can enhance resiliency by eliminating the single point of failure. Placing middleware at the edge can also break down the barriers of proprietary technology by unlocking data from all vendors also at the edge of the network. Furthermore, this solution permits a more secure, resilient grid by allowing a utility to install new, distributed analytical tools throughout the network to manage and monitor the security and operational functions of the grid.

Enhancing and Augmenting Centralized Systems

Middleware is typically installed at the core of the network because this is where most of the decision-making software currently resides. As previously mentioned, such a design requires all data to be backhauled to a centralized point in order to make a decision. Yet, backhauling all data is an inherently slow, cumbersome, and an expensive process. To make matters more challenging, one of today's fastest growing technologies on the grid, DER, may not be able to rely on centralized systems due to their need for extremely quick decision-making. A fully centralized management system cannot provide the required performance at the desired cost because they are inherently slow. Implementing distributed or layered intelligence pushes certain decision-making functions to the edge of the network in order to improve response times and reduce costs. A hybrid of a centralized and distributed architecture can enable the performance and decision making capabilities needed by utilities, by unlocking data and systems at the edge of the network, and by allowing new DER and microgrid management tools to make rapid decisions in coordination with the utility's existing centralized management tools. A related and emerging approach is what is referred to as an 'Open Application Platform.'[4] The open application concept is easily explained through an analogy using a familiar device – the smart phone. Mobile devices were once limited in functionality by their firmware, as they were simply unable to run applications. By adding a framework and support for applications, smart phones are now thriving platforms for third-party development. Additions in functionality no longer require a firmware upgrade. Rather than being limited to a fixed set of capabilities for the life of the device, a smart phone user can tailor the product to their individual needs and update product functionality as those needs evolve. Third-parties can bring new capabilities without involving the manufacturer or updating the device firmware.

How CPS Energy is Leading the Charge

CPS Energy serves the greater San Antonio, TX, region and is one of the nation's largest municipally-owned, vertically-integrated electric and gas utilities. While CPS Energy is currently a leader in demand response[5] and renewables,[6] it is actively partnering with organizations such as the National Renewable Energy Laboratory (NREL), the Electric Power Research Institute (EPRI), and Duke Energy to test and deploy the next generation of smart grid interoperability and analytical capabilities. To deliver these benefits, CPS Energy will implement standards-based technologies in its 'Grid-of-the-Future' deployment area in San Antonio, demonstrating benefits for customers, interoperability, and new analytical capabilities.

Enabling Future Analytical Capabilities

As utilities and vendors embrace utilizing an open-source, standards-based, publish-subscribe middleware platform, new analytical functions can be developed to create micro-forecasts of supply and demand, to detect theft, to enhance the safety of the grid, to monitor vegetation, and to manage distributed intermittent resources. Today, these solutions are proprietary, slow, and costly. Yet, by adopting some readily-available technology, we can more easily implement additional DER's and microgrids at cost and performance targets that currently seem unachievable. Long ago, information technology evolved from centralized-systems (mainframe computers) to a distributed architecture (tablets and laptop computers as well as cloud-computing). Similarly, telecommunications adapted to this paradigm, shifting from land-line phones and centralized, analog switching to digital, distributed infrastructure and smart phones. Isn't it time the utility industry caught up?

Workshop to Explore End-to-End Interoperability and New Platform

CPS Energy, Duke Energy, EPRI and NREL are hosting an open industry workshop [7] on Wednesday, April 1, in San Antonio to explore the most impactful R&D related to end-to-end interoperability for the electric sectors – solutions that could take anywhere from six months to three years to accomplish. On the table will be five topics for further discussion including: Open Field Message Bus (OpenFMB), Enterprise Architecture, Communications Architectures, Open Application Platforms, and Cyber Security Architecture.

With the rapid pace of change of information, communication and cyber security technologies, it is important to bring all stakeholders together to understand the evolving electric industry needs and emerging technology innovations to prioritize R&D necessary to achieve End to End Interoperability for the grid. The partnership between CPS, Duke, EPRI and NREL aims to achieve that goal.

References

1 Distributed Energy Resources (DERs) include roof-top photovoltaics (PV), battery storage, smart appliances, plug-in electric vehicles (PEV), microgrids, and advanced demand response tools

2 Duke Energy's Coalition of the Willing project as demonstrated at DistribuTECH 2014 as well as NREL's request for proposal to demonstrate open-source, standards-based, interoperable platforms that can integrate renewable energy sources. http://www.greentechmedia.com/articles/read/duke-energy-and-the-coalition-of-the-willing

3 Centralized functions such as a billing system, outage management system (OMS), or distribution management system (DMS).

4 EPRI, "Transforming Smart Grid Devices into Open Application Platforms," 3002002859, July 2014, http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?productid=000000003002002859

5 "With Strain on Electric Grid, a Push to Prioritize Conservation" at http://www.nytimes.com/2014/01/24/us/with-strain-on-electric-grid-a-push-to-prioritize-conservation.html?_r=0

6 "CPS Energy Recognized for Renewable Energy Progress, Customer Service as New Energy Economy Thrives" at http://www.marketwatch.com/story/cps-energy-recognized-for-renewable-energy-progress-customer-service-as-new-energy-economy-thrives-2015-01-14

7 Open Industry Workshop Summary: http://www.cvent.com/d/kx1SOhFhiUK2r_s7M2uvkg/snh9/P1?

About the authors

Raiford Smith is Vice President of Corporate Development and Planning with CPS Energy in San Antonio, TX. He has 24 years of diverse experience in the utility industry, is a licensed North Carolina attorney, and has a BS in Computer Science from the Univ. of Georgia, an MBA from the University of Virginia, and a JD from the Charlotte School of Law.

Matt Wakefield is Director of Information, Communication & Cyber Security at the Electric Power Research Institute. He has more than 25 years of experience in the electric industry and his responsibilities include furthering the development of a modernized grid through application of standards, communication technology, integration, and cyber security.

Stuart Laval is a Manager of Technology Development in Duke Energy's Emerging Technology office, where he leads the open field message bus (OpenFMB) reference architecture and its smart grid interoperability platform. Additionally, he has spent over 10 years at manufacturers of utility equipment, cellular radios, and power semiconductors. Mr. Laval holds Bachelors and Masters degrees in Electrical Engineering & Computer Science from MIT and a MBA from Rollins College.

The Power of Collaboration in Power Services

Just what strategies are available to improve High-Voltage Circuit Breaker equipment while holding down costs?

By Monica Lambe

High-voltage circuit breaker equipment represents a substantial investment for any utility, especially when coupled with today's sophisticated new grid technologies. So when it comes to maintaining or replacing these breakers, all options have to be considered. Often, the most cost-effective option is to partner with a full-service OEM expert who will employ the latest technologies during maintenance cycles and seek life extension opportunities, such as retrofits or component replacement.

In some cases, total replacement, removing obsolete equipment or technology, may be best. Remote monitoring and advanced inspection techniques, such as radiography, will often eliminate the need for intrusive maintenance programs, or early replacement altogether.

There are several well-developed service strategies available today to suit the many different maintenance and replacement scenarios encountered in the high-voltage circuit breaker world.

To retrofit is to exchange worn parts or outdated components while maintaining the original plant and equipment configuration. Often, in a substation, original equipment, such as the housing and busbars, remains in good condition over many years, and it is only the moving circuit breaker parts that need to be replaced. Mechanical equipment wears out long before stationary assets. Retrofitting extends service life without the high costs, major disruption and extended time scales associated with a complete replacement project. The work can also be staged to spread out cost and minimize disruption.

Often, a new breaker will not be compatible with old equipment. In such a case, an OEM or supplier will provide special conversion kits that enable quick installation without structural modifications to the original setup.

Many of today's breaker and drive retrofits ensure that the client receives long-term equipment reliability with the latest technology and minimal outage time – all at a reasonable cost.

Retrofit examples

ABB has supplied several clients with replacement breakers for their gas-insulated switchgear (GIS) instead of revision solutions. Invariably, the replacement breaker was of a newer type and the flange distance and other parameters had to be matched. For example, in the Netherlands (Rijswijk substation) and in Switzerland (Katz substation) first-generation GIS ECKS breakers were successfully replaced with ELK SP 2-1 breakers and AHMA drives. The motivation for the replacement was dwindling repair expertise and the increasing difficulty experienced in sourcing spare parts. In the La Foretaille substation in Switzerland, a similar replacement was undertaken (in this instance an ELK SN breaker type was replaced by ELK SP 2-1), the motivation here being impending high overhaul costs (See Figure 1 –> 1).

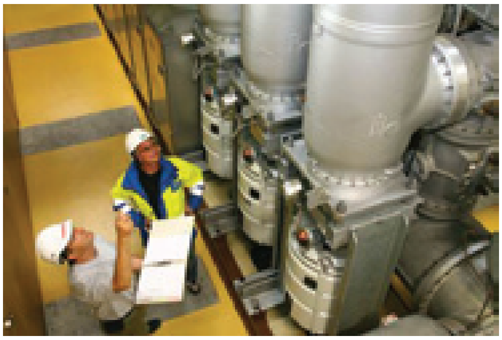


Fig 1: La Foretaille GIS substation in Switzerland. The older-generation circuit breaker type SN was replaced by an ELK SP2-1 with AHMA drive.

Not all older breakers have a new equivalent. However, there are a few new retrofit breakers in the power industry that could replace older breakers of types SL211, SL2-2, SN212, SL3-2 and SN312. Most of these have been type tested as per the latest applicable standards and are manufactured in the controlled environment of a factory.

The EGL 380 kV substation at Filisur, in Switzerland, is the first substation in the world to have such a specifically developed retrofit breaker installed (See Figure 2 –> 2). The utility had originally considered overhaul of their HKA 8 drive, but decided instead to install the new HMB 8 drive. They also replaced their complete SL3-2 breaker and drive with a newly developed retrofit SP 3-1 breaker. This new breaker has only one single arcing chamber – representing state-of-the-art GIS technology – and therefore needed only a (smaller) HMB 4 drive. The utility quickly opted for this proposal – extended substation life, continued availability of spare parts and lower maintenance costs being the convincing arguments. The actual circuit breaker exchange at the site took only two days and the switchgear resumed normal operations with minimal downtime.

Fig 2: Filisur GIS substation, Switzerland. The SL3-2 circuit breaker and HKA8 drive were replaced by a single chamber SP3-1 circuit breaker with HMB4 drive.

One alternative to changing the complete circuit breaker and drive is to change only the drive itself. Iberdrola recently opted for this. In Spain, at the La Muela pumped storage substation, a retrofit drive solution was developed for Iberdrola to replace the old HKA 8 drive on a SL 3-2 breaker (See Figure 3 –> 3). The HKA drive was dismounted from the breaker pole and a new HMB 8 drive was fitted, with necessary adjustments (damping). The homologation tests were conducted onsite. Satisfied with this solution, Iberdrola decided to implement the same retrofit drive solution in the remaining bays at the same substation. And similar drive replacements were made in the Seinäjoki and the Tammisto substations in Finland.

Fig 3: La Muela GIS substation, Spain. The HKA8 drive was replaced with the HMB8 on SL3-2 circuit breaker.

Extension, Upgrades and Retrofits

Today's OEM's and service providers have developed a variety of cost-effective upgrade, extension and retrofit programs that enable extremely low-risk and phased migration to the latest technologies. After a complete site evaluation, most providers will develop a customized implementation plan for migration of the installed equipment.

One good example of this centers on the delivery of two 132 kV gas-insulated ELK-04 switch-bays to the 30-year-old Al Bakir transformer substation in Iraq. This investment became imperative in light of the growing power demand caused by the construction of a steel factory nearby and to be able to adequately interface to the Iraqi grid.

The primary deciding factor was that the ELK-04 design could be adapted to fit into the restricted space available. The utility received competent consulting support during the engineering stage and now has a reliable 132 kV substation, security of energy supply and guaranteed personnel safety. The previous infrastructure was kept intact, and further extension is now simplified, thanks to the use of standardized adapters.

Asset optimization in New York

Industry needs are changing as resources become limited. As a result, established consulting services for and engineering expertise in remote monitoring of all critical substation diagnostic metrics have come into play. One such service combines ABB's universal breaker monitor with deep operational and diagnostic expertise to provide real-time asset optimization and to allow remediation prior to failure.

This approach was taken recently within New York's electrical power grid, which is highly dependent upon the health and reliability of the high-voltage cross-state ties between the NYISO's transmission owners, such as the 362 kV lines connecting Rochester Gas and Electric (RG&E) with New York Power Authority. To help enhance the reliability of this transmission corridor, RG&E has equipped its type PMI capacitor bank breakers, which support the critical east-west tie, with real-time remote condition monitoring, and has also instituted proactive maintenance practices. Of particular interest for first-trip analysis of the transmission line breakers was acquiring a means of recording all trip and close operations, as well as the timing statistics, of those breakers.

The company equipped a fleet of 18 RG&E 121 kV and 362 kV PMI breakers with the asset optimization (AO) system. The system monitors a myriad of breaker status and performance parameters via wireless communication. Data from each breaker is gathered by a proprietary circuit breaker sensor called CBS. Each CBS has been paired with a cellular communicator – decidedly the most cost-effective means of delivering data to a central office, especially from substations lacking a network structure. The CBS-based monitoring approach was especially appealing to RG&E since the units and their wireless communication architecture function independently of the utility's transmission line operating and control system. That separation exempts the monitoring system from NERC-CIP (North American Electric Reliability Corporation's Critical Infrastructure Protection plan) requirements. The accumulated CBS data is processed at RG&E's central office by the AO system, which delivers real-time, independently accessible data to detect circuit breaker health and performance conditions before a failure occurs. The AO system thereby assists circuit breaker problem diagnosis and offers corrective recommendations. Its alerts vary in complexity from identifying status changes in an intelligent device to identifying abnormal conditions. The system includes an independent ABB redundant archiving system to ensure reliable storage of long-term data. With this reliability improvement RG&E was able to obtain a rate increase from the local regulatory commission.

Radiography

Radiography is an x-ray imaging technology, employed here in an external environment that captures detailed digital images of a circuit breaker's critical internal components. These images are then reviewed by OEM experts, who check dimensions and tolerances against original component and assembly drawings. Radiography eliminates the need to breach the sealing system of the equipment being diagnosed, thus increasing equipment reliability and making infiltration of external contaminates a nonissue.

Call Henry Inc. is the high-voltage on-site support service contractor at the NASA Glenn Research Center in Cleveland, Ohio. The Center leads NASA's research and development in the area of aero-propulsion and specializes in turbo-machinery, power, propulsion and communications, while also conducting research in various microgravity science disciplines. Obviously, power supply reliability is critical to such a facility.

In February 2006, Call Henry contacted ABB on behalf of the center regarding the health of their 26 ABB 38PM40-20 SF6 power circuit breakers. A review of the maintenance data carried out by the center and Call Henry highlighted the fact that many of the center's circuit breakers were between 10 and 14 years old, with one breaker having completed over 2,700 operations during its lifetime. It was apparent that these breakers were working hard and were due for an internal inspection.

A site visit was coordinated between the center, Call Henry and ABB in order to perform the inspection. The work scope consisted of external diagnostics testing, heavily featuring the use of radiography. The driver for this approach was a desire for cost and outage time reduction, while certifying the long-term integrity of each breaker and, more importantly, its power supply. The radiographic inspection resulted in entry being made to one breaker to remediate a hardware problem and reduction of the SF-6 gas moisture content in seven others. Nineteen were spared any entry or intrusive maintenance whatsoever and over 380 man-hours of intensive, internal inspections were saved. A crane, with operator, and gas cart rental were also saved.

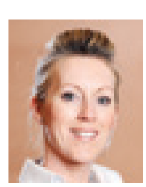
The external diagnostic testing and resulting maintenance ensured continued and reliable operation of the center's fleet.

Replacement

Equipment can be completely replaced at the end of its service life, or if better technology has become available. In the case of generator circuit breakers (GCBs), upgrading the turbine and generator will also necessitate the replacement of the GCB. GCBs may also be replaced if obsolescence results in non-availability of spare parts or inadequate engineering solutions.

One example of this concerned the spring-loaded hydraulic circuit breaker operating mechanisms in five transformer substations in Kuwait City, owned and operated by the Kuwaiti Ministry for Electricity and Water (MEW). Considering the increasingly critical spare parts situation for the existing operating mechanisms, which are nearly 30 years old, the proposal to replace the existing units with 48 HMB-8 operating mechanisms was positively received by the MEW. An essential aspect of this decision was quality assurance and the guaranteed availability of the related spare parts. As a result, the MEW acquired a dependable spare parts supply, high substation availability and reliability, better personnel safety, uncomplicated adaptation and replacement, and, of course, a simplified operation.

About the author



Monica Lambe is a Market Analyst with ABB in the High Voltage Service business, a part of the High Voltage Products business under ABB's Power Products division. Monica is based in Mount Pleasant, Pennsylvania and Zurich, Switzerland, and has served in various roles at ABB over the past 10 years. She can be reached at: **monica.lambe@ch.abb.com.**

The Sun is About to Set on Substation TDM, Analog and Frame Relay Data Circuits: Are You Ready?

By Mark Madden

There is a big change on the horizon that will impact every utility in the United States, and ultimately worldwide. Telecommunications service providers (what we typically refer to as 'the carriers') are phasing out circuit-switched phone service in favor of more advanced IP/Ethernet-based offerings. This change is a natural evolution of carrier networks toward more efficient technologies, which has been underway for more than a decade. Carriers have no choice, but to migrate to the new networks and standards.

However, a substantial concern that this network evolution presents is that these are the legacy networks that have been used by the utilities for decades. They are used for managing electrical grids; transporting data from substations and other nodes on the grid; and supporting critical applications such as the high voltage circuit breakers that protect the grid (teleprotection), and Supervisory Control and Data Acquisition (SCADA). Unfortunately, evolving to a new network also means finding alternative ways to address performance requirements of these systems, which is not as simple as switching from one data service to another – modern IP/Ethernet technologies are fundamentally different from traditional circuit-switched networks.

Though replacing electrical equipment such as Remote Terminal Units (RTUs) will likely be unnecessary, much of a utility's grid communications equipment will no longer be compatible with the new services and will need to be re-engineered and replaced. Replacing this equipment is expensive and highly disruptive to utility operations, so the migration needs to be managed carefully to avoid unnecessary cost, complexity and risk.

For decades, circuit-switched carrier networks have been providing a reliable, deterministic, and relatively low-cost way to manage the transmission and distribution grids. The shift by the carriers away from the analog and Time Division Multiplexing (TDM) technologies – which utilities have relied on to manage their transmission and distribution grids – to packet-based networks is a consequence of rapidly shrinking demand for traditional home telephone service. It is an organic, market-driven pressure on the carriers that is fueling this transition and it cannot be stopped.

The reality is that carriers are no longer generating sufficient revenue from their current circuit-switched networks to continue operating them and are continuing to lose customer interest in paying for them, despite the fact that utilities are depending on those networks for mission-critical applications. Instead, carriers are focused on building out their broadband and mobile services revenue and must modernize their networks accordingly.

Carriers have not been shy about their plans. AT&T, for instance, recently distributed a 'withdrawal matrix' that made clear where and when analog, TDM and Frame Relay services would no longer be available. They shared plans to end support for all non-Ethernet access channels (such as DS0, T1, T3, OC-3, OC-12 and OC-48), all non-Ethernet private lines and Ethernet private lines slower than 600 Mbps, as well as, existing teleconferencing services and toll-free features. Required time-frames for withdrawal are as short as 120 days, which means that utilities need to be making plans well before they receive a sunset notification. AT&T plans to complete the transition – across its entire network – no later than 2020.

As a complication, most utilities source a percentage of their TDM and analog data services through multiple carriers, all of which have different timelines and locations for the transition, so a thorough and far-reaching plan is required by the utility to insure that communications services to the substation are not disrupted by the disparity in scheduling by the different carriers.

Also, as the move toward IP/Ethernet is universal, it is similarly affecting the carriers' 'ecosystem' of suppliers and is similarly causing huge shifts in the supply chain for TDM equipment. Equipment manufacturers have for the most part stopped developing TDM equipment, and instead are focused on delivering IP-based solutions. At some point not too far in the future, this equipment will not only be impossible to get, but it will become difficult to maintain.

The Sun is About to Set on Substation TDM, Analog and Frame Relay Data Circuits: Are You Ready?

Finding technicians who are familiar with the analog and TDM technologies in order to repair them is becoming a major challenge as technical training programs focus on newer technologies. As a result of the shortage of both equipment and maintenance personnel, older networks are breaking down with greater and greater frequency.

Utilities are already in a situation where they experience reduced service hours and longer wait times to schedule service, and in some cases are refused service altogether, particularly when asking for new TDM circuits or renewing existing leases. In addition, they are also seeing financial disincentives to continuing with TDM connections. As the operational costs to maintain these systems increases, so does the cost to lease these services. This means the costs to the utility will begin to rise dramatically as these services become less and less profitable for carriers to continue providing.

What's next?

Utilities cannot continue to rely on the TDM and analog circuit technologies that they have historically depended upon. Unlike 'Smart Grid' which has largely been a voluntary evolution of the electrical grid, the sunset of TDM and analog circuits are not within the control of the utility, so doing nothing is no longer one of the options. Carriers have already started to send notices that service will be discontinued in certain service areas.

As Connie Durcsak, president and CEO of the Utilities Telecom Council (UTC) details the evolution, "'Flying like confetti' is how one utility described their TDM and analog circuits termination notices from their commercial carrier providers. With carriers ending decades of support to utilities through the phase-out of TDM and analog circuits, utilities are left scrambling to identify replacement solutions. Given the vast number of circuits at risk, this task is not insignificant. It will be a costly and resource intensive exercise. And any replacement solutions will need to be identified quickly to assure continuity of service of SCADA, protective relaying, and other mission-critical applications. Certainly, wireless technologies will be a solution of choice for many remote areas or in cases where rights-of-way are challenging. However, the lack of available licensed spectrum prioritized for utilities and other critical infrastructure providers is a real concern. UTC is working with utilities and their technology partners to ensure that utilities have the information they need to weigh their options fully and to ensure that policy makers understand the impact of this situation on the nation's energy and water resources."

While describing the termination notices as 'flying like confetti' might be a bit dramatic, it sends a very clear message that the tipping point on these services for the carriers has been reached, the transition process is underway, and this process is certain to accelerate quickly.

The reliability of electric service is at risk and as a result utilities need to develop a transition plan, ideally one that does not involve a dramatic increase in costs. Unfortunately, upgrading to higher bandwidth, IP-based solutions offered by carriers will almost certainly result in an increase in monthly operations and maintenance costs.

Why? The options offered by carriers tend to be much more expensive, such as fiber access (where it's available), IP over copper, or wireless cellular broadband (which is relatively unproven for mission-critical services). The fixed network service options, fiber and copper-based, typically cost anywhere from 4 to 10 times what existing TDM-based circuits cost. Moreover, they provide far more capacity, at much greater cost, than what is actually needed by most current utility applications. Worse yet, utilities may be required to pay substantial amounts to the carrier to install fiber or upgrade the copper infrastructure serving their substations and other locations.

For many utilities, the alternative offer by their carrier is likely to be a dedicated IP/Ethernet link that could cost up to $1,500 a month, in comparison to the $100 to $300 a month charge for their existing circuit connections. Spread this cost delta across a large service area and the increase in operations expense becomes fairly dramatic.

Of course, lower cost wireless solutions are being offered and these will certainly meet many utility data communications requirements. They are not, however, as predictable nor as reliable as the traditional services they are intended to replace. However, they provide service to delay tolerant and low-value utility assets. That said, consider the following scenario:

> *Hypothetical Transmission & Distribution Utility, 'Universal Electric Service Group' depends on circuit-switched DS0s and sub-rate Frame Relay connectivity to monitor the Dynamic Line Rating (DLR) sensors that are measuring the heat load and sag of a high-voltage transmission line. Recently, the carrier serving Universal gave them a 120-day notice of service sunset and offered either a multi-megabit bandwidth fiber-based Ethernet service or a low-cost cellular service as the replacement options. Without the Public Utility Commission's approval for an increase to the rate base, the utility could not afford, and did not have sufficient time, to extend their private fiber and microwave network infrastructure, nor was it able to afford to implement a reliable fixed broadband digital connection from the carrier, so Universal scrambled to replace the service with the carrier's cellular data service, having no other cost-effective means to remotely monitor the line.*

A few months later, a localized power outage due to a thunderstorm caused a loss of power to the carrier's cellular tower serving the DLR sensor. After 4 hours the batteries failed in the cellular tower and the neighboring cell towers became congested with consumer traffic as consumer phones switched over to the other nearby towers that still had power. This caused the transmission line's DLR sensor to be unable to get a cellular connection which left the line unmonitored by Universal's transmission management system for an extended period of time. The transmission line then overheated due to increased electrical load from neighboring areas as residents returned home from work, plugged in their Hybrid Electric Vehicles, and turned on air conditioners and pool pumps in areas not affected by the local outage. This caused the line to sag into an untrimmed tree and short to ground. This in turn tripped the differential protection breakers at the nearest two substations, creating a surge of electrical load on neighboring transmission lines which in turn tripped their breakers from the additional load. Finally, and in a matter of just a few minutes, it ultimately cascaded across the grid causing wide area outages including significant areas in several neighboring states.

Sound implausible? Although the root cause is a little different (communications failure vs. lack of line sensor), this scenario has played out before, in 2003, when a failure blacked out large sections of the bulk electric grid from Ohio to New York and into Canada.

It is possible, of course, for utilities to establish their own private TDM network to support applications such as SCADA, teleprotection, security, substation voice and others; although, there will be fewer and fewer vendors available to support these networks as suppliers naturally move to next-generation technologies. The supply chain is rapidly shrinking, not growing.

In contrast, certain packet-based technologies, such as IP/MPLS and Carrier Ethernet are well suited to the requirements of utilities in utility-owned networks. In a private network designed and implemented as 'Utility-Grade' these technologies can be deployed to meet the needs of the utility well into the future. In fact, these are fundamentally the same technologies that the carriers themselves are using to provide alternative service options – just without the strict traffic engineering controls on the quality of service, deterministic (consistent) path and delay that is required for many SCADA applications and any teleprotection service that the utility would put in place for itself to meet its own requirements. The carriers design systems that meet the requirements for the bulk of their customers, but not necessarily all of them, and utilities are outliers when it comes to network communications requirements.

As a result, now is the time when utilities need to consider whether it is most cost effective to continue to rely on carriers to address their critical operational needs and at what percentage, or whether it might be more appropriate to consider extending and transitioning their own privately-owned telecommunications farther out into the field, thereby taking control of both their costs and evolution plans.

So, how can utilities best ensure that they can continue to meet the expectations of their customers? Naturally it depends on the particular situation of the utility, but generally speaking, the business case for building and maintaining a private network becomes more compelling as the cost of leased services increases. Considering the growth in operations and maintenance costs in coming years, building a single, utility-owned network, or even extending that portion of the utility's existing network further out into the field may well become an increasingly attractive option in terms of reducing overall costs and ensuring continuity of operations.

As importantly, it's not entirely clear that carriers will be able or willing to address the utilities' stringent latency and deterministic requirements, particularly since utility applications are a small minority in comparison to average business applications, which is the bulk of their business. Ultimately, however you slice it, unless they have a viable, reliable, long-term alternative to TDM and analog circuits, utilities will not be able to reliably and efficiently supply power to all of their customers.

There are a variety of ways to approach this end goal, but all involve utilities moving sooner rather than later, and coming up with a proactive plan before their hand is forced. The future is coming and it is coming quickly. Utilities need to come up with a plan to transition from their reliance on carrier-provided TDM services, equally quickly. They have the opportunity to control their own destiny, but time is of the essence, and they need to move now.

About the author

Mark Madden is the Regional Vice President, North American Utilities, Alcatel-Lucent. He has over 25 years of experience with leading companies in the Information Technology and Telecom industries, and has diverse business, and technical expertise gained through a variety of positions in the industry. Mark is currently responsible for Market Strategy, Strategic Partnerships. and Business Development in Alcatel-Lucent's Americas Region Energy Markets.

Mark is an accomplished Network Architect with a strong background in Network Capacity and Application Performance Management, as well as, Network Management Systems and Program/Project Management. He has been responsible for the formation and establishment of Business Consulting, Network Application Performance services, and Application Integration Services at Alcatel-Lucent. Mark has also consulted to a wide variety of companies on Network Performance Management, Network Architectures, Network Management Systems and Processes, and Communications Application Development.

Three Challenges with the Current State of the Smart Grid

By Scott Foster

The current state of the smart grid is not enough for the needs of utilities and their customers. Today's 'smart grid' is not truly a smart grid, but simply smarter metering. The components that make the grid smarter – networking capabilities, digital controls, distributed intelligence, smarter failure avoidance strategies, etc. – have not yet arrived in their best form. These components derive most of their value because they produce data that utilities have never had access to in the past. But for now the data that is being created is essentially useless. There is currently no way to understand this data, nor are there existing ways to implement it in meaningful ways. And with the current expectation that energy demand is projected to grow by more than a third of its current amount by 2035,[1] it's about time we all start paying attention.

This is not to say that there haven't been attempts to modernize the grid. It's just that those that have been introduced have left utilities and customers wanting more. For example, Northeast Utilities (NU), a major utility serving Connecticut, Massachusetts, and New Hampshire consumers, criticized the state of Massachusetts in early 2014 regarding its advanced metering plan, claiming it had 'no rational basis for the implementation of advanced metering infrastructure (AMI).' NU felt that Massachusetts' proposed electrical grid modernization plan, one that would require the utilization of advanced metering or smart meters within the state, would be too costly for the insignificant amount of functionality it would bring to utilities and customers.[2]

While most utilities would disagree with NU's position, it is worth considering. If utilities were able to properly leverage the data that these meters collect to actually improve billing, significantly decrease outages, etc., then there would be no question about the value of implementing them. But with the state of the technology available, it is extremely difficult to obtain useful data from the grid today.

Why is data so difficult to obtain from the current smart grid?

Currently, utilities networks are able to access very little of the data that is coursing through their infrastructures. The primary reason it is difficult to obtain useful data is because of the massive amounts of data that come from customer systems, grid operations systems, and enterprise systems. This is very different than the complications that arise from smart metering, which is more on the customer system component side. But there are thousands of other points throughout the smart grid where data collection comes into play. And for the most part, data is simply sitting there in space, not being utilized in a meaningful way.

It's not only that the data cannot currently be accessed, but that once upgrades are made to utility networks, a resulting side effect is that electricity providers will all-of-a-sudden be expected to process much more information than they're accustomed to processing.[3] And adding more data to analyze can be extremely overwhelming.

There are some sophisticated analytics technologies that are currently being used to collect and process this data. But the information that is collected is isolated into separate pillars that do operate cohesively. This makes it nearly impossible to recognize the more complex relationships between the data within each. So it is challenging to achieve one cohesive picture of an electric utility's data and how it can be applied to operations.

What are the most common types of outdated technologies that are currently being used by electric utilities?

Though there are probably too many to name, the three that most people in the industry immediately think of are:

1. Operating a distribution grid by looking at only the substations. If utilities could add data from endpoints (meters) and intermediate points (reclosers, breakers, transformers, etc.) to this picture, they will significantly modernize their operations.
2. Somewhat related to the previous point utilities are still operating distribution systems without the voltage information from the endpoints, which creates a potentially dangerous blind spot.
3. Collecting meter readings only as needed to support customer billing. Utilities should be able to collect meter readings at any given time, and leverage that data to make short or long-term decisions about operations.

There are several solutions that can help improve the decades old infrastructure

The most compelling solution is by far the use of the cloud, which provides easily configurable computing power so that data storage can be easily added, to almost any level, to store the data needed for the analytics. With the cloud, there is the promise that software and other digital technologies will be able to provide utilities with solutions that can reduce cost and increase reliability and transparency, and even save more energy for utility companies and users.[4]

Utilities can also use the free, Java-based programming framework, Hadoop, to support the processing of large data sets in a distributed computing environment. This allows data analysis tasks to be spread over as many separate processors as needed, no matter how large the data sets, or how complex the analysis. The user always sees a responsive tool. Cloud data storage can be scaled to suit the volume of data and the expected lifetime of the data. Cloud systems connectivity can also easily support users operating from desktop computers in the office, from laptops in vehicles, and from tablets or even from smart phones used by field workers.

Data analytics can solve these issues and use cases

Data analytics can help to determine the most efficient operation of distribution equipment, which includes benefits like optimizing voltage settings to maintain specified voltages at customer meters while minimizing delivery system losses and power acquisition costs. Another example would be the ability to correlate blink counts at meters to identify fault locations or analyze outage reports to locate tripped circuits.

It can also be used to monitor electric system operations to alert operators when performance trends indicate failing components or required maintenance, which ultimately reduces system failures and emergency repair costs.

Lastly, data analytics can benefit the customer directly by delivering useful information that helps to reduce their energy consumption and energy costs, particularly when complex TOU or CPP rates are available. These can typically be difficult for the customer to evaluate, but 'bottom line' analytics can make the choices clear. In the same vein, analytics can provide guidance to the utility during new rate evaluations, showing the results of alternative rate structures being considered.

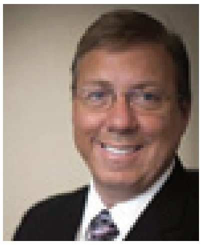
Unlock your data for future decision making!

Software solutions offer utilities an opportunity to innovate and update their existing infrastructures in a non-invasive manner. With the ability to access the data flowing through the power grid, some of the benefits utilities would experience include:

- Ability to access and unlock new products
- Widening the types of services a utility is able to provide
- Improved asset deployment and operating efficiency
- Enablement of active customer participation
- Ability to accommodate all generation and storage options
- Ability to fulfill the demand for power that is expected to increase with the changing digital landscape
- Capability to predict and respond to system disturbances
- Ability to anticipate and operate during natural disasters
- Resilience to physical and cyber-attacks

But all of these benefits are powered by correctly harnessing the unstructured data in a utility's networks. Being able to do so not only creates the opportunity for smarter decisions, but faster ones that are based on accurate and timely analytical analysis. These solutions can enable a flow of information which can transform raw data into useful, comprehensible information, leading to better business decisions for the utilities and a better experience for the customers they serve.

About the author



Scott Foster is the president and CEO of Delta Energy & Communications, and has over 29 years of experience in the energy sector.

References

1. World Energy Outlook 2013 Factsheet (2013) *http://www.iea.org/media/files/WEO2013_factsheets.pdf*
2. Investigation by the Department of Public Utilities on its own motion into Modernization of the Electric Grid, D.P.U. (December 23, 2013) *http://haltmasmartmeters.org/wp-content/uploads/2014/01/NSTAR_R12-76-Comments-7986-POSTED01172014_HIGHLIGHTED.pdf*
3. Gomes, Lee. 9May 25, 2011) The Challenge of Big Data on the Smart Grid. MIT Technology Review. *http://www.technologyreview.com/news/424088/the-challenge-of-big-data-on-the-smart-grid*
4. Enabling the SmartGrid through Cloud Computing. (April 2012). *http://energy.gov/sites/prod/files/Friday_Trinity_Ballroom_3_0855_Primetica_final.pdf*

Beer Losses and Grid Losses

By Rudi Carolsfeld and Mike Rowling

Dark lager beer tastes good. With a little bit of imagination we can also use beer to illustrate something that few Big Data system vendors want to admit when promoting meter data analytics systems to electricity distribution companies. Big Data is missing a key thing to be successful in the meter data analytics paradigm: data.

The origin of this bold claim can begin with some parallels that can be drawn between beer and electricity. Bring enough propeller heads together and the discussion may turn to the role of In-Grid Data Analytics[1] and how beer is a lot like electricity:

1. Electricity is easy to consume but takes resources, skill, time, and effort to generate
2. A complex network of transformers and wires are required to distribute electricity, and beer needs trucks, kegs, and bars
3. Both don't last long, don't store well, and should be consumed quickly
4. At least one movie has been made about stealing electricity[2]
5. When it comes to Big Data, analyzing the consumption patterns of end users of beer will make it difficult to find problems with upstream distribution and theft, just like electricity.

This last point begs the question: will the billions invested by distribution companies in smart metering, meter data analytics (MDA) and Big Data help them find losses and theft in the distribution grid?

To combat theft, the beer distribution company might install surveillance cameras in the shipping bay, in delivery trucks, and near storage and refrigeration units. It is far more difficult to combat electricity theft because the electricity constantly flows through hundreds of miles of power lines strung throughout the countryside. There simply is no cost effective way to install enough monitors or sensors to determine exactly where and when pilfering takes place.

Smart meters and MDA are often cited as providing a means of identifying all types of energy theft. Indeed a smart meter may send an alert if the end user tampers with the meter. MDA systems use various algorithms to try to spot anomalies; for example, low voltage outliers among multiple consumers on the same line may indicate a meter bypass. Smart meters and MDA certainly can help.

But questions arise:

- What can be done if no smart meters exist due to budgetary limits?
- What can be done if the smart meter is not registered in the billing system?
- If the meter has been installed wrong (i.e. wiring incorrect either accidentally or intentionally)?
- If the billing system is incorrectly set up (e.g. wrong billing multipliers).

Even if the smart meter is installed correctly and registered correctly, most people are still smarter than smart meters and the serious electricity thief is likely to start looking for weaknesses in the distribution system upstream from the point of sale.

The analogy with beer may be a 'smart pub:' install video cameras or an alarm system if an unauthorized patron tampers with a keg or doesn't pay for his beer. If someone were to siphon beer out of a keg, the pressure (voltage) might be lower than expected at the tap, and a system could be designed to find this – even though there are probably fewer pubs willing to pay for this than there are utilities willing to pay for smart meters. At some point, though, the serious beer thief is more likely to look for weaknesses in the distribution system upstream from the point of sale.

MDA systems do fairly well when it comes to finding anomalies in consumption patterns that might point to an underlying problem. When the consumption patterns of a large percentage of electricity users are cross-referenced with Customer Data Analytics (CDA), it may be possible to find additional unauthorized consumption. In recent years, major Big Data system vendors that are targeting smart meter infrastructure (SMI) have chosen to invest heavily in CDA and MDA systems.[3 4 5]

A concern raised by some distribution companies, however, is that the Big Data CDA/MDA approach simply generates another set of data that cannot be acted upon, or generates too many false positives.[6] Data quality, communications errors, and the large number of alerts and flags can make it difficult to pinpoint the problem. The even bigger challenge, however, is that theft and losses that occur upstream are very difficult to measure using data collected by a smart meter. There is no easy way to *audit* the distribution grid using this approach.

Return to the beer analogy for a moment: checking the consumption patterns of a large percentage of beer drinkers will never give you an indication of where and when beer may have been diverted upstream. There is no easy way to know when or where a delivery truck was hijacked and kegs of beer stolen from the back.[7] There's simply no data to help. It is the same problem with using Big Data analytics of energy consumption: these Big Data solutions lack data.

In-Grid Data

The data that is still needed for success in the fight against theft and losses in the electricity distribution grid is called In-Grid Data. Every data source that provides load data from within the grid may be classified as In-Grid Data.

A number of vendors have introduced sensors that can be used to generate *In-Grid Data* by installing a sensor on the medium voltage lines.[8] Some vendors have introduced sensors to be installed on the low voltage side of transformers.[9] [10] In general, this data can be used to compare delivered energy against the aggregate consumption measured by the downstream billing meters.

Problem solved, right? Just install sensors on MV and LV lines to permanently audit energy consumption and metering at each point. The cause of any loss (including theft) can always be found if there is enough In-Grid Data between the generator and the point of sale. In our beer analogy, we can install a camera in every truck, warehouse and refrigerator – this would give us a constant monitoring system from the brewery to the point of sale.

Sadly, the problem is not solved because unlike beer in a fleet of delivery trucks, it is generally cost prohibitive to install permanent In-Grid Data sensors throughout the distribution grid. Most companies already struggle with the business case for smart metering – adding more in-grid sensors needs to be carefully planned to focus scarce budget dollars on the highest risk areas.

In-grid data - the better way

A distribution transformer in North America may have up to 10 consumers on one transformer, so a distribution company with 1,000,000 consumers may require over 100,000 LV transformer meters. Fully loaded cost for each installation: maybe $1000. If the distribution company wants to buy MV sensors to measure the line load for every 10 transformers (100 consumers), they would need 10,000 line sensors. Fully loaded cost for each installation: maybe $2000 per phase. The total cost can be $120M or more.

Spot checks can help

The best approach to obtaining useful In-Grid Data is to perform spot checks on the distribution system, and focus precious resources on the highest risk areas.

Rather than a camera on each delivery truck and so on, we can instead take statistically relevant samples of how much beer was loaded onto the trucks, how much came off, how much went into the bar, and how much was sold. Those In-Grid Data points can then be used to determine if there are losses in the distribution system. In high-risk areas, more sampling will serve to pinpoint the cause of the loss.

Similarly, spot checks may be carried out in high-risk segments of the electricity distribution grid. Measuring the line loads for a week or two in strategically selected locations will give a good data set for consumption patterns in that area. Combined with additional information about the consumers in the same area, this In-Grid Data can then be used to determine the likelihood of losses.

This is not an unusual thing to do: risk assessments and risk-based decision-making is widely used in the financial and insurance industries where Big Data problems abound. When fraud and abuse occurs in these industries, the company will collect more data selectively – e.g. by carrying out a field investigation in a particular neighborhood to see if an insurance claimant has a valid claim.

The highest risk areas may be selected using the results of MDA and CDA systems, of outage management systems, asset management systems, and a wide range of other metrics. Of course, suitable case management and investigation management tools are required to keep track of the In-Grid Data and results.[11]

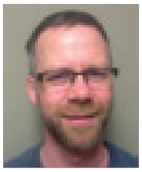
Meter Data plus In-Grid Data

The lessons we can learn from protecting our fictional beer distribution system can help us reduce losses in our real life electricity distribution grid. We just need to keep in mind that Big Data based solely on smart meter data might not be enough – only with In-Grid Data analytics can we be confident that losses of all types can be reduced.

Problem solved. Cheers!

About the authors

Rudi Carolsfeld is Executive Vice President of Global Sales & Alliances at Awesense Inc. He has more than 20 years of experience solving Smart Grid problems. Rudi lives in Victoria BC and enjoys visiting the Great Canadian Beer Festival.



Mike Rowling is Chief Technical Officer at Awesense Inc. He has more than 20 years of experience solving Data Analytics problems. Mike has been a volunteer at the Great Canadian Beer Festival since inception.

References

1 *http://www.energycentral.com/gridtandd/metering/articles/3013/True-Grid-Intelligence-uses-in-grid-data-analytics-to-cut-grid-losses-and-power-theft*
2 Katiyabaaz (2013)
3 *http://gigaom.com/2015/01/07/silver-spring-to-acquire-energy-data-startup-detectent/*
4 *http://www.oracle.com/us/corporate/press/1885589*
5 *http://www.siemens.com/press/pi/icsg201112003e*
6 *http://electricenergyonline.com/show_article.php?mag=102&article=833*
7 *http://kitchener.ctvnews.ca/three-arrested-in-theft-of-beer-truck-some-beer-recovered-1.2015260*
8 A few representative vendors: *http://www.awsense.com/solutions.html#raptor, http://grid-sentry.com/, http://www.sentient-energy.com/*
9 *http://www.sensorlink.com/*
10 *http://grid2020.com/*
11 See *www.awesense.com* for information on the True Grid Intelligence system.

THE BIGGER PICTURE

BY DON ANGELL

Doble Engineering Company Acquires ENOSERV to Meet the Needs of Customers in a Changing Regulatory Environment

Since the 1960's, electric power systems – and the demands on those systems -- have grown substantially. Many power grid assets are getting old enough to retire, as is the baby boomer generation that has been servicing and caring for these assets. With all these factors coming to the surface, it's clear that the power industry is entering into a perfect storm of challenges.

The Federal Energy Regulatory Commission (FERC) and the North American Reliability Corporation (NERC), two of the electric power industry's regulatory bodies, are well aware of the critical role the power system plays in society. They are actively trying to ensure reliability of the electric power grid by working alongside leading power organizations to put in place meaningful standards. This work includes keeping track of all operating issues that occur on the transmission system across the U.S., as well as developing and enforcing reliability standards and policies.

FERC and NERC recognized that many of the electric power interruptions and problems that occurred on the grid were related to issues with protection and control systems. In order to better maintain the reliability of the transmission system, they developed critical infrastructure regulations that required utility companies to put in place and follow protection system maintenance. These regulations were approved as NERC PRC-005 on March 16, 2007 by FERC and became enforceable within the contiguous United States on June 18, 2007.

NERC provided a grace period for companies to update their protection system maintenance programs to meet the new regulations, giving companies time to ensure that their programs are in place and are completely auditable. If not, the consequences are steep – fines can reach up to $1 million a day for noncompliance.

Many companies have their strict maintenance programs set in place, yet are not prepared with an organized process to provide auditable results. The need for support and solutions is clear. Companies throughout the power industry are adapting to the changing regulatory landscape – turning to solutions providers such as Doble. Its recent acquisition of ENOSERV is one in a series of the steps the company is making to provide clients with a suite of options that provide answers for the field crews through the corporate office, including those which can help them build comprehensive and easy-to-use protection system testing programs.

Partners in Protection

ENOSERV became a division of Doble in January 2015. Long-time industry peers in the protection solution space, Doble and ENOSERV share many of the same customers, and the organizations have a mutual understanding and appreciation of the others' strengths.

"We knew that Doble would be a good fit to work with given their long history in the test and maintenance space," said Dennis Loudermilk, ENOSERV's founder and general manager. "We are confident that with their knowledge and expertise that we'll be able to continue to create innovative and reliable solutions for our customers."

ENOSERV was founded in 2001 and is based in Tulsa, Okla. From the beginning, Loudermilk saw the opportunity to help utilities manage relay setting and maintenance information, and pioneered the idea of agnostic system protection testing.

ENOSERV's protection software embraces a vendor agnostic approach; this is also an approach that Doble uses with systems such as its asset risk management system. Regardless of which vendor makes a customer's test or monitoring equipment, these programs can accept the data. This customer-centric perspective makes these organizations a natural pairing, not only for their present offerings but for continued growth into the future.

This agnostic approach is becoming increasingly important as more and more utility companies merge together. Companies could be using different equipment throughout their divisions, but that transition becomes less of a headache if software solutions can accept the data from a variety of sources and across manufacturers. Being able to seamlessly integrate this data throughout a utility merger helps to ensure that no information falls through the cracks and compromises reliability or regulatory compliance.

Strong Foundations

Doble Engineering Company was founded in 1920 by Frank Doble who recognized the value of running maintenance tests on electrical apparatus, but also of archiving and sharing the data with the industry. That foresight enabled Doble to develop an unmatched knowledge database, containing more than 44 million data points of electrical apparatus test data.

With this data, customers are able to identify trends and possible issues that may arise with their own assets – turning historical data into actionable, predictive business intelligence.

Through its products, services and knowledge-sharing including events such as the annual International Conference of Doble Clients, Doble provides the utility industry with comprehensive asset management solutions, including data, analysis and unbiased recommendations grounded in Doble's position as an independent third party. In this role, Doble is relied upon to help clients minimize risk, improve operations, optimize system performance and reduce costs.

Protection Testing and Data Management

Nationwide, power companies are being identified as non-compliant with NERC Reliability Standard PRC-005 because of a failure to meet the testing schedule deadline. Of the top 11 FERC enforceable standards, the PRC-005 was among the highest-violated this past year. There is a huge need for streamlined testing and maintenance programs, with easy reporting and maintenance tracking.

Companies across the industry are all in very different phases when it comes to the adoption of NERC regulations, and the path to implementation isn't always linear. They need tools to manage test data, and provide critical reports to show proof of continuous NERC PRC-005 compliance – which is no small feat. With the joining of these protection providers, customers have the ability to choose from a suite of software and data management options based on their protection programs.

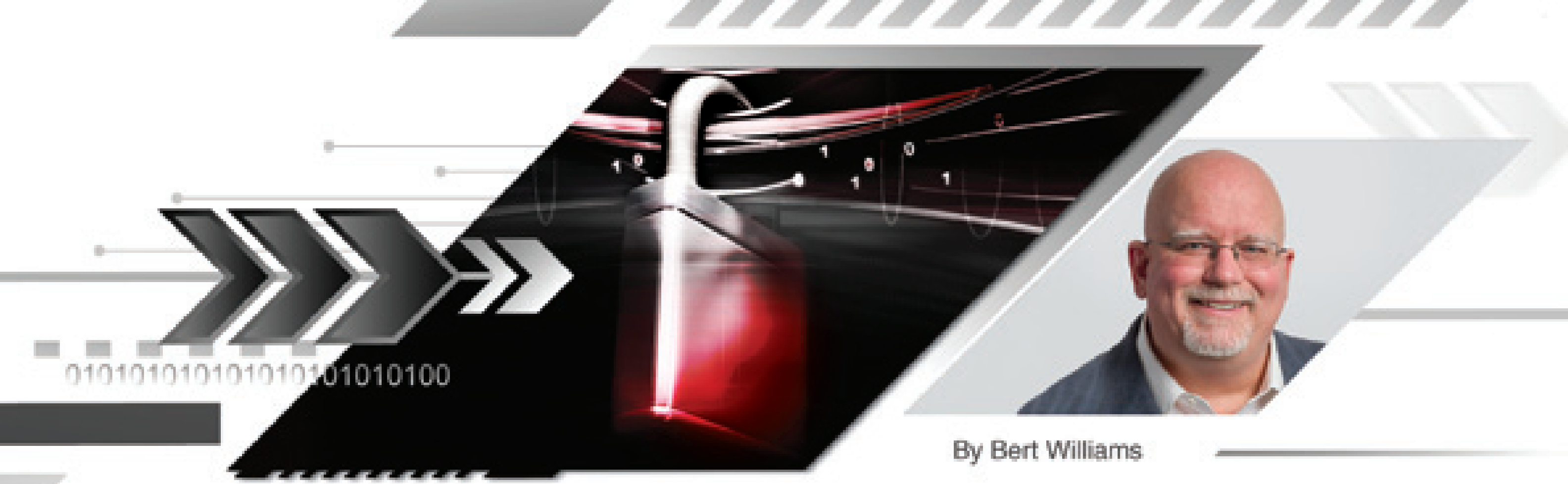
With options that fit their testing programs, customers can choose what makes sense for their business. What they get are robust tools that complement each other, making it possible to test, take action and service their protection system. All while storing test results for easy generation of information for NERC reporting.

Regulatory standards are without a doubt put in place with good intentions. However, the burden and challenges that they place on electronic power organizations are immense and can often seem overwhelming. Together with our new colleagues from ENOSERV, we hope to become the defacto resource for customers as they navigate the new regulatory environment.

ABOUT THE AUTHOR

Don Angell directs Doble's global strategic development, market research and solution management. A respected leader in the electric power industry, Mr. Angell brings to Doble nearly 32 years of experience in utility operations, engineering and asset management. Prior to joining Doble, he directed National Grid's Substation Engineering Services; he previously worked at Exelon, and the Idaho Power Company.

Mr. Angell is a senior member of IEEE and is a member and past vice chair of the Doble's Asset Management committee. He is a member of the Project Management Institute and has presented papers for numerous conferences on asset management, equipment condition assessment and substation automation. Mr. Angell holds a Bachelor of Science in Electrical Engineering from University of Idaho.



By Bert Williams

SECURITY SESSIONS

Modern Wireless Communication Networks:
The often-overlooked building block for utility physical security systems

Substations and other critical utility infrastructure are increasingly becoming the target of physical security attacks, including trespassing, vandalism, theft, and sabotage. In the past two years, there have been dozens of reported attacks on critical utility infrastructure in the U.S. that posed dangers to life, property, reliable grid operation and utility worker safety.

Fortunately, the consequences of most of these incidents were limited; however, there have been more serious attacks. In one, an intruder shot at a security guard. In another, an act of sabotage took a substation out of service for almost a month. Yet another incident resulted in a power outage to 10,000 customers.

Attacks on substations and other critical utility infrastructure have cost utilities millions of dollars in financial losses, equipment damage, material and equipment theft, as well as fines and lost revenue from power outages. The as-yet-unrealized potential for destruction is far worse. According to the *Wall Street Journal*, a study by the Federal Energy Regulatory Commission (FERC) concluded that if saboteurs knocked out nine of the U.S.'s high-voltage transmission substations, the country could suffer a coast-to-coast blackout that could last for weeks, if not months. Also, in a *WIRED* magazine article, researchers reported that physically breaching a substation is an easy way to launch a cyber-attack.

Physical security at transmission and distribution substations, as well as other critical utility infrastructure, can be a significant factor in minimizing or deterring various types of threats. Around-the-clock centralized monitoring and alerts offer early awareness of and visibility into incidents, enabling timely response by the utility. Physical security applications and devices include not only conventional walls, fences and locks, but also surveillance and thermal imaging/night vision cameras, gunshot location sensors, door alarms, keypads and biometrics for access control, motion detectors and intrusion sensors.

Modern wireless networks: the often-overlooked building block

Modern wireless broadband communication networks are an often-overlooked building block for utility physical security systems. The physical security applications listed above require reliable, secure, broadband, multi-application communications between security devices (cameras, sensors, key pads, lights, etc.) in the substation yard, control house and perimeter, and computers located in the utility's operations center. Wireless networks are generally preferred over wired networks because they are much easier and more cost-effective to deploy in substations as they require no trenching.

By centrally monitoring a number of these applications around the clock, utility security personnel can better and more quickly respond to security incidents. It's vital to consult multiple systems to determine how a security breach may have occurred. One example is to use streaming or captured video to confirm what triggered a substation motion sensor. This approach enables utility security employees to screen for and ignore false alarms. It also better equips them to dispatch the correct personnel, e.g., security, maintenance, police and/or fire/EMS, to respond to verified incidents.

Wireless networks requirements: reliability

In addition to the usual reliability features – physical hardening, battery backup, IEEE 1613 compliance, etc. – there are three important elements in providing wireless network reliability in substations: access to RF spectrum, automatic interference avoidance software and mesh routing software.

1. Access to more RF spectrum means that the wireless network has more available channels to use to avoid interference. More spectrum also makes it much more difficult for saboteurs to jam the wireless communication network.
2. Access to more RF spectrum is of little use if the wireless communication network cannot dynamically use it. This is where automatic interference avoidance software comes into play. Using automatic interference avoidance software, a wireless communication network that experiences interference, whether from other legitimate spectrum users or nefarious jammers, can find and use a clean chunk of spectrum in real time.
3. Mesh routing software enables wireless communication networks to be self-healing. Wireless mesh networks can quickly recover from equipment failure and sabotage. Mesh routing can restore connectivity even if saboteurs cut fiber optic and copper cables at the substation. Because mesh routers are small and easily disguised, they are more difficult for saboteurs to take out than wireless point-to-point (PTP) or point-to-multipoint (PTMP) systems, which generally must be mounted on a mast or tower.

Wireless network requirements: secure

Physical security and cyber-security are interdependent. As noted above, physically breaching a substation is an easy way to launch a cyber-attack. Conversely, a cyber-attack can abet a physical attack by taking remotely monitored security systems off line.

Like all networks, wireless communication networks in substations come with potential vulnerability to cyber-attacks. This challenge can be met by implementing a multi-layer, defense-in-depth security architecture that extends to the network's edge. Network cyber-security is best achieved using enterprise tools and techniques.

Wireless network requirements: broadband

Broadband network performance is required for two reasons. First, some substation physical security applications, most notably video surveillance and thermal imaging, are bandwidth intensive. In short, the higher the network's bandwidth, the higher the resolution and frame rate it will be able to support for attached cameras. Second, broadband is needed to concurrently support multiple substation physical security applications. While physical security applications other than video surveillance and thermal imaging do not generally need large amounts of bandwidth when taken individually, the aggregate amount of bandwidth required to support all physical security applications can be quite large.

Wireless network requirements: multi-application

In addition to performance, operating multiple substation physical security applications on a single wireless communication network requires that the network support virtual LANs (VLANs) and quality of service (QoS). Each application can be supported on a separate VLAN that is configured with appropriate security and QoS settings. Using QoS and VLANS, a utility can ensure that latency-sensitive applications get network access priority over other applications with less stringent latency requirements.

Benefits of network-enabled remote physical security monitoring

Utilities can garner numerous benefits by deploying and operating a network-enabled remote physical security monitoring system for the substations and other critical infrastructure. These benefits:

1. Enable prompt, appropriate response to incidents. Remotely monitoring physical security systems, for example, using video to determine if an animal or an intruder triggered a substation motion sensor, enables utility security employees to cut down on false alarms. It also enables them to promptly dispatch the appropriate personnel, e.g., security, maintenance, police and/or fire/EMS, to respond to verified incidents. By providing visibility inside and outside the substation, networked physical security systems enhance responders' situational awareness and safety.
2. Mitigate safety risks and damage from malicious activity. Quick, appropriate response to physical attacks, coupled with audible alarms and warning lights, can cause attackers to flee before they are able to vandalize, steal or damage property at substations.
3. Provide evidence to aid in the apprehension and prosecution of perpetrators. Archived video of security incidents, if of sufficient resolution, can help identify perpetrators and can serve as a witness who cannot be intimidated during criminal proceedings.
4. Deter unauthorized access to property and associated malicious activity. From a utility's point of view, the best attack is the one that doesn't happen. If potential thieves and saboteurs know that a facility is well secured and has networked security systems that can aid law enforcement in apprehending and prosecuting perpetrators, they will likely seek softer targets. Better yet, they may be deterred from criminal activity altogether.
5. Provide an audit trail of authorized personnel entering and exiting the facility. Unfortunately, not all physical attacks on utility infrastructure are perpetrated by outsiders. Maintaining an audit trail of authorized access can deter insiders from malicious activities and provide accountability, should they engage in nefarious acts.

In Closing

Substations and other critical utility infrastructure are increasingly becoming the target of physical security attacks, including trespassing, vandalism, theft, and sabotage. Networked physical security systems at transmission and distribution substations, as well as other critical utility infrastructures, can be a significant factor in minimizing or deterring various types of threats. Around-the-clock centralized monitoring and alerts offer early awareness of and visibility into incidents, enabling timely response by the utility.

ABOUT THE AUTHOR

Bert Williams is the Director, Global Marketing for ABB Wireless and brings 30 years of experience in successfully leading the marketing organizations of networking companies. Mr. Williams was Vice President of Marketing for Tropos Networks from 2002 to 2007 and returned to the company shortly before its acquisition by ABB after working as an executive marketing consultant for four years. Prior to Tropos, Mr. Williams held senior marketing positions at Alteon WebSystems (acquired by Nortel Networks), Qualix Group, SynOptics Communications (part of Bay Networks), Synernetics and Advanced Micro Devices. Mr. Williams holds a BS with University Honors in Electrical Engineering from Carnegie Mellon and an MBA from Harvard Business School.

NERC CIP-014-1

NERC CIP-014-1 identifies a process for utility transmission stations and substations and their associated primary control centers, to assess and incorporate physical security risk management measures into critical locations that could compromise the backbone of the utility infrastructure. Its purpose is to identify and reduce the risk of critical power utility locations from physical attacks that could render them as inoperable or damaged. This could result in additional problems including power instability, uncontrolled separation or cascading within an interconnection.

NERC has identified communications as one of the key building blocks essential for physical security. A communication system must aggregate security monitoring data, alerts, video and data information from multiple physical security devices. It must also provide high reliability and resiliency. Modern wireless broadband communication networks as described here meet these requirements.

Guest Editorial

Electric Utility Restructuring: Better or Worse?

By Eric L. Prentis

Introduction

The economic theory of 'free market' competition naturally achieving lower electricity prices in restructured electric utility states is empirically tested in restructured states, pre-and-post restructuring, relative to U.S. electricity prices. Whether electricity consumers are better or worse off – as a result of electric utility restructuring – is answered here.

The vertically-integrated government-regulated natural monopoly electric utility model worked well in the U.S. – for nearly 100 years. However, some governors and state legislatures wish to reduce their states' electricity prices and are advised that electricity prices would naturally fall if 'free market' competitive marketplaces were established.

Consequently, beginning in the late 1990s, a limited number of states restructure their vertically-integrated government-regulated natural monopoly electric utilities – by instituting "free market" competition in the electricity generation and retail sales' sectors – while maintaining the middle-two sectors of transmission and distribution as a government-regulated natural monopoly.

Data and Method

U.S. Energy Information Administration (EIA) is the source of electric power price data for this study, from 1970-through-2011, both for the restructured electric utility states and for the U.S. electrical power system.

EIA identifies 15 states, plus the District of Columbia (D.C.), that are in different stages of restructuring their electricity markets – and explains that "restructuring means that a monopoly system of electric utilities has been replaced with competing sellers," and also states that 'restructured states' may be referred to as 'deregulated states.' Illinois, Ohio, Michigan and Pennsylvania severely limit their electricity market restructuring during this 1970-2011 study period, and consequently, are not included in states that have effectively restructured their electricity markets.

The 11 states and the D.C. that effectively restructure their vertically-integrated government-regulated natural monopoly electric utilities, and offer 'free market' competitive marketplaces – and the year their electric utility industry is effectively restructured – are listed in Table 1.

Table 1: Eleven States and the D.C. Offering Consumers 'Free Markets' and Effective Year Restructured

Eleven Electricity "Free Market" Competitive States and D.C.	Year Electricity Utility Industry Is Effectively Restructured
Connecticut	2000
Delaware	2000
Maine	2000
Maryland	2008
Massachusetts	1998
New Hampshire	2003
New Jersey	2003
New York	2002
Oregon	2002
Rhode Island	1998
Texas	2002
District of Columbia (D.C.)	2001

Means testing is used to statistically analyze electricity prices, from 1970 to 2011, for states that restructure their electric utilities – pre-and-post restructuring – relative to U.S. electricity prices; thus determining whether restructured electricity utility states are more or less efficient, after restructuring, than before.

Results

United States electricity prices increased 4.0 percent a year, from 1970 through 2011, denoted by its linear least squares trend line. During the same time, electricity prices for the 11 effectively restructured states and the D.C.'s mean increase is 8.9 percent a year, as shown in Table 2, by state. The effectively restructured 11 states and D.C. (restructured states) electricity prices rose about 220 percent faster than U.S. electricity prices, from 1970 to 2011.

U.S. electricity prices and electricity prices in each of the restructured states change yearly. To discover when electricity prices are rising fastest in the restructured states, relative price changes are computed. U.S. electricity prices are subtracted from the electricity prices in each of the restructured states, for each year, from 1970 through 2011. By comparing relative electricity price sample means for the U.S. and the restructured states, pre-and-post restructuring for each state, it is determined if electricity prices in the restructured states are increasing significantly faster after restructuring, than before restructuring, relative to U.S. electricity prices.

One-way ANOVA p-values – testing between group means for each 'free market' competitive state's regulated vs. restructured data sets – and Levene's, Welch, Brown-Forsyth and Mann-Whitney U tests' significance levels are shown, where required, in Table 2.

Table 2: One-way ANOVA—Testing Between Group Means for Each 'Free Market' Competitive State

Eleven Electricity Competitive. States and D.C.	Electricity Price Increases: 1970-2011	One-Way ANOVA P-values	Levene's Test	Welch Test	Brown-Forsyth Test	Mann-Whitney U Test
Connecticut	4.1%	.881ns				
Delaware	6.2%	.000***	.328ns			
Maine	13.1%	.000***	.090ns			
Maryland	3.2%	.659ns				
Massachusetts	7.9%	.000***	.006**	.001**	.001**	.000***
New Hampshire	3.1%	.445ns				
New Jersey	2.8%	.683ns				
New York	6.0%	.000***	.065ns			
Oregon	9.9%	.000***	.798ns			
Rhode Island	14.1%	.000***	.000***	.000***	.000***	.000***
Texas	6.5%	.000***	.002**	.005**	.005**	.003**
District of Columbia (D.C.)	29.9%	.000***	.000***	.000***	.000***	.000***

Levene, Welch, Brown-Forsyth and Mann-Whitney U test significance levels are shown, where required.
***** extremely significant at $p < .001$; ** very significant at $p < .01$;**
*** significant at $p < .05$; ns - not significant at $p \geq .05$**
Levene's tests for Delaware, Maine, New York and Oregon are not significant; therefore, no difference between population variances is assumed, and no further statistical tests are required.

Of the 11 states and the District of Columbia (D.C.) that have effectively restructured their electricity markets and allow 'free market' competition, electricity prices have gone up over four times faster, after restructuring than before restructuring, relative to U.S. electricity prices. Delaware, Maine, New York, Oregon, Rhode Island and the D.C. have extremely significant electricity price increases and are extremely less efficient, after their electric utilities restructure.

Massachusetts and Texas have very significant electricity price increases and are very less efficient, after their electric utilities restructure. Connecticut, Maryland, New Hampshire and New Jersey have no significant relative price increases, pre-and-post restructuring; however, these four states retain substantial price-suppression regulation, through re-regulation of their electricity marketplaces. No effectively restructured electric utility state is statistically more efficient.

The relative electricity price mean values for each 'free market' competitive state, pre-and-post restructuring, are listed in Table 3.

Table 3: Relative Electricity Price Mean Values for Each 'Free Market' Competitive State

Eleven Electricity "Free Market" Competitive States and D.C.	Regulated (R) and Restructured (D) Relative Electricity Price Mean Values
Connecticut	0.2157 (R) 0.2325 (D)
Delaware	0.6437 (R) 1.2658 (D)
Maine	0.4377 (R) 3.2142 (D)
Maryland	-0.0545 (R) 0.0050 (D)
Massachusetts	0.7604 (R) 1.7457 (D)
New Hampshire	0.2400 (R) 0.3744 (D)
New Jersey	0.2433 (R) 0.1867 (D)
New York	0.6669 (R) 1.3640 (D)
Oregon	-0.1056 (R) 1.8340 (D)
Rhode Island	1.2764 (R) 4.0036 (D)
Texas	0.1938 (R) 0.7970 (D)
District of Columbia (D.C.)	1.4539 (R) 9.5418 (D)

The relative electric power price means for restructured states, prior to restructuring, totals 5.9717, and after electric utility restructuring is 24.5647. Relative to U.S. electricity prices, from 1970 to 2011, the restructured 'free market' competitive states have electricity prices, during their restructuring periods, increase over four times faster than increases in electricity prices prior to their restructurings. Extremely significant and very significantly higher relative electricity prices, evident after electric utility restructurings in eight restructured states, are an increased burden on electricity customers—placing these eight restructured states at a competitive disadvantage when attracting new jobs and industries.

Conclusions and Policy Implications

The economic theory of 'free market' competition naturally achieving lower electricity prices in restructured electric utility states is empirically tested. U.S. Energy Information Administration (EIA) is the source of electric power price data for this study, from 1970 through 2011, which are analyzed using one-way ANOVA means testing for electric utility restructured states, pre-and-post restructuring, relative to U.S. electricity prices.

The results presented do not support the economic theory that 'free market' competitive marketplaces naturally achieve lower prices, in the electric power industry. Instead, electric company operating efficiencies are extremely and very significantly reduced in many restructured states, making society poorer.

'Free market' economic theory is not being appropriately applied to electric utility restructuring. Unique technical and organizational limitations may be the reasons. Empirical evidence does not support the energy policy of additional states restructuring their electric utilities, using the existing market design. What is important is developing and implementing an appropriate economic policy that realistically assesses the unique organizational and technical limitations in the vertically-integrated government-regulated natural monopoly electric power industry.

This article draws from Eric L. Prentis' 2015 International Journal of Energy Economics and Policy publication, entitled, "Evidence on U.S. Electricity Prices: Regulated Utility vs. Restructured States."

ABOUT THE AUTHOR

Eric L. Prentis, Ph.D., is a Registered Professional Engineer (I) with ten years of industry project management experience: including eight years in the engineering, design, construction and start-up of nuclear power plants, and two years on petrochemical plants. Dr. Prentis teaches in the MBA program at the University of St. Thomas, Houston, TX.

ADVERTISERS INDEX


Is there a business case for self-healing grids?