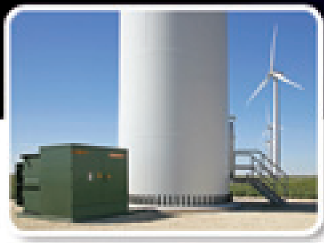
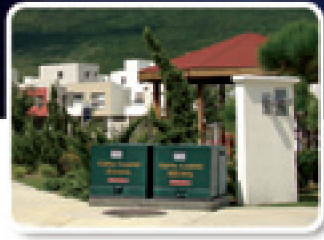
www.electricenergyonline.com

Electric Energy T&D MAGAZINE

JANUARY-FEBRUARY 2015 Issue 1 • Volume 19

The Rise and Fall of Transmission Investment





Electric Energy T&D
MAGAZINE

Publisher:
Steven Desrochers:
steven@electricenergyonline.com

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

Account Executives:
Eva Nemeth: eva@electricenergyonline.com

Art Designers:
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.
1160 Levis, Suite 100,
Terrebonne, QC Canada J6W 5S6
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

8 Industry News
44 Advertisers Index

Cover photo by CTC Global
Cover for the supplement by Toshiba Global Smart Community

4 POWER POINTS
Bentley Experienced
This past November, I travelled to London, England to partake of Bentley Systems' 'Year in Infrastructure 2014' Conference. It was an extremely enjoyable, mind-bending, time.

16 THE GRID TRANSFORMATION FORUM: Rise and Fall of Transmission Investment
With a recent surge in transmission investment, we ask Dave Bryant, Director of Technology at CTC Global to share his view on the drivers, challenges, and technologies associated with new transmission projects.

18 GREEN OVATIONS
The New Smart Meters
It's an exciting and challenging time for energy providers. In the past, utilities were often hesitant to adopt new technologies, but today we see the term 'innovation' used widely in discussions about electric utilities.

20 FROM RESEARCH TO ACTION
How to Navigate Existing Cyber Security Risk Management Guidance
Currently, the nation's power system consists of both legacy and next generation technologies. This increased digital functionality provides a larger attack surface for any potential adversaries, such as nation-states, terrorists, malicious contractors, and disgruntled employees.

24 Strategies for Successful Storm Response and Management
It's a beautiful day in your service area, and your distribution operations control center has few to no outages for operations to deal with; everything at your utility is status quo.

29 The Detroit Power Outage
The Detroit Power Outage brought eight hours of hardship to Detroit on December 2 -- hardship that could have been averted with microgrids.

31 Giving Marketing the Energy to Succeed
Energy and utility marketers are a unique breed facing the remaining vestiges of a conservative and cautious market with an influx of technology that is bringing change at an ever increasing pace.

34 BIGGER PICTURE
Keeping up with the Cloud
The rapid growth of hardware investments in smart grid opens up a new opportunity for utilities to take advantage of next-generation information technology, such as cloud computing, to fully unlock the insights and value that a modern grid has to offer.

37 SECURITY SESSIONS
Modbus and GETAC and Conitel. Oh my!!
Serial communications have been used in industrial automation for many decades, particularly starting in the early 1960s with the invention of integrated circuits and accelerating when (relatively) low-cost 16-bit 'minicomputers' with RS-232 communication boards became available.

40 GUEST EDITORIAL
San Bernard Electric Installs Advanced Data Exchange Part II
In an earlier edition of EET&D (November-December 2014), we looked at San Bernard Electric Cooperative's (SBEC's) installation of MultiSpeak specification including a metering system, an outage management system (OMS), a customer information system (CIS), and a geographic information system (GIS).

SUPPLEMENT

2 Is Inserting Renewables into the Electric Grid Stable?
In a time driven by the adoption of renewable energy resources, we're also experiencing new challenges with the way that power is supplied.

4 Facing the New Energy Future
Today's utilities are facing a lot of uncertainty about the future direction of their business and industry.
Will energy be more democratized, with advanced distributed energy resources such as solar panels changing how electricity is sourced?

8 Out of the Box Thinking for Home Energy Management
Not so long ago, setting up a new computer was a hassle. Thankfully, technology companies have largely remedied this complexity, and customers now expect products, from smart phones to computers, to work right out of the box.

9 Transformer Truth or Dare
Owning a transformer means making many big-money decisions, but those decisions aren't always clear or straightforward.

Bentley Experienced

This past November, I travelled to London, England to partake of Bentley Systems' 'Year in Infrastructure 2014' Conference. It was an extremely enjoyable, mind-bending, time.

The conference was a global gathering of executives and thought leaders in the world of infrastructure. Early on day one, after an in-depth presentation to over 120 media-types from all over the world, I prepared for the next three very full days. Leaders in the industry engaged in interactive sessions that explored the coming together of technology and business drivers with the view to seeing what technologies and next, best practices will shape the future of infrastructure delivery.

Throughout the time, industry-specific forums were presented comprising keynote addresses from industry experts. One of the cornerstones of the event was the Be Inspired presentations and awards, which showcased 54 real-world projects from across the globe.

The forums were of prime importance to me as a journalist and, in particular, the one that encompassed utilities. They covered topics of relevance to all types of utilities including the impact of cloud technology on utility workflows, new technologies to help meet the challenges of subsurface utilities, best practices in engineering collaboration, and how to achieve operational excellence through better-performing assets.

The other forums broke down as follows:
Building: Engaged building professionals in a broad range of presentations including business requirements for Building Information Modelling (BIM), the benefits of multi-discipline design collaboration and knowledge sharing, and innovations in construction management.

Rail and Road: Focused on improving productivity, increasing efficiencies, reducing risks, and adding value. It also covered the industry's best and next practices and highlighted new technologies being used in the industry.

Oil, Gas, Chemical, and Mining: Designed for executives who wish to explore new methods and techniques improve project and asset performance on new capital projects and ongoing operations.

EPC and A/E: Addressed topics pertaining to the entire project lifecycle and the impact of cloud and mobile technology. The audience heard from industry leaders from world-class organizations on how they are using the latest innovations and technologies that result in improved project delivery and better-performing projects.

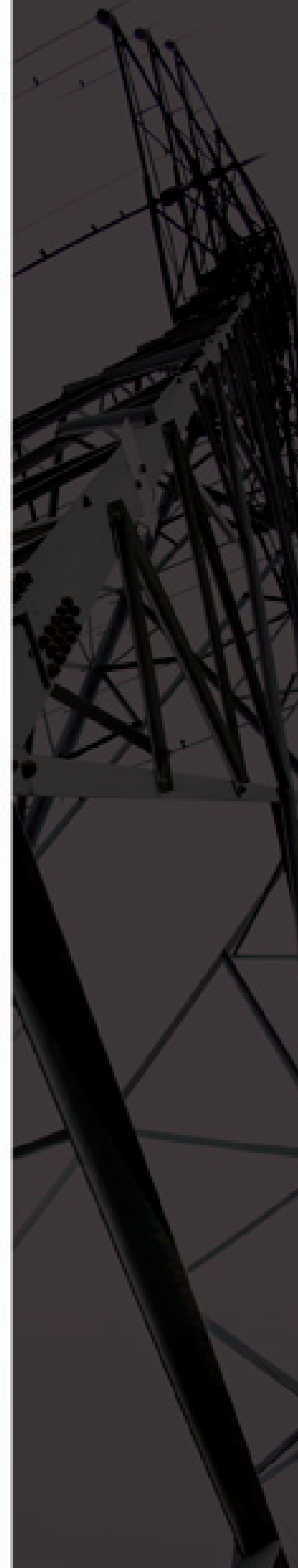
Visions for the Future – Presented by Bentley Fellows: Opportunities for improving construction productivity and sharing data between BIM and SIM (Society for Information Management) were discussed in detail. The presentations also covered deep intelligent analytics, augmented and virtual reality, new 3D capture methods, and focus devices for hybrid datasets.

The first night saw all of the visiting journalists on board a cement-hulled river barge that had been converted to a four-star floating restaurant. We travelled the Thames admiring the sights along the river for several hours. There was a live band on board and we enjoyed good food and great conversation with the Bentley folks. The group travelled to and from the river in three vintage 'London Buses,' a nice trip down memory lane.

The next night I, and a contingent of about 40 other journalists, were treated to a most enjoyable Lebanese meal at one the restaurants near the hotel. Sitting amongst journalists from across the globe was a particular treat and the opportunity to share in their knowledge was quite refreshing.

It was raining when we left the eatery and one would think that I'd know better but I came within a few centimetres of getting knocked down by a London cabbie racing around the corner. Living in Britain and visiting so many times and knowing from experience that I didn't want to end up in their health-care system, I should have remembered the pedestrian's cardinal rule – if you step off the pavement (the British term for sidewalk) against a light or outside of a Zebra crossing, you are fair game for motorists. You might as well paint a Day-Glo bull's-eye on yourself if you insist on taking such risks.

POWER POINTS



I was late getting to one of the lunches after our utilities session ran overtime. The lunch was a large affair with dozens of tables filling one of the grand ballrooms of the hotel. The Be Inspired finalists were also at this lunch so seating was a real premium. I noticed a lone seat at a table that had seven or eight people already seated. When I sat down the conversation that was buzzing around the table came to an abrupt silence.

At that point, a young lady turned the description card around to indicate this table was for the Russian delegates only. I put on my best toothy grin and nodded my head as a friendly gesture and they invited me to stay. Soon, Boris, Natasha, Igor, Alexei, et al were nattering back and forth to each other in their native tongue. My meal was broken up by smiling at them as if I understood their lingo and by throwing in a few 'das' and 'nyets'. Finally, as I stood to leave, one man sitting across from me had noticed my name tag indicated press and he politely asked, "You go now and make press release about Russians?" I immediately replied, "Sure, I'll just go to my room and brush up on your language." We all laughed somewhat knowingly and in a friendly manner and I left, having enjoyed another experience at the conference.

Throughout the conference, finalists in the Be Inspired competition presented to the attendees. I spoke with a few members of this brain trust and was absolutely blown away by the level of innovation, originality, and timeliness of their projects. Of particular note were undertakings like:

- Tenaga Nasional Berhad – Asset performance management at Tenaga National Berhad Power Plants
- Guangdong Hydropower Planning & Design Institute – 3D Design for Qinqyuan Pumped Storage Power Station – Detailed design and construction
- Hitachi-GE Nuclear Energy, Ltd. – Development of decommissioning engineering platform based on plant 3D model
- I.Y. Genesis Advanced Engineering Ltd. – Bobo II-III 54 MW power plant
- Kavin Engineering and Services Private Limited – Power plant for Garraf Development Facility Operation

Over the course of the next few days, I attended utility and energy-related presentations including:

- Enterprise GIS strategy for increased revenue and lower costs using Bentley's Communications Solution
- Bentley substation implementation and integration into ElectraNet SOP
- Zhaotong converter station
- Technology trends and the value-conscious utility
- New technologies for meeting the challenge in subsurface utilities
- Mission critical geospatial technology in utilities
- Best practices in multi-disciplinary collaboration in engineering
- Designing and operating better performing substations
- Achieving operational excellence through better performing assets
- Utilities of the future: Postcards from the edge

Each presentation room was equipped with full wireless AV and every presenter was totally engaging. Unlike many presentations I've sat through, Bentley insisted there was always enough time for a Q&A. It's amazing how much valuable material can come to the surface 'after the fact.'

I also learned that the phrase 'Big Data' has this year been replaced by 'The Internet of Things,' (IoT) a Microsoft-coined term taking us into the future. Using this technology, companies and enterprises need to consider the following:

- Where is your business going?
- How are you going to make it thrive?
- How will you make the most of what you have, and incorporate today's and tomorrow's technology breakthroughs to ensure your business is set up for the long term?
- How are you going to help your employees become more efficient?
- How are you going to reduce costs yet improve customer service?

The answers to these questions – and many more – likely already exist in any enterprise with the data and systems already in place. Ideas, innovation, and technology partners may be needed to help stop running the business and start making it thrive.

During the last evening, the awards dinner for the Be Inspired finalists was held. Again, my chin dropped a mile at the world class quality, inventiveness, ingenuity, technology, and thought processes of those who received awards. If the ones I met were any indication of achievement, however, there wasn't a single loser in the room. My hat comes off the Bentley for giving such bright minds the opportunity to really shine.

New technology can at once be exciting and challenging to assess from a business perspective. The IoT is an amazing trend. It provides vast opportunities, but can also present a challenge. It often seems overwhelming, complicated, and expensive. What is needed is to look beyond the hype and start on a path that will unlock the potential of the Internet of Your Things. Real, transformative results in an organization await. Apparently, it's easier than is thought.

I had to scramble to get to the airport on time following the last Utility Forum. Another British Airways Triple Seven winging its way across the Atlantic. It was there and I was there and now here I am all the wiser. The Bentley experience will stay with me and feed my mind for a long time to come.

INDUSTRY NEWS INDUSTRY NEWS INDUSTRY NEWS

Secretary Moniz Announces $125 Million OPEN Solicitation for Transformational Energy Projects

ARPA-E Issues OPEN Funding Opportunity Announcement to Support Disruptive New Energy Technologies

January 2015

U.S. Energy Secretary Ernest Moniz announced that the Department of Energy's Advanced Research Projects Agency - Energy (ARPA-E) is issuing its third open funding opportunity announcement, OPEN 2015, for up to $125 million. OPEN 2015 will support energy research and development projects from America's top innovators for disruptive new technologies in transportation and stationary applications.

"OPEN 2015 highlights ARPA-E's commitment to transformational energy innovations," said U.S. Energy Secretary Ernest Moniz. "We are excited to announce this open solicitation to support the development of a broad range of disruptive technologies, advancing our all-of-the-above energy strategy to ensure a secure, affordable and sustainable American energy future."

ARPA-E has issued previous OPEN solicitations in 2009 and 2012. Open solicitations ensure that ARPA-E can support transformational projects outside the scope of existing ARPA-E focused programs. The projects selected under OPEN 2015 will pursue novel approaches to energy innovation across the full spectrum of energy applications.

For more information on OPEN 2015, please visit: http://bit.ly/OPEN2015

Satisfaction Improves for More than 80 Percent of Utilities for Second Consecutive Year

January 2015

Business customer satisfaction with their electric utility has hit its highest mark since 2009, based primarily on a substantial year-over-year increase in satisfaction with power quality and reliability, which, in turn, is driven by a significant improvement in utilities' efforts to provide more accurate outage information, according to the J.D. Power 2015 Electric Utility Business Customer Satisfaction StudySM released today (1/14).

The study measures satisfaction among business customers of 101 U.S. electric utilities, each of which serves more than 25,000 business customers. In aggregate, these utilities provide electricity to more than 12 million customers. Overall satisfaction is examined across six factors (listed in order of importance): power quality and reliability; billing and payment; corporate citizenship; price; communications; and customer service. Satisfaction is calculated on a 1,000-point scale.

Reaching its highest score in the past seven years, overall satisfaction among electric utility business customers is 677 in 2015, compared with 617 in 2009 a significant 60-point increase. Additionally, satisfaction increases by 15 points from 2014 (662). Performance improvement in 2015 is driven by a sharp year-over-year rise in satisfaction with power quality and reliability (+19 points), which is bolstered by a notable improvement in utilities' efforts to provide more accurate information about outages.

In addition, this is the second consecutive year of improvement for more than 80 percent of the electric utilities included in the study, regardless of whether they rank among the highest- or lowest-performing companies.

"It's important to note that many electric utilities that have traditionally ranked at the low end of the overall index now include in their business goals initiatives that are aimed at improving customer satisfaction," said Andrew Heath, director of the energy practice at J.D. Power. "Among those utilities, several are posting substantial increases in satisfaction as a result. When utilities highly satisfy its customer base, there is a quantifiable positive impact on profitability and credit ratings for the utility."

KEY FINDINGS

- Power quality and reliability satisfaction among business customers who receive outage information (713) is 143 points higher than among those who do not receive such outage information (570).
- Utility communications positively impact satisfaction. Overall communications satisfaction among customers who recall receiving a communication from their utility is 74 points higher than among those who do not recall any communication. The percentage of business customers recalling a communication from their utility has increased to 55 percent in 2015 from 51 percent in 2014.
- Online account setup among business customers has grown to 57 percent in 2015 from 33 percent in 2009. Nearly three-fourths (72%) of business customers resolve their problem or issue online during the first contact, compared with 69 percent of those who resolve their problem by phone during the first contact.
- Overall satisfaction is highest among industrial business customers (682) and lowest among healthcare customers (675).

FLEXIBLE

RIGID

A SERVICE WEDGE THAT MAKES AN ENTRANCE

EASY INSTALLATION AND YOUR CHOICE OF BALL DESIGN

For deadending and stress relief of drop installations, look no further than the Fargo® Service Entrance Wedge Deadend. Fast and easy to install, our design allows for easy sag adjustments and is available in rigid or flexible bail designs.

For more information visit hubbellpowersystems.com/literature/connectors/SF05027E_ServiceWedge.pdf

AD_05_042_E

HUBBELL® Power Systems, Inc.

ENDURING PRODUCTS & PEOPLE
YOU CAN DEPEND ON
hubbellpowersystems.com

ATC awards $55,000 to communities for vegetation plantings

Program continues to support beautification efforts, electric reliability

January 2015

American Transmission Co. has awarded $55,000 to 33 communities in its service area to plant trees and other vegetation. The Community Planting Program, now in its second year, supports the reliability of the electric transmission system and helps to beautify communities by promoting plantings located outside of transmission line rights-of-way.

"It's ATC's responsibility to keep trees and brush out of the transmission line rights-of-way for public safety and electric system reliability," said ATC Environmental and Local Relations Manager Greg Levesque. "Collaborating with communities in our service territory to educate them about vegetation growth in the rights-of-way helps ATC maintain the safety and electric reliability of the grid."

Municipalities and counties received funding ranging from $500 to $4,000 for planting projects on public property where ATC facilities exist. To qualify, community recipients committed to complying with ATC's maintenance standards for all current and future planting plans and urban forestry activities near high-voltage electric transmission lines.

The Community Planting Program is part of ATC's Grow Smart initiative - a program that promotes planting native, low-growing vegetation near transmission line rights-of-way. Trees and other vegetation purchased by communities through the Community Planting Program reinforces this initiative by encouraging the planting of tall-growing trees and other vegetation outside the transmission line rights-of-way.

Hydro One Receives Prestigious Sustainable Electricity Company Designation

January 2015

The Canadian Electricity Association (CEA) announced that it has designated Hydro One Networks Inc. ("Hydro One") a Sustainable Electricity Company for its commitment to sustainable business practices.

Hydro One, only the fourth electricity company to receive this designation, is the largest electricity transmission and distribution company in Ontario, with $21.6 billion in total assets.

The Sustainable Electricity Company designation, established by CEA for utilities across Canada, acknowledges success against the three foundational pillars of sustainability - environmental, social and economic performance. It requires utilities to establish an Environmental Management System consistent with the ISO 14001 standard and meet the actions and expectations under the ISO 26000 Guidance on Social Responsibility. As part of the designation process, applicants must also pass a third-party verification to ensure adherence to the brand criteria and take further corrective actions where warranted.

"This designation is a reflection of Hydro One's unwavering commitment to integrating sustainable business practices into its operations and activities," said Jim R. Burpee, President and CEO of the Canadian Electricity Association. "Addressing sustainability challenges is critical in today's dynamic energy environment, and I applaud the achievements of Hydro One management and staff."

"We are proud to receive this designation from the Canadian Electricity Association," said Carmine Marcello, President and CEO of Hydro One. "It recognizes the outstanding job our employees do in delivering electricity in a socially responsible and sustainable manner and in meeting the high expectations of our customers and the people of Ontario."

"Canada's electricity sector is at a critical stage in its history, requiring continued innovation and adaptation," said Mike Harcourt, 30th Premier of British Columbia and the current Chair of the CEA Public Advisory Panel. "Hydro One exemplifies the sector's commitment to sustainable business practices and corporate responsibility. I look forward to seeing more utilities achieving this designation in 2015."

For more information about the Sustainable Electricity Company designation, please visit: www.SustainableElectricityCompany.ca.

Industry Tests Confirm Sensus Gen 3 Electric Meters Comply with Safety Standards

SaskPower and The City of Medicine Hat release results from Underwriters Laboratories

January 2015

Independent tests performed by Underwriters Laboratories (UL) at the request of two Sensus customers have confirmed that the Sensus Generation 3 iCon A 2S remote disconnect electric meter is in compliance with its latest safety standards. UL is a leading organization for testing, certifying and validating electric meters.

In a news release by SaskPower issued December 17, the utility wrote that the meters "were subjected to the performance requirements in the newest industry standard, the UL 2735 Standard for Safety for Electric Meters, and the meters were found to comply."

The City of Medicine Hat asked UL to perform different performance and safety tests on 40 Sensus meters. The tests included nine UL 2735 ANSI (American National Standards Institute) tests and nine UL 2735 tests. The utility also asked UL to conduct specialized tests for dust and water penetration, damp heat and extended overvoltage. In a December 18 news release, the city wrote that "as a result of the positive test results, the Energy Committee today recommended continuing with electric automated metering installations using the Sensus Generation 3 iConA metering products." City council approved the recommendation and the utility plans to install the remaining meters beginning this week.

"Safety and customer satisfaction remain our top priorities," said President Randy Bays. "We recognize that the industry has concerns about the performance of electric meters and we are taking a leadership position in developing solutions that address the issues."

Last August, Sensus launched its new iConA Generation 4 residential electric meter that helps electric utilities and municipalities better collect and analyze data.

Consumers Energy Selects Accenture to Deploy New Ventyx Digital Platform to Help Improve Field Worker Safety, Productivity and Customer Experience

January 2015

Accenture (NYSE:ACN) has been selected by Consumers Energy (NYSE:CMS), Michigan's largest utility, to deploy new mobile workforce management (MWFM) software from Ventyx, an ABB company, to help field workers improve safety, productivity and customer experience.

Accenture will work with Consumers Energy and Ventyx to implement the latest release of Service Suite with optimized, automated dispatching, for schedulers, dispatchers, field crews and supervisors. This will replace Consumers Energy's legacy mobile workforce management system, providing efficiency improvements with real-time work status, integrated scheduling and appointments, field data collection and reporting with real-time views of parts, people and other resources.

As a result of these efforts, Consumers Energy field supervisors will have new digital tools, ranging from pinpointing crews on maps to more easily verifying timesheets, with unprecedented access to their teams' workload and status. This project is part of a broader program within Consumers Energy called Field Mobility which supports Consumers Energy's overall vision to become their customers' trusted energy partner.

"Our goal in implementing this new technology is to further minimize field workers' delays in receiving and using accurate and timely information for making service calls, especially during storms and other interruptions," said Michele Kirkland, Vice President of energy operations, Consumers Energy. "Replacing the legacy systems with a new digital platform will provide us with a comprehensive view of our field operations with relevant, real-time information to improve the accuracy of scheduling customer appointments and to increase productivity and efficiency by assigning them to the most optimal crews to minimize travel times."

Accenture was selected to be the systems integrator for this project, based on its proven track record in smart grid services and in the areas of work, field and resource management. In addition, Accenture will work closely with the project team to provide system testing, change management and training development to Consumers Energy.

"The increasing frequency of adverse weather events and the rise of renewables are putting more stress on an aging grid, which means that effective and safe outage response and service maintenance is more critical than ever," said Bill Ernzen, managing director in Accenture's utilities Smart Grid Services business. "This new digital platform will allow Consumers Energy to provide a more timely and accurate service to its customers, while better ensuring the safety of its field crews. It will also enable field leaders, using new tools and processes, to spend more time in the field coaching and supervising crews."

"As one of the largest utilities in the U.S., Consumers Energy has proven its dedication to quality and performance by committing to invest billions of dollars in Michigan over the next five years," said Ventyx Global Product Group Manager Matthias Heilmann. "Choosing to earmark part of this investment for implementation of the latest Ventyx Service Suite solution - used by more than 100,000 mobile technicians and their dispatchers every day - further proves their dedication to customer service is equally as strong."

Horizon Utilities to upgrade aging electricity infrastructure using rate increase

January 2015

The Ontario Energy Board (OEB) recently approved a Horizon Utilities rate increase to allow for critical reinvestments in its electrical distribution system infrastructure across Hamilton and St. Catharines.

Horizon Utilities filed a rate application (the "Application") with the OEB for 2015-2019 in order to finance renewal investments in infrastructure, technology and other initiatives in support of delivering a high level of customer service and a safe reliable supply of electricity. Horizon Utilities' distribution charges increased effective January 1, 2015.

Many assets throughout Horizon Utilities' system in St. Catharines and Hamilton are facing significant pressures due to increased customer demand and a growing number of system components nearing or at end of life which require replacement.

The average residential customer using 800 kWh of electricity per month can expect an increase of $1.44 per month on the distribution portion of their bill. On the total bill, this represents an increase of 1.96%. Over the five years of the Application timeframe, a typical residential customer can expect an average annual increase of 2.43% on the distribution portion of their bill.

As part of the Application, Horizon Utilities developed a sustainable, forward-thinking Distribution System Plan that will modernize, expand and maintain the distribution system, to avoid risking system failure. The plan strikes a balance between managing customer rate impacts with investment objectives while factoring in cost-effectiveness, reliability, priority sequence and environmental considerations.

"At Horizon Utilities, our mandate is the delivery of safe and reliable electricity and customer service excellence to the communities we serve," said Max Cananzi, President & CEO of Horizon Utilities. "In order to continue in our proud history as a dependable electricity provider, we must make the necessary investments to modernize, maintain and expand our distribution system."

With a continued commitment to assisting customers in managing their electricity bills, information on conservation and demand management programs, as well as other helpful tips, can be found at www.horizonutilities.com

California roadmap paves the way for energy storage technology

January 2015

The California Independent System Operator (ISO), the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) unveiled a comprehensive roadmap to assess the current market environment and regulatory policies for connecting new energy storage technology to the state's power grid.

Storage technology is being hailed globally as the game-changer toward reliably managing low-carbon, greener electricity grids. California, a national leader in advancing energy storage, envisions this technology as a critical component in reducing global warming, improving air quality and promoting energy independence. The state currently has several pilot projects, and is working toward commercialization of energy storage.

"Advancing and Maximizing the Value of Energy Storage Technology - A California Roadmap," which can be found on the ISO website, is the product of collaboration by the three organizations and input from more than 400 interested parties, including utilities, technology companies, generators and environmental groups.

"The roadmap is a foundation to integrate energy storage technologies that benefits grid reliability and consumers throughout the West," said ISO CEO Steve Berberich. "This document details specific actions needed to optimize this maturing technology."

California already established itself as an early advocate of energy storage technology when in 2013, the state mandated that investor-owned utilities reach a combined target of 1,325 megawatts of energy storage to be online by 2024.

"California has a number of policies and programs related to energy storage, and collaboration among the ISO, the Energy Commission and CPUC is essential as we move forward with large-scale energy storage procurement," said CPUC Commissioner Carla Peterman. "The roadmap represents an important interagency effort informing our next steps in meeting the 1.3 GW target and our broader energy goals."

"As we aim to further reduce greenhouse gas emissions and by 2030 get 50 percent of our electricity from renewable sources, flexible resources like storage will be important to balance the electric system," said Energy Commission Chair Robert B. Weisenmiller. "The collaborative effort of this roadmap will help by identifying barriers to energy storage technologies so we can keep our electricity supplies safe, affordable and reliable."

The state has seen explosive growth in sustainable and renewable energy sources, particularly with solar rooftop installations more than doubling in recent years. But power from renewable sources, such as solar and wind power plants, is intermittent and its generation often doesn't conform to the instantaneous nature of electricity demand. Overgeneration - or too much generation at times when demand is low - creates instability in the marketplace and forces renewable energy to be underused.

One of the challenges of electricity for a large-scale grid is that the energy has to be used virtually at the instant it's generated. Since the discovery of electricity, inventors have looked for ways to store energy for use on demand. Technology to store energy is vital to optimizing the grid, increasing renewable energy sources and reducing greenhouse gas emissions.

Some of the technology being tested and marketed are batteries, flywheels, compressed air, thermal and pumped hydropower. Several utilities have made substantial investments in storage projects, and have signed contracts and announced they are looking for future commercial potential.

The top concerns of industry stakeholders are implementing a process for promoting existing products and driving new ones to market; understanding and addressing connection of storage devices to the grid; and reducing costs and setting up fee structures for the new technology.

NYISO Restructures Leadership Team

President and CEO Stephen Whitley to Retire in 2016

January 2015

The New York Independent System Operator's (NYISO) Board of Directors announced the extension of President and Chief Executive Officer Stephen Whitley's contract through mid-2016 when he will retire, capping a remarkable 46-year career in the energy industry, including eight years as President and CEO of the NYISO. The Board also announced the promotion of two key leaders.

The NYISO is restructuring its leadership team to drive internal efficiencies, expand the scope of its key leaders and best position the company to meet the emerging challenges in the industry. The new structure will ensure the proper focus and leadership on key strategic initiatives and enhance the organization's ability to proactively address the significant challenges facing the energy industry, including the growing dependence on natural gas, increased penetration of renewable and distributed energy resources and the impact of new environmental regulations on the operations of existing generating units.

As part of the restructuring, Richard Dewey has been promoted from Senior Vice President and Chief Information Officer to Executive Vice President, with responsibility for operations, information technology and market structures. In addition, Thomas Rumsey has been promoted to Senior Vice President of External Affairs with responsibility for external affairs, media relations, corporate communications, government and regulatory affairs, stakeholder services and strategic planning.

Senior Vice President and Chief Operating Officer Rick Gonzales has been assigned the additional responsibilities of preparing the NYISO for the growing dependence on natural gas as well as the increasing penetration of renewable and distributed energy resources. Senior Vice President of Market Structures Rana Mukerji will be responsible for market design, demand response and system planning.

The NYISO Board of Directors will conduct a nationwide search for the CEO position and consider both internal and external candidates.


We are here.
MORGAN®
SCHAFFER

THE GRID TRANSFORMATION FORUM

Envisioning the 21st Century Grid

Rise and Fall of Transmission Investment

With a recent surge in transmission investment, we ask Dave Bryant, Director of Technology at CTC Global to share his view on the drivers, challenges, and technologies associated with new transmission projects.

EET&D: According to the US Energy Information Agency there has been a five-fold increase in transmission investment over the last decade or so in North America. What has driven this?

Bryant: Actually a number of things. Following World War II there was surge in generation and transmission investment to serve growing demand. In the late 1960's the infrastructure adequately supported demand and things stabilized. Transmission investment then declined until the late 1990's. The Western Energy Crisis of 2000 was a bit of a wake-up call, but it wasn't until the major east coast outage of 2003 that really captured everyone's attention.

EET&D: What happened as a result of the outage?

Bryant: It reminded us that our grid was substantially aged and vulnerable. The cascading outage was triggered by a series of events that started with inaccurate telemetry data, a race condition computer bug, a subsequent reboot failure and a lack of effective communication that led to a series of sag-trip outages on a number 345 and 138 kV lines. The economic impact was estimated at $8 to $10 billion which captured the attention of policy makers. The Energy Policy Act of 2005 in the US, for instance, was a significant call to action.

EET&D: In what way?

Bryant: For one, it strengthened the resolve of grid operators and utilities to improve their interaction and communications, but more importantly, it provided incentives (and loan guarantees) to inspire 'risk-adverse' utilities to leverage new technologies that could improve the 'efficiency, capacity and reliability of the grid.' This included new composite core conductors such as ACCC that were developed to increase grid capacity, reduce congestion costs and mitigate thermal sag that ultimately caused the major blackout of 2003.

EET&D: Can you explain grid congestion?

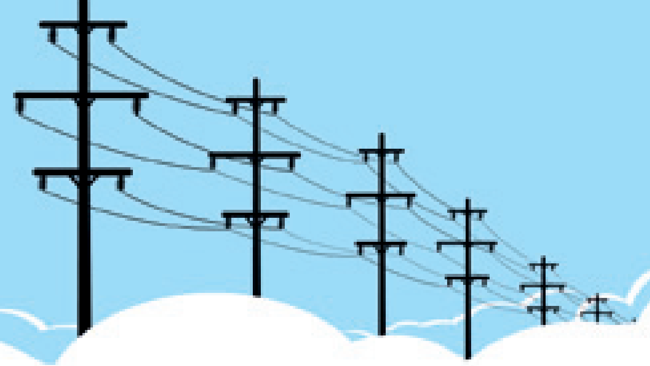
Bryant: Grid congestion is a situation that occurs when sections of the grid (usually the wires themselves) are not capable of carrying the required current. This generally occurs during warmer months when demand is high. The effect is that grid operators have to reroute power from alternate sources of generation that are typically more expensive. The impact can substantially increase the price of delivered power to the consumer. In recent years these costs have been measured in the billions of dollars annually. Fortunately entities such as the PJM Interconnect (and other RTO's and ISO's) and their associated utilities are targeting congested lines and upgrading them to substantially mitigate the problem.

EET&D: You mentioned composite core conductors. Can you elaborate?

Bryant: Composite core conductors were developed primarily to mitigate thermal sag due to the fact that their coefficient of thermal expansion (CTE) is less than that of a conventional steel reinforced conductor. In the early 1900's most bare overhead conductors were made with copper wire. During World War I, copper was diverted to the war effort and aluminum was subsequently used in its place. Because aluminum is relatively weak, steel core strands were incorporated in many conductor designs to enable greater spans between fewer structures. The composite core conductors take it a step further as they are stronger and lighter than steel. They also resist corrosion and fatigue better than steel, and, due to their lighter weight, they can incorporate more aluminum without a weight penalty. The added aluminum content not only serves to increase line capacity, it also reduces electrical resistance which reduces transmission line losses under any load condition.

THE GRID TRANSFORMATION FORUM

Envisioning the 21st Century Grid



EET&D: Transmission line losses in North America are relatively low. Is reducing them further that beneficial?

Bryant: Surprisingly yes. While the cost of line losses are typically passed through to the consumer, what many utilities are now realizing is that a reduction in line losses can essentially 'free-up' generation capacity that is otherwise wasted. This energy can then be sold. From another point of view, a reduction in line losses can reduce fuel consumption and associated emissions from non-renewable resources. While line losses in North America are a relatively low three to four percent, you'd be astonished at the impact a thirty percent reduction actually offers. In developing countries like India, technical losses are well over twenty percent and closer to thirty percent when you factor in commercial losses.

EET&D: Are the utilities focusing on line loss reductions in North America?

Bryant: Not typically as a first tier priority, however, a great deal of effort is being make to alleviate grid congestion, improve grid reliability and, in the wake of several super storms, improve grid resiliency, by 'hardening' the grid so that damage can be avoided or quickly repaired. While the benefits of these priorities are obvious, at the end of the day, the efficiency of the grid is also improving through these efforts. This is, in part, due to the fact that modern high-capacity low-sag conductors offer decreased electrical resistance. While they are typically installed to increase the capacity of existing transmission and distribution lines, their improved efficiency and ability to carry increased current also serves to reduce load levels on adjacent lines allowing them to operate cooler and more efficiently.

EET&D: Regarding 'first tier' priorities, what are some other reasons we are seeing an increase in T&D investment?

Bryant: In addition to activities focused on linking renewables, hardening the grid, and modifying lines found to be out of compliance due to excessive conductor sag, uncertainties associated with deregulation have dissipated and market improvements and regulatory clarifications are helping utilities better understand their potential returns on investment. With that said, securing permits to build new lines is still very challenging and most utilities and regulators have trouble recognizing, measuring and conveying the numerous but less obvious benefits of transmission investment that could ultimately reduce the burden.

EET&D: Can you explain?

Bryant: Generally a number of transmission projects are proposed or drafted to accommodate a variety of needs. While circumstances often change, projects are periodically evaluated and reprioritized. When priorities and economics are sorted, the 'green light' is given to projects that offer the greatest cost benefit ratio. Unfortunately, not all benefits are generally considered. For instance, if a new line is proposed to link a new source of generation, the project has obvious value. However, additional benefits might include improving grid reliability, reducing emissions and increasing market competition that could lead to reduced consumer prices, among many other societal benefits. Fortunately organizations such as EPRI, EEI, the Energy Future Coalition, WIRES, The Brattle Group, and several other entities are developing new methods to assess and analyze the true value of transmission investment.

EET&D: This sounds positive, but what are the utilities doing in the meantime?

Bryant: In the past, utilities spent billions of dollars improving the efficiency of generation to reduce operating costs and improve profitability. More recently they have supported improvements in efficiency of demand side appliances in an effort to minimize the need for additional generation investment. Lately, much effort has been directed at 'Smart Grid' strategies to carry this further. Today, utilities are also investing in modern conductors to improve grid efficiency, capacity and reliability. The ACCC conductor, for instance, has already been deployed to over 300 projects in 30 countries. This is a good thing for everyone because without access to affordable and reliable power no society can possibly flourish.

EET&D: We can't thank you enough Dave for spending some of your valuable time with us. Your in-depth explanations with a glimpse at the past and the view going forward regarding this important issue are a valuable lesson for our readers.

About the author

Dave Bryant, Director Technology, CTC Global was one of the original developers of the ACCC conductor and ancillary hardware components. His background in composite materials, testing and industrial design helped expedite the commercialization of the ACCC conductor.

GREEN OVATIONS

Innovations in Green Technologies

The New Smart Meters
A Key Player in Providing Reliable, High Quality Power

By Steve Kuperman

It's an exciting and challenging time for energy providers. In the past, utilities were often hesitant to adopt new technologies, but today we see the term 'innovation' used widely in discussions about electric utilities. The smart grid – and utilities that preside over the grid – faces much heavier demands from customers than they did even five years ago, which is forcing utilities to change and adapt. Mobile device charging, computers and tablets, wide-screen TVs, and now an ever-growing number of electric vehicles are all using more power than ever – and that's just on the residential side. Advances in industrial process are also increasing the demand on the grid. Customers are not just looking for more power, but for more reliable, cleaner, higher-quality power.

Utilities are responding to this demand by layering new technology into their infrastructure investments in order to improve the efficiency of their electric distribution systems and gain valuable energy insight. According to the Edison Foundation, which monitors innovation in the utility market, this includes a trend toward new distribution automation systems and advanced metering infrastructures capable of improving asset management and operational efficiencies at the grid level.

As utilities work to modernize the grid, the most noticeable upgrade has been the incremental installation of residential smart meters. Today in the U.S., there are over 40 million smart meters in use. While many of these have basic functionality like recording electricity use at pre-defined intervals and sending this data to the utility, others are more advanced with two-way communications that allow customers to monitor home energy use in near real-time. Whatever their capabilities, smart meters function as sensors at the grid's point of contact with customers, providing utilities with data they need to address problems on the grid as they happen.

These advanced utility meters are much more than the smart meters installed at residential sites. The meters are revenue-accurate, intelligent devices designed for use at key distribution points where they can monitor everything from generators and substations to industrial service entrances, 24 hours a day. Some meters, like the ION8650, have multi-port, multi-protocol communications capabilities and can perform sophisticated power quality analyses. The ION meters are also designed to work with Power Monitoring Expert software, creating a layer of intelligence over top of a utility's energy assets and integrating with diverse distribution automation systems.

Smart metering technology brings tremendous value to energy providers by maximizing metering accuracy at all intertie points, verifying compliance with power quality standards, and quickly analyzing and isolating the source of any power quality problems. For example, the ION8650 meters are able to analyze disturbance information to determine the direction of the disturbance relative to the meter and provide detailed results, complete with timestamp – using disturbance direction detection (DDD™).

DDD functionality can be particularly effective for utilities servicing more rural areas, who deal with unique circumstances not often faced by their urban counterparts. For example, most urban utility customers are less than five miles from the electrical supply. Any disturbance or damage is quickly located and repaired. In the open country, linemen looking to repair disturbances or outages regularly encounter terrain with no roads; they may even need to get out and walk the lines if conditions make driving impossible. This type of grid exposure (longer span lengths from the source of power and thus a greater disturbance or outage risk from weather events) is the major reason why it can take a longer time to address power disturbances in these areas. DDD metering technology greatly reduces the time spent locating these faults and resolving power issues.

One rural electric utility is using smart meters to provide stronger, more reliable power to their customers. The utility provides electric service across many counties and maintains nearly 10,000 miles of energized line – the utility has one of the largest service territories in the United States, which presents some interesting challenges.

Providing reliable and high quality power can mean a seven hour commute for maintenance crews each way – and that's just to check and service remote substations. When the utility's Technical Services department upgraded their electrical metering equipment as part of their infrastructure improvements, they chose ION revenue meters along with Power Monitoring Expert (PME) software installed in a PC workstation within its main headquarters. The revenue meters act as gateways, collecting and passing data from all feeder meters over an Ethernet link to a satellite radio.

The meters can also share data with existing SCADA systems via multiple communications channels and protocols, thus creating an enterprise energy management system with real-time power monitoring and control capability on the entire distribution network. The system offers 24-hour access to real-time and logged system information for each substation. Because it uses Ethernet between meters and the satellite connection and between the satellite and the master software station at the head office, the speed of the system enables a true real-time monitoring of energy and power quality conditions. This type of communication, combined with the meters' intelligent capabilities like DDD, make it ideal for the wide, barren terrain of the service area. The utility has multiple meters monitoring a line at key points to tell them quickly where a fault occurs. They can quickly dispatch a truck to the fault without having to maneuver along a power line in search of the fault location.

The utility is pushing the boundaries of the intended use of the smart meters and using the technology in new, innovative ways. Not only are they using the DDD functionality of their ION meters to monitor their lines for fault direction, they can also use it at the customer service entrance. Many industrial customers use variable frequency drives (VFD's) with motors and pumps, these VFD's generate harmonics on their system as well as their neighbor and even back to the grid. By metering the service entrance, the utility can quickly tell if the disturbance is occurring along the incoming line or if it's being internally generated by the customer. Thus, when a customer contacts the utility to complain about issues, the utility can use DDD to quickly determine the location and direction of the fault. Often, utilities will discover that the disturbance is being generated by other customers along the line, sometimes just next door. When multiple companies call the utility to protest, the utility can discover the offender quickly by examining fault direction.

Meters with DDD capability can replace fault detectors for utilities, but greater value may be in determining where the harmonics are coming from in order to correct the problem. Harmonics have a negative effect on the power quality of any nearby homes or businesses. With multiple meters at key points along distribution and feeder lines, disturbance direction detection helps identify the problem and the location very quickly, maximizing the time and efficiency of workers in the field.

Ultimately, advanced smart metering for utilities can delivers benefits that conventional metering systems cannot: an energy intelligence that merges electricity, communications, and information systems – elements that were once separate, but operate more efficiently together. The technology helps energy providers track their performance, stay informed of critical conditions and make empowered, strategic decisions. An advanced smart metering infrastructure could link to asset management and operational efficiency metrics to maximize the use of resources and improve service. Today's forward-thinking energy providers continue to push innovation and partner with other innovators to design and transform the grid that will keep us supplied with clean, reliable, and affordable energy for tomorrow. There will be smart grid innovations to come that will transform our energy in ways we can't yet imagine.

About the Author

Steve Kuperman is a Director of Business Development for Utilities in Schneider Electric's Ecobuildings business.

Previously Mr. Kuperman has held positions with Schneider Electric's Relay Business, Wind and Regional Manager for MV Products in the South Central US. He currently resides in Houston, TX with his wife and children.

From Research to Action

How to Navigate Existing Cyber Security Risk Management Guidance

By Annabelle Lee

Currently, the nation's power system consists of both legacy and next generation technologies. This increased digital functionality provides a larger attack surface for any potential adversaries, such as nation-states, terrorists, malicious contractors, and disgruntled employees. The U.S. federal government has responded to all of these changes in technology and the threat environment by developing and updating cyber security guidance. Utilities are dedicating significant resources to understand the guidance and determine what is applicable. For many utilities with limited cyber security technical expertise, attempting to understand and implement all this guidance is daunting. EPRI initiated a project last year, not to develop a new guidance document, but to assist utilities in navigating all the diverse existing guidance that is applicable to the electric sector that resulted in three new reports:

- *Risk Management in Practice – A Guide for the Electric Sector* [1]
- *Security Posture using the Electricity Subsector Cybersecurity Capability Maturity Model (ES-C2M2)* [2]
- *Cyber Security Risk Management in Practice – Comparative Analyses Tables* [3]

New grid technologies are introducing millions of novel, intelligent components to the electric grid that communicate in much more advanced ways (two-way communications, dynamic optimization, and wired and wireless communications) than in the past. These new components will operate in conjunction with legacy equipment that may be several decades old and provide little to no cyber security controls. In addition, with alternative energy sources such as solar power and wind, there is increased interconnection across organizations and systems. With the increase in the use of digital devices and more advanced communications, the overall cyber risk has increased. For example, as substations are modernized, the new equipment is digital, rather than analog. These new devices include commercially available operating systems, protocols, and applications with vulnerabilities that may be exploited.

Address a constantly changing environment

Some utilities have the technical expertise to assess and use the various documents as part of an overall cyber security risk management program. However, not all utilities have in-house expertise and must rely on external organizations and guidance. In addition, some utilities are being asked by management and by regulatory organizations, such as state public utility commissions (PUCs), to demonstrate how they meet the requirements and/or content of these various documents. Currently, responding to these requests is difficult because there is no overarching guidance that tells utilities how to get started.

To address this constantly changing environment – including new technology, threats, guidance, and regulations, EPRI initiated a collaborative effort with DOE, utilities, the trade associations, Carnegie-Mellon University, and researchers. The goal was to assist utilities in assessing and applying the various cyber security documents, rather than developing new guidance.

Follow the flowchart

The first task was to develop a flowchart (Figure 1) that related the guidance and methodologies of an enterprise risk management process and strategy, focusing on cyber security. All the new cyber security guidance needs to be included in the context of an overall enterprise risk management process and strategy. The following flowchart has been used by utility cyber security staff in meetings with management, to provide an overview of cyber security.

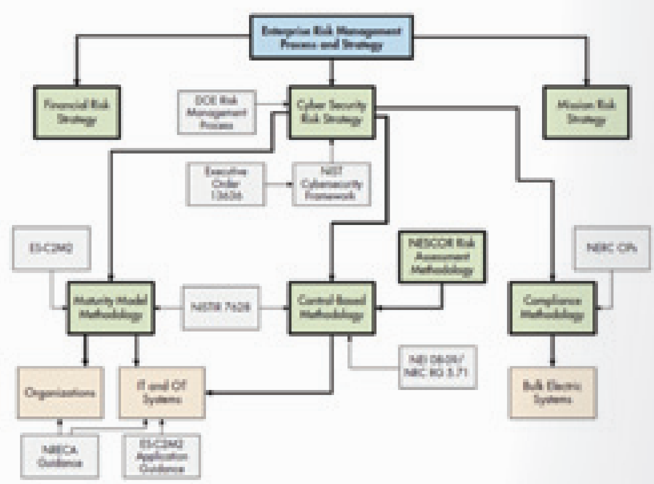


Figure 1 Risk Management Guidance Flowchart

Standardize the guidance and make it free

The second task was to provide a comparative analysis of the referenced documents. All of the documents included in the diagram are at different levels of specificity and may be used for different purposes related to managing cyber security risk. For example, the ES-C2M2 may be used to determine the maturity level of an organization and the National Institute of Standards and Technology Interagency Report (NISTIR) 7628 security requirements may be used as part of a cyber security risk assessment of specific control systems.

Currently, there are many versions of the comparative analysis—developed by utilities and contractors. The goal of the EPRI project was to have a common baseline set that is publicly available at no cost and may be used by everyone. The focus of the documents is to provide guidance on applying the diverse existing cyber security guidance that is applicable to the electric sector. The security posture document provides guidance for performing a maturity assessment on systems using the DOE ES-C2M2. Application guidance is included to assist utilities in this system assessment and NISTIR 7628 security requirements are allocated to specific practices within the ten domains. All three documents provide a framework and comparative analyses of existing guidance that may be used by cyber security practitioners in addressing cyber security.

The road ahead

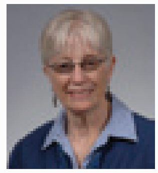
These first versions are not intended to be final—and the goal is to have people use the comparative analysis tables included in documents and provide comments for future versions.

However, we've already heard from our utility members that the standardized guidance has allowed their business units to identify risks, map risk decisions to mitigate outcomes, and model risk by mapping potential impact. We've also heard that this work has helped utility employees answer a critical question: Which documents do I need for my cyber security efforts, and where do I start?

References

1 http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002003333
2 http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002003332
3 http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002004712

About the author



Annabelle Lee is a Senior Technical Executive in the Power Delivery and Utilization Sector of the Electric Power Research Institute (EPRI). She provides technical oversight to the various projects within the Cyber Security and Privacy Program at EPRI. Her current technical focus is on applied cryptography, security specifications, and cyber security risk management and metrics. Annabelle's experience comprises more than 35 years of technical experience in IT system design and implementation and more than 25 years of cyber security specification development and testing. Over her career she has authored or co-authored many documents on cyber security, cryptography, and testing. She began her career in private industry concentrating on IT systems specifications, software testing, and quality assurance.

IMPLEMENTING CLOUD BASED SOLUTIONS FOR MISSION CRITICAL UTILITY SYSTEMS IN A NON-GREENFIELD ENVIRONMENT

Deploying T&D Cloud-based software as a service (SaaS) solutions such as load management continues to grow in popularity among organizations seeking efficient, cost-effective solutions that deliver modern operational and information technology, extensibility, and integration with future technologies. Utilities, however, have been reluctant to embrace SaaS for mission-critical solutions, such as load control, demand response and network management. Among their concerns are the complexity of their technology infrastructure and the need for utmost security. These challenges are far from insurmountable, however.

ADDRESSING COMPLEXITY

Implementing a mission-critical SaaS solution inside a legacy infrastructure, with legacy processes that are not easily changed, is a different level of challenge than working a clean, greenfield environment. Typical of a large utility, this kind of challenge demands experience as well as technical knowledge. With decades of experience implementing and hosting systems-of-systems integration projects, Lockheed Martin has developed approaches that address the most complex technology architectures.

It's critical to remember when working in non-greenfield environments that technology exists to serve business needs, not the other way around. A solution architecture must be able to bridge the legacy infrastructure to the new mission-critical solutions with little or no disruption to ongoing business processes.

ENGINEERING AND IMPLEMENTATION

With this in mind, every project should begin with a comprehensive business analysis and discovery to develop a thorough understanding and definition of a utility's business and process requirements. Next, those requirements and processes are mapped into technical, system-level documents. Engineers create detailed use-cases that define how the new solution is to be used and what information is required from legacy systems. Implementation requirements are defined for the new mission-critical solutions, and legacy IT systems that will support existing and potential new business processes are identified.

The final step, implementation, demands an experienced team to ensure a smooth integration of all solution elements. Lockheed Martin has decades of experience with Department of Defense and other federal government systems, providing a unique foundation of integration techniques and architecture patterns to bridge complex and antiquated systems.

THE SECURITY ISSUE

Utilities are understandably concerned about cyber security threats when they consider outsourcing mission-critical software solutions. However, SaaS solutions are actually less vulnerable when they're hosted in secure facilities with proper protocols and threat-protection solutions.

Lockheed Martin deploys some of the most secure hosting infrastructure solutions in the world for customers that include the DOD, Federal Aviation Administration and the Department of Energy's Nuclear Regulatory Commission. Moreover, the corporation has one of the world's most sophisticated cyber security threat monitoring solutions, providing services to DOD, civil agencies, and Fortune 500 customers, as well as our exsiting utility customers.

With these proven capabilities, Lockheed Martin is able to provide secure, effective mission critical systems for electric delivery and distribution management.


EXPLORE THE NEXT GENERATION OF
ENERGY INNOVATION.
AT LOCKHEED MARTIN,
WE'RE ENGINEERING A BETTER TOMORROW.
With over 100 years of innovation experience, Lockheed Martin is collaborating with customers, universities and industry to solve the energy challenges of today and tomorrow.
Visit lockheedmartin.com/energysolutions
LOCKHEED MARTIN

Strategies for Successful Storm Response and Management

By Bruce Bjorklund and Rich Cummings

It's a beautiful day in your service area, and your distribution operations control center has few to no outages for operations to deal with; everything at your utility is status quo. Tomorrow, however, a major storm is predicted, so everyone gears up and gets ready to deal with the situation. As the storm impacts your utility's service area, the number and duration of outages exceed expectations, but you are prepared and manage the storm well. The local press coverage is largely positive because you were able to limit the number and duration of outages, which reduced costs and business impacts and left your customers happy about how efficiently your utility handled the situation.

Unfortunately, this scenario doesn't happen often enough in our industry. Utilities are facing increasing pressures from legislators, regulatory agencies, electricity consumers, and the general public to manage better and communicate on their storm outages and restoration efforts. Key questions include:

a) How does a utility achieve successful storm response consistently?

b) What are the elements for a well-managed storm?

COMMON SHORTCOMINGS OF STORM RESPONSE

Most utilities have storm process pains resulting in inefficiencies in one area or another. Common shortcomings of storm response include:

- Failure to account for people, system and process changes such as staff retirements and system upgrades
- Inadequate Stakeholder awareness and involvement
- Limiting preparation to the period before the storm season starts
- Insufficient time allocated for preparation and knowledge development
- Lack of role-based training and simulation
- Lack of a comprehensive Storm Response Plan

STORM PREPARATION AND CORRECTIVE ACTION

A number of best practices exist for storm preparation and management. These include enabling the right people, systems and processes; In-depth analysis of storm profiles; and leveraging storm simulation technology to provide real-world storm response practice. Table 1 provides a checklist for developing a comprehensive Storm Response Plan.

Table 1: Storm Response Planning Checklist

Items in red are often overlooked or minimized. These items drive storm response consistency and positive media coverage.

Strategy	Action
Resources – changes	Assign resources to roles. Review retirement eligibility and succession planning for key roles
System changes	Review critical IT system changes, schedules and role-based impact. Adjust schedules to minimize the impact top storm season
Process changes	Evaluate planned organizational changes, system changes, and corrective actions from previous post incident critiques and the related role-based process revisions
Event Profiling	Create evaluation criteria data sheets and gather or evaluate against rolling ten-year data. Hint: Make this a component of every event debrief – create a dashboard
Event Segmenting	Segment results into low, medium, and high impact events. Incorporate even debrief comments for evaluation
Stakeholder report out	Summarize findings and recommended planning for corrective actions
Gap resolution	Budget, assign, and manage corrective actions to closure
Storm Response Level	Update level criteria based on data and debriefing observations.
Updates	Look critically at lead time and geography related decisions and actions.
Create preparation timeline	Create the off season timeline and response group definition revisions from previous year success and failures. Create call out schedule for the upcoming season. Best and most experienced leading this effort
Review foundational training	Identify revision requirements. Revise, schedule, and deliver
Review role-based training	Identify revision requirements. Revise, schedule, and deliver
Review small group simulations	Identify revision requirements. Create new simulation scripts, schedule and evaluate small group simulations
Determine Multi-site drill scenario and timeline	Establish drill objectives by role. Identify key inputs and expected responses. Identify controllers/evaluators. Schedule training for controller/evaluator roles
Stress Test systems	Ensure system can respond to high volume events when loaded with data and users
Create backup plans	Identify manual processes for critical system failures

People, System and Process Changes

Analysis of people, system and process changes should occur early in the storm response planning process to minimize their impact to successful outcomes when high volume events occur.

A key consideration is the loss of experienced personnel as they reach retirement age. This loss results in a significant reduction in the experience level of the employees that remain and creates a knowledge void that can adversely impact a high volume event.

With regards to systems, utilities are experiencing increases in the amount of enterprise technology and the related changes that get implemented in the lifecycle of their management systems. These systems can include:

- Geospatial Information Systems
- Mobile Workforce
- Energy Management System, Distribution Management System, and Outage Management System
- Radio / Phone Communication Systems
- Work Management System
- Damage Assessment Tools

The timing of implementations, upgrades, and the need for training end users must be a key consideration. The proficiency required using the technology during a 'blue sky day' is very different than during a 'high volume event.'

Process change occurs when the utility makes organizational changes or system changes to adapt to business needs or challenges. These changes are commonly overlooked when preparing for high volume events.

Storm Profiles and Past Event Analysis

All utility stakeholders, from executives to storm responders, need to understand the types and frequency of system events and storms. Reaching back as far as ten or more years can provide a realistic picture of how events have impacted the business.

When developing storm profiles, measure the following types of variables:

- Event type
- Date of event (time of year)
- Prep Time – the time from event awareness until the event impacts service territory
- Escalation time – the time from event start until event peak
- Number of customers out of power at event peak
- Duration of event peak
- Average customer minutes of interruption
- Number of line crew personnel responding
- Volume of Assets Damaged (# poles, #OH transformers, # cross-arms, # insulators, miles of conductor, etc.)

Clustering storm profiles by event type and analyzing the data to segment type and impact provides a number of benefits for planning purposes. For example, the most typical event types can be identified, along with the time of year they occur. The average length of low, medium, and high impact events can be established. For each type of event, analysis will indicate the average lead time before the event and the average number of line crews utilized in past response efforts.

Knowing the typical event profiles and then segmenting the event profiles into categories by event type can assist in planning for future events. This analysis provides data based evidence that will assist in validating post-event critiques and determining corrective actions. With this information, response profiles can be created and leveraged in planning, training and drills.

TIP: *Make storm profile data available after every event as a component of post-incident critique, from the dashboard.Use this data to identify improvement opportunities and practice corrective actions in exercises.*

Storm Response Level Updates and Geographic Considerations

Storm response level criteria should be reviewed and updated annually based on the profile data and debriefing observations. The following is a typical example of a four level criteria for event activity that drives the utility response taking into account duration, impact to utility-system wide and geographically, weather type, and severity:

- **Level 1**: <15,000 customers out of power; Light damage to the distribution system; Limited lightning with intermittent wind/rain; Winds less than 20mph with gust under 30mph; Isolated areas of impact with a predicted short duration forecasted.
- **Level 2**: 15,000 to 50,000 customers out of power; Multiple areas impacted with less than 25 percent impact to transmission or distribution systems; Weather impacting wider range with sustained winds of 30-35mph and gusts up to 40mph; Impact is over region or widespread multiple small geographies; Weather event is slow moving with a 4 to 13 hour duration forecasted.
- **Level 3**: 50,000 to 150,000 customers out of power; Multiple areas impacted with greater than 25 percent impact to transmission or distribution systems; Weather impacting majority of the service area with sustained winds of 40+mph and gusts up to 50mph; Impact to most of region or widespread to multiple large geographies; Weather event is slow moving, heavy rain, tropical depression, hurricane or tornadoes predicted with 12 hour or longer duration forecasted.
- **Level 4**: <150,000 customers out of power; Multiple areas impacted with greater than 50 percent impact to transmission or distribution systems; Weather impacting entire service area with sustained winds of 45+mph and gusts over 55mph; Impact to entire region or widespread to multiple large geographies; Weather event is slow moving, heavy rain, tropical depression, hurricane or tornadoes predicted with 24 to 48 hour or longer duration forecasted.

The important take away is that these level definitions come from the analysis of storm profile data and corrective actions from previous experiences. The decision to open storm bases, activate mutual aid, activate the emergency operations center, etc. is based on past experiences and successes or failures. For early success when augmenting the response staff, make call outs sooner, and be 'over-prepared', and then demobilize if necessary to insure that sufficient resources are available in advance of rapid escalation.

Regardless if your service territory is rural, multi-state, or condensed to a city, there are challenges in getting first responders, crews and materials deployed. Traffic, road closures, and poor conditions can bring a storm response to a crawl. Leveraging the lead time before event impact, along with staging equipment and resources, can be a significant advantage for your customers. Staging resources in the right locations is especially valuable. Critical infrastructure such as 911 call centers, hospitals, water treatment pumping stations, radio and television stations are a response priority. Mutual aid agreements can be a game changer even in smaller events when geography is a challenge. It may be strategically and tactically better to consider how a neighboring utility or contractor firms might be able to assist you in some geographic areas. Could you place materials, park trucks or trailers, or stage equipment at their locations before the season, or even before the event?

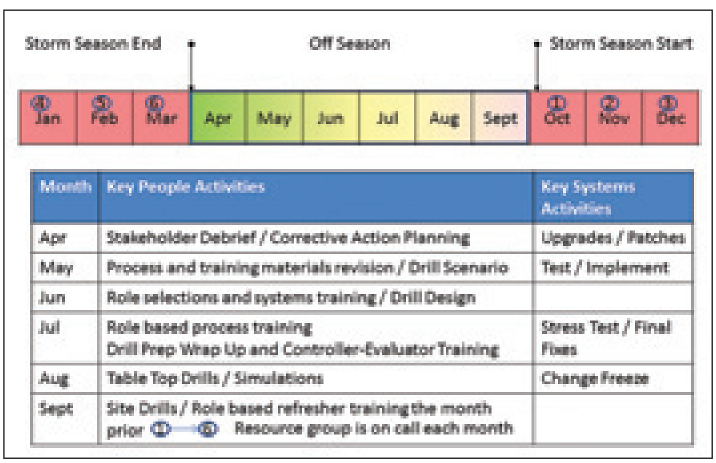
Preparation Schedule and Resource Groups

Preparing for events or storms often gets compartmentalized into the weeks and months just before the 'typical' season starts. There is a host of last minute, abbreviated, and inconvenient meetings and training presentations that do little more than fill a checkbox on the list with a checkmark. Sometimes the first storm is the preparation, and consistency isn't even on the table for consideration.

TIP: *Preparation for the next season should begin the day after the previous season ends.*

Rigor is required to create consistent event responses, and procrastination is the enemy. Storm profile data and debriefs from previous year post-incident critiques is critical to preparations.

Figure 1 shows an example preparation schedule and activities. In this example, the storm season begins in October and ends April 1st. The people and system activities indicated are aligned around the people, process, and system components. The idea is to analyze the previous year storm profile data, gather the post incident critique information, and then drive corrective actions. Results from these efforts translate into a lot of very worthwhile work for several different groups. This work should occur in the off season and bring the best and most experienced resources together to collaborate and drive the corrective action effort.



Month	Key People Activities	Key Systems Activities
Apr	Stakeholder Debrief / Corrective Action Planning	Upgrades / Patches
May	Process and training materials revision / Drill Scenario	Test / Implement
Jun	Role selections and systems training / Drill Design	
Jul	Role based process training Drill Prep Wrap Up and Controller-Evaluator Training	Stress Test / Final Fixes
Aug	Table Top Drills / Simulations	Change Freeze
Sept	Site Drills / Role based refresher training the month prior 1 — 6 Resource group is on call each month	

Figure 1: Storm Preparation Schedule with Monthly People and System Activities

This preparation schedule utilizes the concept of resource groups, which are denoted by the numbers 1-6 in blue circles. These six groups represent role-based sets of responders for all necessary roles that would respond in the event of; System Operator, Load Analyst, Wire Guard-Make Safe, 911 Coordinator, Damage Assessor, Vegetation Management, Dispatcher, Materials Management, General Foreman, Operations Supervisor, and Storm/Emergency Management. If there is an event in October, resource group 1 responds and if in November, resource group 2 responds.

This resource group approach improves resource allocation and training. Group 1 should be made up of the best and most experienced storm response resources, and should be heavily involved in the off-season preparation efforts. Any new or inexperienced resources are assigned to groups 2-5. If there is an October event, new resources should be expected to respond with group 1 for a callout. This model provides an opportunity for new resources to work, learn, and practice with experienced resources in a real event. Resources in group 1 can be asked to help other groups in the ensuing months if those groups are called out.

Resource groups allow just in time delivery of refresher training such that it is scheduled just prior to the on call month for a resource group. For example, refresher training for group 5 could be in January. Finally, resource groups provide a 'succession plan' for large events. In a multi-day event, having a resource plan built in can be very helpful to keep productivity high.

Training and Simulation

Training of storm response staff is required due to turnover in operating staff, with more experienced operators retiring and being replaced by less experienced personnel. However, even the most senior distribution system operators require significant training on new technologies and operating requirements.

Training simulators, which provide interactive simulation of power system operations under normal circumstances and contingencies, can prepare the response team to meet these challenges. Training simulators shorten the time needed to train up new candidate operators and reduce time spent by senior operators supporting these training activities. Interactive simulators provide a realistic training environment where learners can practice and replay "what if" scenarios.

Foundational Training

Foundational system training should be a primary consideration for new resources. There is also a need for foundational 'event or storm' training that orients new resources to the big picture. If there are a large number of new resources or a significant change in systems or process then, more time and resources may be needed to update training materials and deliver the necessary training.

Role-Based Training

New and existing resources with a solid foundation need to learn the event work processes. There must be time to create or update training materials. Training is role-based, which means every role should know their responsibilities and how to perform the tasks they will execute during the event. Role-based training should be hands-on training; process based, with realistic simulated events, delivered by the best and most experienced resources.

Small Group Simulations, Role Plays, and Drills

When every role has been trained, then small (functional) group simulations that include role play commence. These small group simulations allow responders to work together, build confidence, open lines of communication and create a 'response team.' These small group drills should validate the role-based training and provide an opportunity for practicing the event workflows between roles in a functional area. This effort gets led by the best and most experienced resources for each role.

Utilities often miss detailed small group storm training. Training should occur in stages and include role play simulations within each work group as well as individual training based upon the character actions required. For example, Damage Assessors can practice documenting and packaging equipment damage assessments and hand off this information to crew managers. Crew managers can prioritize work and resource assignments and communicate with crews. In addition, 911 Coordinators can interact with system operators to prioritize public safety responses. Simulation role play validates the processes, role requirements, and training. Each simulated role play shall include an evaluation component. The evaluation process is essential to ensuring that training requirements and work processes get implemented, and any corrective actions are captured.

In Figure 2, the planning activities lead to a drill scenario that has control injections and role-based evaluations prior to the storm impacting the service area, and through the escalation. This requirement is critical to role play and practice of the 'pre-impact' actions as the storm scenario approaches and as the scenario progresses through escalation.

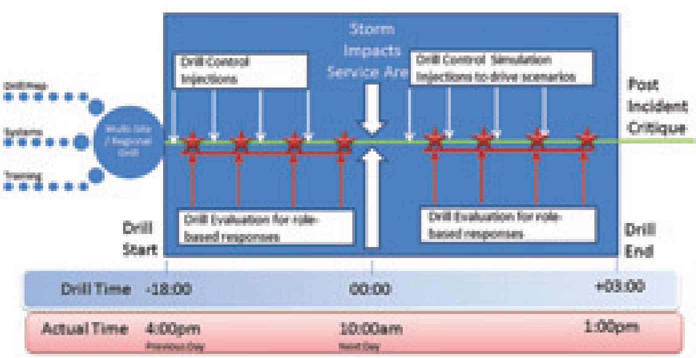


Figure 2: Training Simulation Timeline with Control Injections and Role-Based Evaluations

Utilizing a script editor allows simulated injections, driving a build up for limited outages and gradual progression of the intensity to drive storm response. Simulations should progress from the point prior to outages being received in system operations and progress through rapid escalation.

During the initial stages of the storm, pockets of small outages can be injected through the script to drive the response by the participating roles. During the initial start-up of a drill, invoke the response processes slowly and evaluate key decisions.

TIP: *Practicing slowly during the beginning of the drill helps prevent overreaction and allows the users to build proficiency in implementing the storm processes.*

As the storm simulation escalates, the role players should then begin making correct decisions based upon practice processes. During this portion of the role play, decisions should be supported by defined rules and time durations based on storm escalation. At key decision points, the utility must be proactive rather than reactive in setting up storm support personnel.

Before the storm escalates to peak, resource decisions must be made, and key players in support roles must be in place. Using system overviews and dashboards during simulation drills at all levels helps drive situational awareness that leads to making informed decisions (See Figure 3).

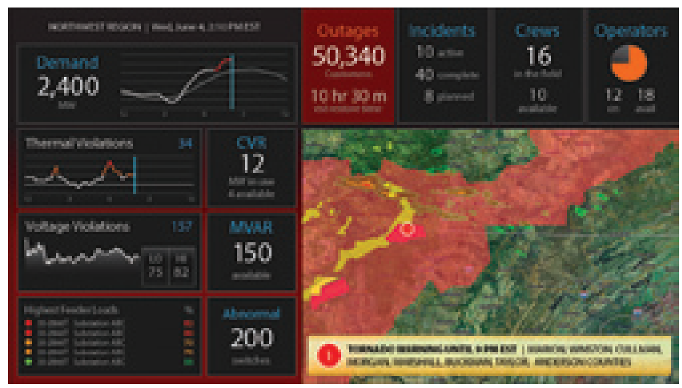


Figure 3: Overview Dashboard Displays Impact of Storm System

During the evaluation phase of the small group training, it is key for subject matter experts to validate the work process that occurs before and during a storm. By gradually working through this progression, weaknesses can be identified and practiced.

Multi-Site Exercises and Drill Scenarios

When small groups get experience and practice performing in response roles, the stage is set for a more comprehensive practice in the form of a multi-site drill or exercise. The multi-site component of this process provides an opportunity to align the response from a geographic perspective. For example, multiple service areas are hit by the event and coordination of the response and allocation of resources is across a broader area and involves more communication traffic and logistics. Often, the utility works to reduce the impact of the event to smaller areas and ends up leaving the region or area to fend for themselves during the winding down period of the event. One goal in this process is to drive the regional sites to consider supporting the hardest hit areas when they can do so. Multi-site or regional responses can focus on local geography and then augment the efforts of adjacent or hardest hit areas. This type of design in drills and exercises builds collaboration and customer focus that can be a game changer. The ability to on-board additional help in a given area takes practice. Sub-dividing a geographic region to enable on-boarding of additional responders is the goal and practicing this behavior can make a big difference to your customers.

Drill preparation for the next season also needs to occur in the off season. Again, knowing the shortcomings of the previous year and changes in systems or process is very important. Creating an over-arching drill scenario with detailed objectives designed to assess capabilities and improvements in areas of weakness is valuable. The scenario, drill timeline, goals, and objectives by role, and the timing are all part of the drill and exercise preparation. The drill and exercise process evaluates capability and identifies improvement areas. Multi-site drills and exercises utilizing simulation role play provide an opportunity to scale the response and re-allocate resources across the business based on priorities, outage duration or the amount and type of damage.

System Stress Testing

Knowing if changes, upgrades or new systems are capable of ingesting the volume of incidents and the number of users during a high volume event often gets looked over. Stress testing for high volume is a must before drills or exercises for high volume are scheduled and exercised. Communication systems should be stress tested in parallel to the high volume. Be sure to consider back-up plans for communications failures during preparation activities and test as part of the exercise process. The drill or exercise scenario can be designed to evaluate back-up plans for system failures.

SUMMARY

Storm preparedness starts from the utility leaders taking ownership of the planning and preparation process and involves year-round effort from all storm response team players. Storm simulation technology improves success by enabling the utility to conduct realistic emergency preparedness drills, preparing the total workforce to meet storm challenges.

About the authors

Bruce Bjorklund is the Lead IDMS Technical Trainer and Change Management Manager at Alstom Grid. He has over 25 years of experience in the electrical utility industry including tenures with Puget Sound Energy, Lone Peak Utility and Southern California Edison. His background also includes serving as a high school teacher and coach, Bruce has extensive experience in system operations and with OMS, DMS and GIS systems. In the past 4 years, he has interviewed and/or worked with over 14 utilities. He holds a BS in Environmental Studies and is certified in Prosci Change Management.

Rich Cummings is President of Level Four Solutions Group, Inc. (L4SG). L4SG works with utility customers in the operations, construction, and maintenance to create and deploy custom training solutions such as e-learning, instructor-led training, on-the-job training for new employees and veteran employees. L4SG creates solutions that are business and need-based, working with subject matter experts and stakeholders to improve operations during blue sky and high volume operations. Rich has 20 years of experience in training and electric system operations. His background includes tenures with the Salt River Project and working with numerous utilities for GE Energy and L4SG.

The Detroit Power Outage

A Lesson for Cities about Microgrids

By Darren Hammell

The Detroit Power Outage brought eight hours of hardship to Detroit on December 2 -- hardship that could have been averted with microgrids.

Firefighters were forced to rescue people trapped in stalled elevators. Schools shut down at lunch time. The Detroit Free Press had harsh words for city leadership.

How would microgrids help?

First let's look at why Detroit's power system failed so badly. The power outage was triggered by a cable failure that took down an already weak system. Unfortunately, blackouts are not a new problem in Detroit.

- USA Today said blackouts occurred there in 2010, 2011 and 2013. CNN said the power has gone out during several sporting events.
- McKinsey and Company received funding in 2010 to study the city's grid. They recommended $250 million of upgrades, according to Detroit Free Press.
- Detroit's municipal electric system is like a long string of old Christmas lights, tweeted SNL Energy reporter Amy Poszywak after the outage occurred.

It's important to note that Detroit isn't the only U.S. city with a vulnerable power grid. December also brought news-making power outages to San Francisco and Washington, D.C. A storm-related blackout in San Francisco on December 11 left 100,000 homes and businesses without electricity. And on December 15, a blown transformer and construction accident led to power outages in key government buildings in the nation's capital, including the State Department and the Federal Reserve. The lights even flickered in the White House.

The American Society of Civil Engineers has given the nation's power infrastructure an overall grade of D+, saying many improvements are needed. The money isn't always available, however, for massive upgrades.

How Microgrids Can Help

The frequency with which the grid goes dark is increasing in many places. When power goes out, everything grinds to a halt – unless local microgrids or generators are there to support critical facilities like transportation systems, hospitals, emergency services, and government buildings.

A microgrid is a local, customized electricity system that includes generation, storage and loads. A form of distributed energy, microgrids often derive power from solar panels, fuel cells, wind turbines, diesel, or combined heat and power (CHP).

In the United States, microgrids are usually connected to the centralized grid. But at times when local electricity is needed, the microgrid can be disconnected or 'islanded' from the centralized grid and can operate on its own, providing power to critical buildings when the grid cannot.

Why Financing Is Crucial

So why aren't there more microgrids?

The microgrid industry has been developing gradually in North America and internationally. It is largely driven by military installations, climate resilience policies, off-grid communities, and the fuel costs of islands. Since Superstorm Sandy, interest in resilience has translated into heightened awareness of the need for microgrids.

However, many city leaders still do not yet fully understand the technology and its benefits and costs. Education is key.

Energy storage and microgrids are not as expensive as is commonly held; costs are falling. Lithium-ion batteries, which are ideal for microgrids, have dramatically dropped in cost as they have been commercialized. These costs will continue to come down with market expansion. Energy storage is already cost-effective in certain places.

It is taking time for financing to catch up with the opportunities that exist. There is some financing available for full off-grid systems and some for behind-the-meter systems. But microgrids are still considered high risk by investors. It is likely financing options will improve to catch up with the market during the next few years.

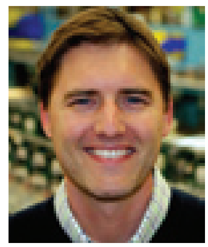
When Policy and Standards Align

Meanwhile, states like Connecticut, New Jersey, New York, and others are ramping up government incentives and policies to help the industry launch. At Princeton Power Systems, we are advocating for more coordination with stakeholders to create new codes and standards so states can coalesce around a more common approach.

We also are encouraging policymakers and regulators to require solar to be microgrid-ready. The deployment of solar is going to continue to expand during the coming decade. The idea of energy storage and microgrids will become more closely linked to solar than it has been in the past. To prepare for this and keep costs in check, we would like to see state policy and military policy specify that solar systems built now be compatible with microgrids. This would allow them to act as islanded systems and pair with energy storage.

If we're going to put money into resiliency and reliability, we should focus on microgrids and distributed generation. It will make economic sense in more and more places as the years go by, especially in cities with aging electric infrastructure. By installing microgrids these cities can avoid becoming a cautionary tale like Detroit.

About the author



Darren Hammell graduated with honors from Princeton University with a B.S.E. in Computer Science. He took home top honors in the Princeton University Business Plan Contest and co-founded Princeton Power Systems in 2001 where he served as President and CEO until March 2009. From there he took on the responsibility of Executive Vice President of Business Development. He is currently Chief Strategy Officer.

Giving Marketing the Energy to Succeed

By Carrie Owens

Energy and utility marketers are a unique breed facing the remaining vestiges of a conservative and cautious market with an influx of technology that is bringing change at an ever increasing pace. With this dynamic landscape in play, the way the energy industry markets itself is changing. It's vital for energy CMOs to lead in new ways, to truly know their markets and to have clearly defined messages to the right target audiences. To that end, the McDonnell Group 2nd annual Energy & Utility B2B Marketing Benchmark Study is designed to look at the unique reality – challenges and opportunities – for B2B marketing in our industry.

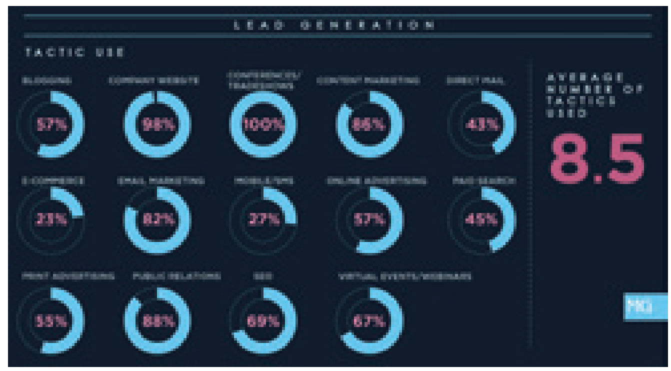
Last year's study highlighted the struggle marketers are facing, including not holding the strategic position that it should in order to address the CEO's challenges and navigate the changing marketplace. It was also clear marketers were not measuring the effectiveness and success of programs to adjust course, make impact and have the 'capital' to demand the seat.

But, as originally intended, the study also brought forward the first existing baseline for B2B marketers in our industry to compare their programs and approach to marketing to others in the same space.

This year's results serve to verify last year's findings and underscore the marketing climate marketers are operating in as they work to get their companies ahead of the change that is upon the industry. While results indicate that a shift could occur in the not-so-distant future, there has not been much change in the inbound/outbound approach. Outbound being the traditional methods of marketing (print advertising, billboards, telemarketing and direct mail) that are pushed to consumers versus inbound marketing (blogging, content publishing, search engine optimization and social media) focusing on creating quality content that pulls relevant prospects and customers towards the company and product. The 2013 survey results show 9 percent of respondents focused on inbound marketing, 61 percent focused on outbound, and 30 percent focused on both equally. 2014 results are similar with:

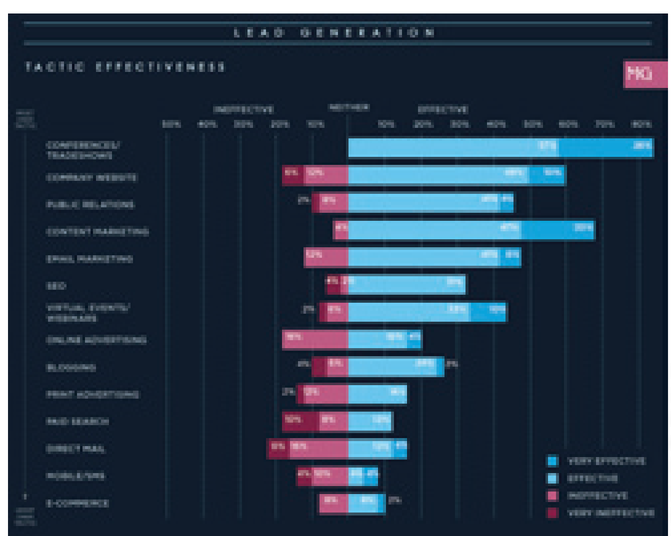
- 10 percent focused on inbound
- 65 percent focused on outbound
- 26 percent on both equally

Inbound not only increases revenue, but also accelerates company growth and increases profitability. Marketers in this industry must start making the shift to inbound marketing in order to offer their audiences useful information and tools to attract people to their website, while also interacting and developing relationships with these potential customers.



When considering lead generation, there is a slight shift in the *most often used* marketing programs/tactics. In 2013, the top four most used tactics were: company website (97%), conferences/tradeshows (96%), content marketing (92%), and email marketing (85%). In 2014 marketers identified the following:

1. Conferences/tradeshows (100%)
2. Company website (98%)
3. Public relations (88%)
4. Content marketing (86%).



As for the *most effective* programs/tactics for lead generation, in 2013 the top four most effective tactics were: conferences/tradeshows (85%), content marketing (61%), company website (58%), email marketing (49%). In 2014 the most effective were:

1. Conferences/tradeshows (83%)
2. Content marketing (67%)
3. Company website (59%)
4. Email marketing (47%).

While some industries debate the effectiveness of face-to-face events, in the utility and energy space, events are still a main method of networking, collaborating and brainstorming. Even with decreasing travel budgets and virtual interactions on the rise, conferences and trade shows are still seen as a viable and highly effective way for generating leads and extending the reach of the brand. Forty-seven percent of marketers predict they will spend an equal amount of money on tradeshows in 2015 as they did in 2014.

When digging more into digital marketing tactics, respondents stated that email marketing is the easiest to execute (51% very easy/easy) followed by online advertising (41%). Blogging ranked the most difficult to execute (52% difficult/very difficult) followed by virtual events/webinars (36%) and content marketing (34%).

However, even with content marketing being the 3rd most difficult tactic to execute, and lack of time considered the greatest barrier to overall marketing success, when asked what the most exciting marketing opportunity they saw for 2015, an overwhelming 69 percent identified content marketing as the next big thing.

In the Content Marketing Institute's 2014 5th annual content marketing survey, 70 percent of marketers say they are pumping out higher volumes of content than a year ago. More than ever, B2B marketers are focused on serving up content, an inbound marketing tactic, which helps customers engage and accelerate through the buyer journey.

Are We Making Any Progress?

There is so much data in the study, but with the conclusion of this year's study, the big question is…are we making any progress?

In regards to marketing's inclusion in the C-suite, there seems to be little progress as both the 2013 and 2014 study results identified only 25 percent of participants had a marketing executive in the C-Suite. The 2013 data identified 35 percent of respondents with a CMO/VP title compared to 43 percent in the 2014 study. Based on last year's findings, some questions were added to the 2014 survey, and when asked how their companies viewed the importance of marketing, only 20 percent indicated that their companies saw marketing as critical with an additional 41% indicating that marketing is seen as very important.

This is staggering when you consider that the traditional 4 P's of marketing (product, price, placement, promotion) are the very lifeblood of any business. It is marketing that defines the distinctive features and benefits of the product or service, sets the price and communicates those features and benefits to the appropriate audience.

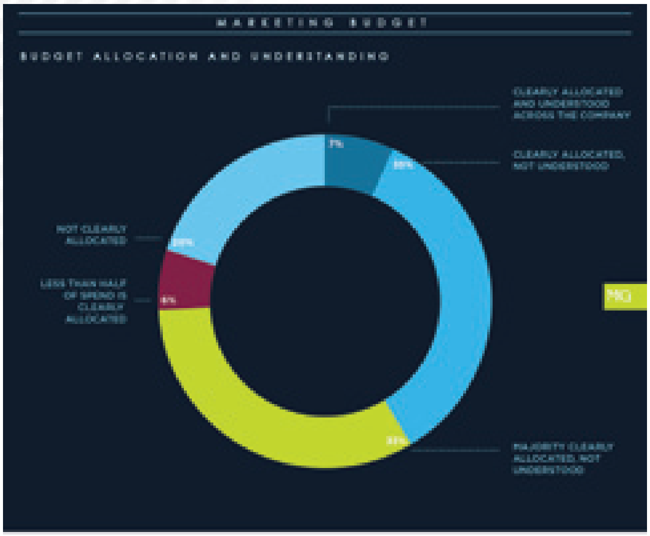
What's Holding up the Progress?

Lack of measurement

In 2013, 29 percent of marketers identified they do not measure marketing effectiveness at all, compared to the 35 percent from the 2014 study. Measurement and analytics moves marketing away from distractions and toward growth. Without it, marketers struggle to determine what is truly effective and what is not in order to course adjust. Plus, it is difficult to track how marketing programs contribute to corporate goals and show how marketing programs directly impact sales.

Lack of budget transparency

In 2013, 18 percent indicated marketing spending is clearly allocated and understood across the company, while 21 percent indicated it was clearly allocated, but not always understood. In 2014, only seven percent indicated marketing spending is clearly allocated and understood, while 35 percent indicated it was clearly allocated, but not always understood. Understanding this, the number with budgets clearly allocated went up from 39 percent to 42 percent.



This begged the addition of a question in the 2014 survey concerning whether or not companies have a documented marketing strategy. The answer to this question is tightly aligned with what one would expect based on other responses, with only 33 percent identifying they have a documented marketing strategy. An additional 41 percent said they have one, just not documented. However, a full 26 percent answered that they do not have a marketing strategy.

Lack of data

Marketing decisions need the support of research. While marketing strategy is numbers driven, the research shows 52 percent of respondents have five percent or less of their budget allocated for market research.

When asked to describe their company's approach to market research, only 13 percent identified that market research is embedded in their company DNA, while 60 percent said it was either not important or recognized as important but not funded. The most common form of research performed by participating companies was Customer Satisfaction Surveys (50% had conducted CSAT, of which 27% have an ongoing program or conduct often [23%].) This was followed by Market Segmentation at 41 percent. So what was the least common? Marketing Effectiveness at only 12 percent, followed by Brand Perception/Awareness at 15 percent.

What Are the Opportunities?

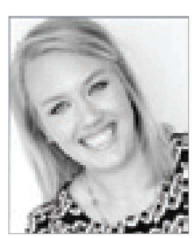
Even with the increasingly fast-paced environment that is changing the dynamics of our industry, marketers have a positive outlook on 2015 with 85 percent being optimistic or very optimistic about their company's potential growth and 70 percent saying the same about the industry's overall potential. Yet the opportunity is great for marketers to step up to lead their companies to success.

Marketing has evolved from 'vertical to holistic' as it has grown from the 4 Ps to the need to delight and draw closer to the customer. This is so we can better know them, anticipate their needs and build real relationships to create a meaningful, two-way dialogue between company and customer. We can do this through the use of data. Data-driven marketing drives efficiency, enables smarter decisions and propels a competitive advantage in the marketplace.

In today's B2B marketing world, personalization of customer data will let us build actionable strategies. With meaningful data, marketers can create winning plans that will drive better sales and give them bigger returns on investment. In addition, marketers must also track marketing involvement across every touchpoint, connecting the measurements across multiple channels to crack the metrics code, so we can know what is working and what isn't. By tracking and analyzing marketing effectiveness and having the numbers to back it up, we then have the power to adjust and steer marketing programs while having the metrics when talking to the C-Suite.

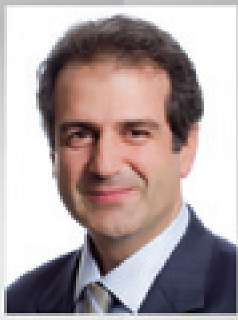
Interactivity through social media and content publishing is transforming the nature of the brand and relationships with customers and prospects. Fifty-five percent of B2B buyers search for information on social media as part of their discovery (source: MediaBistro) means focusing more on delivering content via social media to increase awareness.

All of this points to the opportunity for marketers in this industry to better know the environment in which we are operating, know what others are doing that works and what doesn't work, in order to set goals and give marketing the energy and the strategy to succeed.



About the author

With over seven years of experience as a marketer in the utility industry, **Carrie Owens** is currently the marketing account manager for McDonnell Group, the leading integrated marketing firm for the energy and utility industry. She works with her clients in the creation and delivery of integrated marketing programs, providing strategic and tactical direction to propel them to market leadership and build value for their businesses. Prior to joining McDonnell Group, she was the public relations and marketing manager for EnerNex.



THE BIGGER PICTURE

BY ED ABBO

Keeping up with the Cloud

The rapid growth of hardware investments in smart grid opens up a new opportunity for utilities to take advantage of next-generation information technology, such as cloud computing, to fully unlock the insights and value that a modern grid has to offer. However, outdated state rate regulations and accounting rules, have not kept pace with, and actually impede, the ability of utilities to benefit from the new IT models that will substantially improve system performance, reduce capital and operating costs and hardware risk, and produce substantial economic value to utility customers and shareholders. Under current guidelines, utilities may classify investments in legacy hardware and supporting on-premise software as a capital expense, which can be included as part of the rate on which it can receive a return. Counterintuitively, if a utility wants to invest in state-of-the-art cloud-based technologies that both enhance the performance of legacy and new hardware systems and that eliminate the need for continual procurement of more expensive new IT hardware, a utility typically must treat the investment as an operating expense for which it does not receive a rate of return. This difference in treatment creates a perverse incentive to pursue more costly, less effective, and riskier on-premise technology investments and deprives rate payers of the immense performance and economic benefits of the more advanced technology innovations that many other sectors are now experiencing. A simple update of rate regulation and accounting rules can fix this problem.

This decade, utilities are investing billions of dollars to make the devices in the power grid remotely IP-addressable, including, for example, the nearly 1.1 billion smart meters that will be installed by 2022, according to Navigant Research. While representing only a fraction of the sensored devices on the grid, the number of smart meters provides a good indication of the growth rate of the smart grid.

All of these hardware advances, however, are of limited usefulness without the cloud-based software innovations that will actually make the smart grid ‘smart.’ As the grid increasingly becomes sensored, an unprecedented amount of data are produced, which can only be addressed using the most state-of-the-art information technology. IT offerings have rapidly evolved to today’s innovative cloud computing models, including Software as a Service, Platform as a Service, and Infrastructure as a Service. With these, come opportunities to leverage numerous capabilities essential to fulfilling the promise of the smart grid – continuous access to increased processing speeds and power, more flexibility and mobility, elasticity/on-demand surge capacity, and lower costs through scale.

However, the U.S. regulatory and accounting treatment of cloud computing models has not kept pace to take advantage of this technology opportunity, and utilities are faced with undue consequences when they select a cloud computing offering because cloud computing and on-premise software solutions are treated quite differently. The existing guidelines are based on 20-year-old business models, which classify last-generation on-premise software licenses as a capital expense, and modern cloud computing arrangements as an operating expense. The classification as a capital versus operating expense influences a utility’s ability to obtain rate-base coverage consistent with other capital expenditures and incentivizes investments in antiquated technology.

In order to accelerate the goal of a modern electric transmission and distribution system, advanced cloud-based IT offerings are necessary. Regulation should respond to remove illogical barriers and provide the same incentive to deploy cost-saving, high-performing software systems that a utility already receives for investing in other technologies or smarter equipment.

On-Premise Software

The traditional software model provides a physical copy of the product on-premise under a license agreement. The license allows the vendor to restrict use of the software, for example by limiting access to a certain number of users or installation to a certain number of servers, and preventing reverse engineering.

These licenses are typically structured as ‘perpetual’ or ‘term’ arrangements. A perpetual license is a right to use software for an unlimited period of time – it is paid for once and does not have to be renewed. A term license is a right to use software for a specified period of time and requires renewal of the license at the end of the term for continued use.

Both perpetual and term licenses typically include an annual maintenance arrangement to support updates, ongoing customer service, and other incidental activities, but the responsibility for the application upgrades, patching, administration, and hardware infrastructure operation and management is left to the utility. The distinguishing feature for utility IT teams is that the software vendor grants the use of a copy of the software under the license arrangement, but the teams must manage the operation of the software.

Cloud Computing

Over the last decade, a rapidly growing number of companies have shifted from buying these on-premise software components under perpetual or term licenses, to leveraging software built, managed, and continually improved by someone else. These companies are replacing traditional on-premise software applications and platforms – even underlying IT infrastructures – with the same kind of cloud-based solutions, or cloud computing.

Cloud computing refers to the use of Internet-based computing to deliver a variety of product offerings. Under cloud computing arrangements, the customer has a right to use or benefit from the functionality of software but does not receive a copy of it. These arrangements are typically structured under subscription models.

Under a subscription, the software vendor agrees to deliver one or more of its software products at the time of contract, and unspecified additional software updates during the term of the subscription. A subscription differs from a perpetual or term license in that it provides customers with a turnkey solution that includes application management, monitoring, patching, and upgrades as well as hardware infrastructure and operations. While these software applications can provide similar solutions to on-premise software, they have the added enhancements and benefits of the mobility, scalability, and elasticity of the cloud.

The most common cloud computing models for utilities are Software as a Service (SaaS), Platform as a Service (PaaS), and Infrastructure as a Service (IaaS). With a SaaS model, utilities pay to use an Internet-based software product hosted by the SaaS solution provider. SaaS solutions used commonly by utilities today include applications such as C3 Energy for smart grid analytics, Esri ArcGIS for geographic information systems, and SmartGridCIS for billing and customer information systems. Typically, SaaS solutions are service-based, scalable and elastic, and metered by use. By 2016, IDC estimates that SaaS solutions will constitute about 14.2 percent of all software spending and 18 percent of all applications spending, with a compound annual growth rate of 21.3 percent.

PaaS models are more commonly used by developers. With these solutions, utilities pay to use a web-based platform hosted by a software vendor or a third party to design, develop, and test their own applications. The most common examples of PaaS solutions in use today include Salesforce.com and Microsoft Azure. Specific to big data and the energy market, C3 Energy's data analytics platform has also been designed as a PaaS solution.

Image courtesy of C3 Energy

Cloud computing, or Internet-based computing, allows for continuous access, more mobility, and elasticity compared to traditional on premise software. One example of a SaaS/PaaS solution is provided by C3 Energy for smart grid data analytics.

Finally, IaaS allows utilities to pay to use a virtualized service environment such as computers, systems, hardware, network bandwidth, etc. maintained by a vendor. Utilities can rent (rather than own their own) servers or operating systems to run their choice of software solutions. According to a KMPG analysis, implementation of IaaS can save 30 to 60 percent of IT infrastructure costs. Amazon Web Services is the current leader in this area.

In each of these models, the solutions are basically rented by a utility instead of purchased outright. This allows utilities access to the latest advances in technology, mobility, elasticity, and scalability to realize operational efficiencies. Without having to invest in hardware and software to meet their maximum requirements upfront. For example, utilities can increase capacity on-demand to meet specific timelines and requirements and then scale back as appropriate. However, regulation has not kept apace, and despite the efficiencies available, utilities are disincentivized to invest in these solutions and are conversely motivated to continue with obsolete technology invesments.

Accounting for the Cost of Cloud Computing

Currently, U.S. generally accepted accounting principles (GAAP) do not have specific guidance that addresses accounting for cloud computing arrangements, so utility regulators have no clear roadmap. This results in differing representations of on-premise and cloud computing arrangements in financial statements.

With no explicit guidance, utilities are following 20-year-old business and technology models, with the following disparate result:

- Perpetual software license: Capital expense
- SaaS license: Operational expense
- Term License: Operational or capital expense, depending on the arrangement
- One-off treatment as an approved regulatory asset: Capital expense

These differences in accounting classifications are inconsistent, given the similarities of the solutions. Both arrangements are similar in:

- the rights conveyed and restrictions imposed;
- the benefits derived;
- the nature of the arrangements whereby a customer is granted the right to use software over a specified time; and
- the maintenance, upgrades, enhancements and support often included in both types of contracts.

On-premise license arrangements treated as a capital expenditure are recognized as intangible assets at inception of the arrangement and amortized over the life of the arrangement. Cloud computing arrangements are accounted for as executory contracts by a majority of utilities and recognized as operating expenses over the term of the arrangement. The resulting difference in accounting treatment is prohibiting utilities and their customers to access the added benefits and technology innovation inherent in cloud computing.

If a utility licenses software in conjunction with investment in operating equipment (meters, substations, sensoring on distribution system, etc.), then both the hardware and software investments are typically capitalized as a bundle. For example, if a utility purchases smart meters that have an analytics layer bundled into it both the hardware and software are categorized as a capital expense. However, if a utility wants to license software that improves performance of existing operating equipment, independently of a hardware purchase, than the utility must go through a non-optimal path to achieve capital treatment of the software investment.

In addition, an on-premise software license model also requires a significant capital investment in IT hardware (servers, storage, etc.), which rapidly becomes obsolete, but in the SaaS model the acquisition of IT hardware is not necessary as it is bundled in the SaaS model, and can take advantage of continuous advances and investments in higher performing IT hardware owned and managed by cloud service providers.

Solutions

The work-around for some utilities wishing to capitalize SaaS arrangements has been to characterize the arrangement as a term license and justify capital treatment by analogy, using capital lease rules. This approach is not as clear as it would be for a perpetual license, and in many cases not optimal for the utility.

Instead of utilities being burdened with confusion and inconsistencies on their balance sheets, rate regulations should catch up with software innovations in order to accelerate the goal of a modern transmission and distribution system. Regulators must understand the issue at stake and create regulations that support utilities in ways that deliver even greater benefits to their customers.

Utilities should not be penalized or discouraged from investing in technology advancements. Instead, utilities should be leading the way to a more modernized electric system. In order to do so, they need simple clarifications on rate recovery rules on a national or state-by-state basis to support a model rule for capital treatment of cloud computing solutions.

To move forward, utility regulator agencies and GAAP should recognize SaaS license arrangements as a capital expenditure rather than an operating expense. This change would accelerate the adoption curve and accessibility of today's innovative computing models and unlock the scalability, elasticity, performance power, integration speeds, and cost benefits for utilities and their customers. The classification of SaaS as a capital expense would also reduce the current, unnecessary barriers towards technology advancement in the utility industry, which is an essential step in the transformation to a smarter, more efficient, and more sustainable energy system.

ABOUT THE AUTHOR

Ed Abbo is President and Chief Technology Officer at C3 Energy, which provides smart grid analytics SaaS/PaaS solutions that enable utilities to realize the full promise of their investments in the smart grid. He was formerly Senior Vice President at Oracle Corporation responsible for Oracle's application and SaaS products including CRM, ERP, and Supply Chain products. Prior to joining Oracle in 2006, he was Senior Vice President of Technology and Chief Technology Officer for Siebel Systems. Abbo earned an M.S. degree in Mechanical Engineering from the Massachusetts Institute of Technology and a B.S. degree in Mechanical & Aerospace Engineering from Princeton University.

With William T. (Tim) Shaw
PhD, CISSP / CIEH / CPT

SECURITY SESSIONS

Modbus and GETAC and Conitel. Oh my!!

Serial communications have been used in industrial automation for many decades, particularly starting in the early 1960s with the invention of integrated circuits and accelerating when (relatively) low-cost 16-bit 'minicomputers' with RS-232 communication boards became available. All long-distance communications (e.g. telemetry applications) relied on serial communications but even in-plant applications abounded once we had a lot of smart devices that needed to exchange data and commands. 'Serial' communications eventually morphed into LAN/WAN communications with the invention of Ethernet. And today we understand that LAN/WAN connectivity poses a cyber threat to our automation systems. But what about old-style serial communications? Are they a cyber threat?

I am constantly amazed at how conventional industrial 'serial' communications are misunderstood by IT and cyber security experts. Let me clarify; by 'serial' communications I mean low speed (300 bits/sec to 128 kilobits/sec), asynchronous, message exchanges based on bit/byte-oriented industrial protocols devised long before the invention of modern LAN/WAN technology and TCP/IP networking. I am talking about the kinds of communications used in prior generations of SCADA systems to communicate with field-based RTUs (remote terminal units) and even in early PLC factory-automation applications. A common theme among most such serial communication schemes was the need for low overhead (percentage of bits being transmitted that were 'data' versus the percentage of bits that were used to deliver the 'data'), a small population of participating devices (between two and sixteen) and reliable operation over low quality communication channels. Such communications were usually of a point-to-point or a point-to-multipoint configuration, with no need for message passing or routing due to the 'flat' architecture of the communication channel.

As there were no standards for industrial communications in the 1960s and 1970s each manufacturer of smart devices, PLCs and SCADA systems tended to devise their own, proprietary protocol(s). Between the invention of the IC and their use in building low(er)-cost computers there was a period of time where digital devices such as MTUs (master terminal units) and 'dumb' RTUs were designed and built, with their communication protocol logic actually hard-coded in digital circuitry. Those devices tended to use isonchronous (bit-oriented) communications where the messages were composed of a potentially large number of bits (not always a multiple of 8) and transmitted sequentially without breaking the message into octets and appending start/stop bits (as in asynchronous transmission). When computers came along and had to communicate with those 'dumb' (digital but not computer-based) RTUs special communication hardware had to be developed to send and receive the isonchronous messages. Legacy protocols such as CDC type I/II, Conitel, TRW and Getac were of this bit-oriented design (and named after the companies that devised them) and, surprisingly, most are still found being used in electrical substation and SCADA/EMS applications today.

As a former SCADA system developer I can attest to the major pain in the posterior that resulted when a customer required us to support any of these legacy protocols. You can't 'speak' to them using a conventional UART circuit (so forget the COM: ports on your PC). We had to develop special hardware circuitry to transmit/receive the entire isonchronous messages and then break them into octets that could subsequently be delivered using a UART circuit into a COM: port. This is a consideration when assessing the cyber vulnerability of such communications as no off-the-shelf computer hardware can be successfully used to eavesdrop on (or inject falsified) message traffic.

In the 1970s the UART chip and RS-232 electrical standard, combined with early telephone MODEMS, provided a means for dumb computer terminals (remember those?) to communicate asynchronously (character by character) with mainframe computers and form 'timesharing' computer systems. The industrial world picked up on the same technologies and thereafter most (but not all) subsequent industrial protocols used asynchronous message transmission. In that timeframe several new protocols were devised, both for early PLC applications and for electrical, pipeline, transportation and water SCADA applications. The Modbus and DNP protocols are good examples of asynchronous, serial protocols that could operate on low-speed channels (such as a radio link or analog phone line) and support both point-to-point and multipoint operations. Both of those protocols have been widely accepted and are in common use today in a wide range of industrial applications. In fact Modbus protocol is found in more smart devices (devices that support asynchronous serial communications) than any other industrial protocol.

Those protocols, and even the earlier bit-oriented ones, are not of the same sophistication as modern LAN/WAN protocols that use TCP/IP and use a layered design such as is described by the ISO/OSI (open systems interconnect) model. These serial industrial protocols consist of essentially just three (3) layers as compared to the seven (7) layers of the OSI model and the five (5) layers of the IP model. Those three layers are (using the OSI terminology) the 'physical' layer, the 'data link' layer and the 'application' layer. The layers that are missing involve functions such as routing and session persistence and data format compatibility. None of those functions were required by these industrial protocols. Another major difference between these industrial protocols and a general-purpose message delivery service like TCP/IP (or even UDP/IP) is that all of the allowable/supported commands and data types are pre-defined in the industrial protocol specification and anything else should/would be treated as a bad/invalid message and ignored.

Industrial protocols were/are, in general, designed to allow the exchange of data/status values and the issuance of control requests. In other words to allow for remote access to analog/pulse/status inputs (values) and remote manipulation (control) of analog/pulse/contact outputs. Different protocols use different means for specifying which inputs and outputs they are accessing and some support more data types than others (e.g. only discrete bits and 16-bit integers versus floating-point values). Different protocols offer a different variety of possible commands (e.g. merely read/write registers versus supporting accumulator freeze, setting the time/date, etc.). It is important to note that most smart devices that 'support' a given industrial protocol actually only support the minimum subset of defined commands necessary. For example, if a smart device has no control outputs why would the vendor waste time programming it to process output manipulation commands? Much less costly just to program-in the one or two commands needed by the device and treat all other commands as invalid (even if they are defined by the protocol specification.)

I have overheard long-winded arguments between so-called experts about how a Modbus serial communication connection between an RTU and a SCADA 'host' could be usurped by an adversary to launch a cyber attack on a SCADA system. It is quite feasible that an attacker could tap into a communication channel and inject falsified message traffic (Google Vitek Boden if you want to read about a real-world example of doing this.) If done as falsified responses to a SCADA host the result would be invalid measurement/status indications to the operators. If done as falsified commands to the RTUs then this could result in field equipment being put into unsafe conditions. Neither of those results are, in my humble opinion, a 'cyber attack' on the SCADA host. Neither effort will result in injecting malicious executable code into the host or provide the attacker with the ability to remotely control/manipulate the host. This is not to say that bad things might not happen, but it is still not a cyber attack in the traditional sense.

Of course with a SCADA system, unless the communications between the host and RTU were left broken by the attacker, at the next poll the invalid data would be replaced with fresh valid data and operators could issue commands to restore field equipment to its valid state. Also note that major SCADA systems usually have numerous communication channels out to the field and the RTUs, so disrupting just one channel would have a limited scope of impact. And really big SCADA systems often have backup sites with separate communication channels to the field in order to ensure that operations can be maintained.

Not too long ago a researcher claimed that there was a 'special message' they had devised that could crash any SCADA system that used Modbus protocol. In cyber security speak they were claiming to have devised an exploit and payload that if transmitted to the SCADA master as a response to a poll would result in killing the Modbus communication task at the host end (would result in a buffer overflow that mangled the Modbus driver instructions). They failed to take into account how real SCADA systems operate: most run a separate process for each communication channel and a separate background ('watchdog') process that watches over running processes and will reload/restart any that crash or get hung. Thus the results of the attack would be short-lived (actually since most SCADA systems are designed with redundancy it is possible that an automatic switch to the backup would occur to restore Modbus polling operations.)

Also, that particular exploit and payload might be viable for a very specific version of a Modbus driver from a given vendor, but many SCADA system vendors have written their own protocol libraries and it is unlikely that the exploit and payload would work against a different vendor's software. Certainly, if a vulnerability is discovered in a commercial protocol library (and many have been) then any SCADA system using that particular library/version would be potentially susceptible to attack and exploitation.

To date I have not been made aware of any cyber attack on an asynchronous serial communication polling channel that resulted in injecting malware or hacker-ware into a SCADA host. In theory it should be possible, and I would be very interested in learning about any successes in this regard. But so far the jury is out.

Now this is not to say that all serial communications are 'safe' and don't provide a potential cyber attack pathway. Any form of TCP/IP networking can potentially be abused through cyber manipulation. We should all remember that prior to the widespread availability of broadband networking most of us got to the Internet by using a dial-up phone line and a MODEM to connect to AOL (or some other ISP). So obviously a TCP/IP connection and session can be established over a low-speed, asynchronous, serial communication channel.

Also, serial communications have often been used for remote maintenance and technical support activities. If a technician is remotely accessing a protective relay in a substation using a dial-in phone line then it may be possible for an attacker to discover the same phone line and attempt to gain access to substation IEDs using a brute-force password cracking attack. That is something that an electric utility would definitely wish to prevent from happening, but that will have to be the subject matter for a future column.

ABOUT THE AUTHOR

Dr. Shaw is a Certified Information Systems Security Professional (CISSP), a Certified Ethical Hacker (CEH) a Certified Penetration Tester (CPT) and has been active in designing and installing industrial automation for more than 35 years. He is the author of *Computer Control of BATCH Processes* and *CYBERSECURITY for SCADA Systems* and co-author of the latest revision of *Industrial Data Communications*. Shaw is a prolific writer of papers and articles on a wide range of technical topics and has also contributed to several other books. Shaw has also developed, and is also an instructor for, a number of ISA courses and he also teaches on-line courses for the University of Kansas continuing education program. He is currently Principal & Senior Consultant for Cyber SECurity Consulting, a consultancy practice focused on industrial automation cyber security and technologies. Inquiries, comments or questions regarding the contents of this column and/or other security-related topics can be emailed to timshaw4@verizon.net.

San Bernard Electric Installs Advanced Data Exchange Part II

Guest Editorial

By Doug Lambert and Dominic Geraghty

In an earlier edition of EET&D (November-December 2014), we looked at San Bernard Electric Cooperative's (SBEC's) installation of MultiSpeak specification including a metering system, an outage management system (OMS), a customer information system (CIS), and a geographic information system (GIS). Topics covered a company overview, the business challenge, and solution description.

Analytics and alarms using OMS and field viewer

When SBEC first implemented the MultiSpeak specification between the AMI system and the OMS, its system operators were receiving alarms posting as outages on the OMS. Obviously, this sort of reporting pattern is not desirable. Data has to be delivered and presented to the dispatcher in the right manner every time or the dispatcher will experience overload, lose trust in the systems, and begin to second-guess the meaning of the data.

The irregular reporting between the AMI and OMS system was caused by untested, purported interoperability between the vendors' systems. The AMI vendor was quick to act and correct the problem by setting the meter alarms/meter events as 'no response' (NR), in the MultiSpeak message payload. However, the OMS system was unable to digest NR data. That is, OMS did not have anywhere to put such data since it was not setup to receive this data. This left utility operations personnel unable to see the alarms, which was unacceptable, particularly in light of the fact that the alarms feature factored into the decision to choose this particular AMI technology. The solution required customized code.

The smart meters of SBEC's AMI system can send many types of different alarms. The following list provides examples of the alarms that the AMI meters can provide to operators:

- **Power Fail** – MultiSpeak Outage
- **Tamper** – MultiSpeak Outage
- **Brownout** – temporary low voltage
- **ReadFail** – Unable to read meter
- **Hot Socket** – Fire is imminent
- **Low Volts** – sustained, under-threshold voltage for a period of time
- **High Current** – temporary current overload
- **Meter Power Fail** – MultiSpeak Outage
- **Reverse Power** – Generator present?
- **High Voltage** – temporary above the voltage threshold
- **Disconnect Fail** – Unknown disconnect state, which could be serious, e.g., a meter fire

Some of the alarm data was transmitted correctly from the AMI system to the OMS for the utility's MultiSpeak Version 3.0. In instances where the data was not transferred correctly, the utility's IT staff developed customized integration code.

The AMI vendor was using an SQL database. First, the utility's database expert had to identify which tables were storing the alarms. Then, the behavior of the AMI system and the significance of each alarm had to be determined.

For the OMS, the database tables and interrelationships had to be understood well enough to update the correct tables with SQL commands in order to display the desired results in the OMS in a usable manner. This took the cooperation of each vendor, expertise in using SQL, access to the right tables in the right sequence, and a patient group of employees. IT personnel had to explain the different alarms to the dispatchers so that they could take appropriate action in response.

Sometimes, more information does not improve situational awareness. For instance, the operators were seeing brownout alarms (low-voltage events) with almost every outage. During a lightning storm, the dispatchers' OMS screen would be covered with brownout alarms that were simply dismissed as being related to an outage. In response, the dispatchers turned off the brown-out alarms. That also meant, however, that the utility would not be archiving those alarms when they weren't related to an outage – an undesirable outcome. Figure 3 shows an alarms screen presented by SBEC's Sensus software. It does not alert anyone when a new alarm occurs. This is true for all alarms using the software package SBEC chose. Sensus has since developed software for specifically dealing with alarms

San Bernard Electric Installs Advanced Data Exchange - Part II

Sifting through all of the alarms in the AMI system manually was too complicated and time-consuming. All of this interpretation would be left to the IT experts to analyze. (What if the customized code missed something that was important?)

Instead, the programmer wrote SQL code to look at the alarm view in the Sensus AMI database and present a brown-out alarm as a note on the screen. Each note simultaneously received an expiration date and time.

As part of the custom coding, the dispatcher receives an audible alarm as well as a symbol on the meter in the connectivity model within the OMS.

Another example of a customized code fix was related to providing an alarm when a voltage regulator malfunctions. In the screenshot example below (Figure 1), a view of alarms on an outage map (with custom SQL code integration), the dispatcher received all of the alarms shown in green at the same time. They were all high voltage alarms, all on the same phase (A phase) and all down-line from a regulator on the circuit connectivity model.

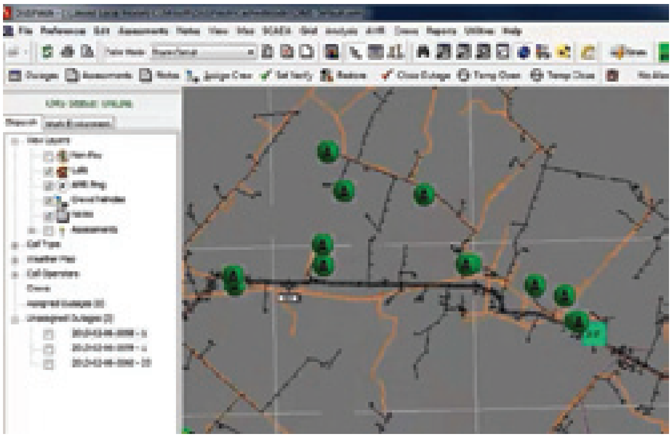


Figure 1: View of alarms on an outage map (with custom SQL code integration)

A crew was dispatched to the regulator where they discovered that the regulator controller had indeed malfunctioned and was outputting high voltage. The regulator was taken off-line and the problem was corrected. Less than an hour passed from the moment that the alarms were received until the problem was corrected. No customer phone calls were received.

Just a few months prior to implementing this system integration, SBEC experienced a similar incident. The utility was not aware of a high voltage issue until it received phone calls from its members. Once the source of the problem was identified as faulty equipment on the utility's power line, SBEC received multiple insurance claims which it had to pay. If the MultiSpeak specification had been in use, its alarm system would have prevented such a development.

This example underscores that an investment in the smart grid and in interoperability of typically disparate systems provides a tangible return on investment

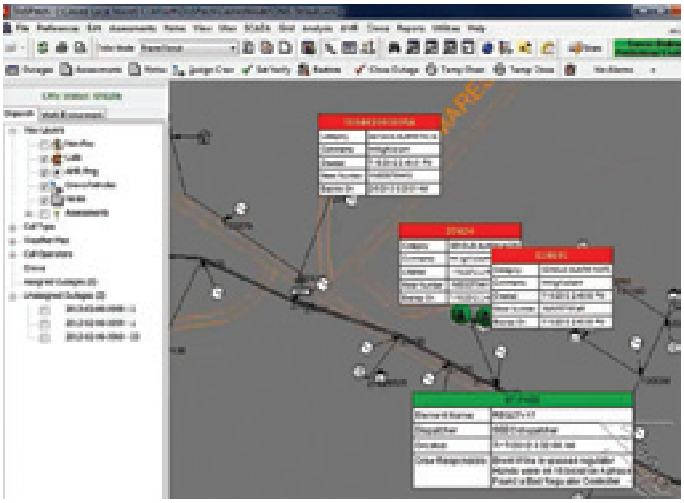


Figure 2 - After custom SQL code integration: the dispatcher's view of alarms on an outage map

Figure 2 presents the customized screen shot of the high voltage alarms after the customized SQL code integration. Once the alarm is dealt with, it is closed and becomes a permanent historical record on that meter location. Data collection showing the source of alarms is very helpful in determining the number of times a particular location has produced an alarm – either by a human phone call, IVR call or by a meter signal. The utility's basic AMI system is set up to keep only 60 days of history. Therefore, another system is needed for storing a record of all the alarms to facilitate ensuing analytics. In SBEC's case, the utility stored these alarms in the OMS (see Figure 3).

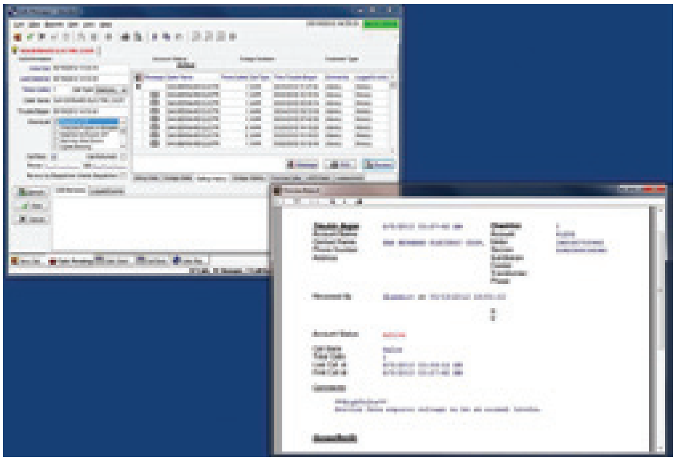


Figure 3: A permanent historical record is made of all alarms, outages, and phone calls at a particular location

Figure 4 illustrates the view of a dispatcher receiving a 'Hot Socket' alarm. In this case, the service crew was on the scene within 20 minutes of receiving the alarm. The crew reported the meter to be too hot to touch. There was a short in the underground service entrance below the meter. The meter was red-tagged as a hazard. The member was notified and a potential structure fire was prevented.

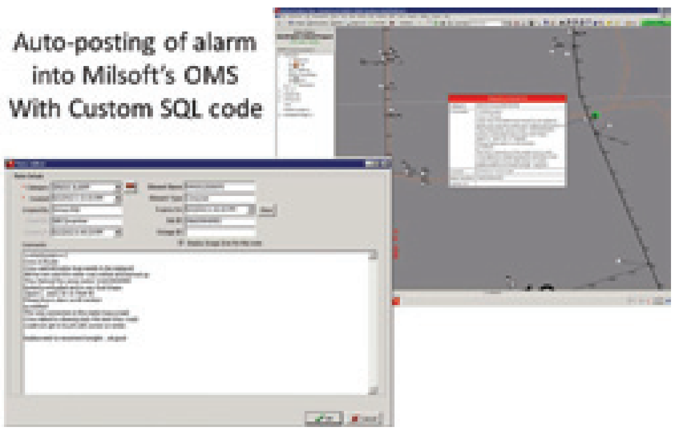


Figure 4: Dispatcher receives a 'Hot Socket' alarm

Not all alarms need to be dealt with by dispatch. For certain types of alarms (ReadFail, e.g.), SBEC wrote additional code that displays the alarms in the field viewer – these are designated as 'Unplugged' (see Figure 5).

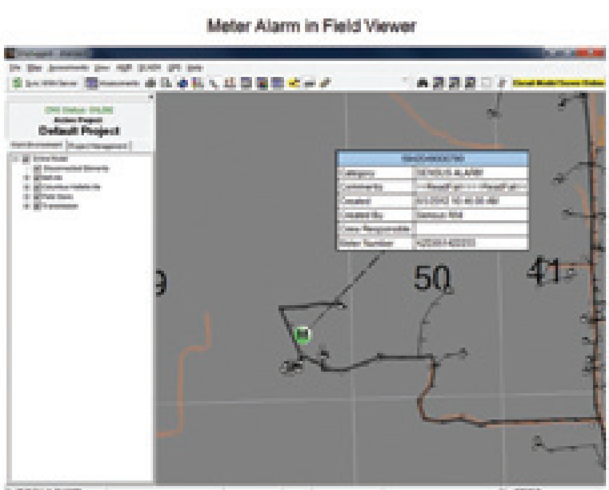


Figure 5: An alarm indicates that a meter has failed to provide a read at a designated time

The software also sends an e-mail to the responsible parties to alert them to the 'ReadFail' alarm so that it can be dealt with accordingly (see Figure 6). Before using the MultiSpeak specification, these kinds of problems were not known until a problem appeared with the readings in the utility's billing department, which might occur as long as a month after the problem transpired. Since the MultiSpeak implementation, the utility knows about a 'ReadFail' alarm within minutes and it can be resolved before it becomes a billing-related issue.

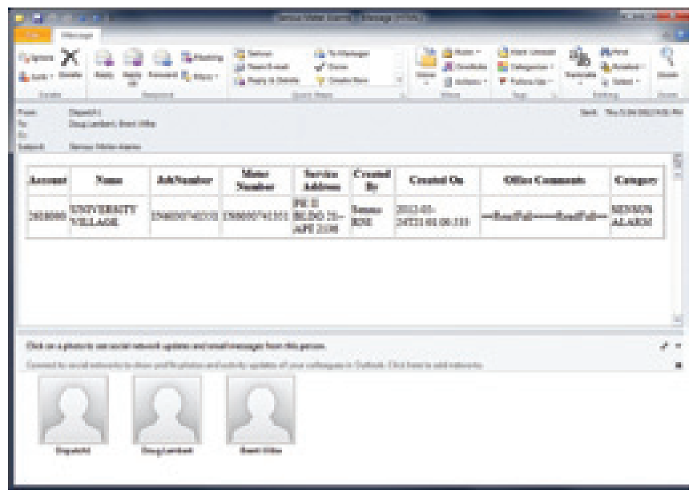


Figure 6: Automated notification of a 'ReadFail' alarm

In summary, SBEC wrote additional customized code to classify AMI alarms as part of AMI alarm integration with the OMS. Examples of those alarms included malfunctioning voltage regulator controls that could result in high voltage-damage to SBEC members' equipment and result in insurance claims; malfunctioning transformers that fail to provide American National Standards Institute (ANSI)-compliant voltage to member's residences and hot sockets that could cause a fire.

Interoperability-related lessons learned from SBEC's Implementation

The lessons learned from SBEC's MultiSpeak implementation (Specification Version 3.0) were many.

Careful attention must be paid to software issues relating to iterative versions. Just because a vendor is MultiSpeak compliant doesn't mean that the vendor's system can integrate seamlessly with MultiSpeak-compliant systems the utility already has in place. Different vendors may be running different versions, so it is important to understand the capabilities and limitations of the version of the specification that your vendor is supporting – especially as versions are not backwards compatible.

San Bernard Electric Installs Advanced Data Exchange - Part II

Further, methods needed to accomplish a business process may not be supported by the vendor. Be aware that software packages may include fixes written by 'rogue' software writers. Although those fixes may have been written to integrate with utility-specific methods, they may misinterpret the purpose of a method and/or fail to follow the standard. When MultiSpeak Version 3.0 was used to integrate SBEC's OMS and AMI systems, the utility discovered that it did not specify how to handle transmitting meter alarms to the OMS. Since SBEC's implementation, a newer version of the MultiSpeak specification, version 4.1, now has the capability to address meter alarms and AMI system and OMS vendors are now writing to the new version. Additionally, a version transition strategy is being developed for SBEC by its vendors which will avoid loss of data, downtime, and functionality.

Generally speaking, custom integrations are to be avoided, for several basic reasons. First, for example, the programmer who develops the customized interface may leave the utility and no one else will understand the implementation. Second, it is much better to have the utility specify its interoperability requirements to the vendors as part of the procurement process. Third, it is not good risk management practice to have someone other than the vendor access the databases of complex software because such access could negatively impact a utility's mission-critical business processes by undermining certain core functionalities of the software.

General recommendations to industry

Before implementing major integration processes, the implementation team needs to identify and understand the utility's methods and the correlated business processes and functions that these methods are expected to support. Mapping data transport from source to value creation sounds obvious, but there's no substitute for mastery of the details in this context.

A utility procuring the MultiSpeak specification should require that prospective vendors be active participants in development activities. This requirement should be included in request for proposals (RFPs) as well as in awarded contracts.

Interoperability should be defined in broad terms. A particular version of software should not be specified. Instead, procurement requirements should focus on the business processes that need to be supported and integrated.

The burden for staying compliant, up to date, and functioning in an interoperable manner should be placed on the vendors. This requirement should also be included in service level and maintenance agreements with vendors. In fact, testing regimes need to be improved. Testing is invaluable to vendors and utilities to ensure interoperability and provide confidence to the end user that systems and devices will integrate and interoperate. Similarly, interoperability testing between vendors should be required before signing contracts and interoperability affirmation/assertion documentation should also be required to prove that the testing has been successfully completed.

But documentation is not sufficient. The procuring utility needs to study the methods within the interoperability affirmation/ assertion documentation to ensure that the testing employed addresses their required business functions. If pertinent methods are being omitted in the testing, the utility needs to question why and insist on a commitment from the vendors to include those methods in follow-up testing.

Finally, interoperability testing between utility systems should be required as part of system-acceptance testing. This requirement should always be explicit in the contract. If there are methods that one or multiple vendors are not supporting in the future, but the methods are available in the current supported versions and the utility needs the methods for its business processes, it needs to get a hard commitment from all vendors that they will add those methods to the versions they are offering.

ABOUT THE AUTHOR

Doug Lambert is the Senior Principle of Distribution Engineering and System Automation with the National Rural Cooperative Association, an organization of more than 900 not-for-profit rural electric cooperatives and public power districts providing retail electric service to more than 42 million consumers. Previously, Doug worked with the San Bernard Electric Cooperative in Texas for 15 years as an IT manager and SCADA and engineering data supervisor, among other roles.

Dominic Geraghty is a senior consultant with the Smart Grid Interoperability Panel, a member-funded organization that engages Smart Grid stakeholders to create national standards and advance interoperability, Dominic has spent over 20 years working to advance the grid. He has been a general partner at a venture capital fund and worked in a large private equity fund, both focused solely on energy deals. He currently serves as managing editor of SmartGridiX and as executive chairman of both Smart Energy Instruments and N-Dimension Solutions.

ADVERTISERS INDEX

COMPANY	WEB SITE	PAGE
Advanced Control Systems, Inc.	www.acspower.com	11
Cantega Technologies Inc.	www.cantega.com	5
Cired 2015	www.cired2015.org	Inside Back Cover
ComNet Communication Networks	www.comnet.net	21
Doble Engineering Co.	www.doble.com	7
Doble Engineering Co.	www.doble.com	Supplement 6 - 7
Hastings Fiberglass Products Inc.	www.hfgp.com	3 - 44
Hubbell Power Systems Inc.	www.hubbellpowersystems.com	9
Inner-Tite Corp	www.inner-tite.com	39
Lockheed Martin	www.lockheedmartin.com	22 - 23
Lockheed Martin	www.lockheedmartin.com	Supplement 5
Mersen Canada Toronto Inc.	www.ep-ca.mersen.com	44
Morgan Schaffer	www.morganschaffer.com	14-15
OMICRON electronics	www.omicronusa.com	28
Open Systems International	www.osii.com	Back Cover
Prolec GE Internacional, S. DE R.L. DE C.V.	www.prolecge.com	Inside Front Cover
Systems With Intelligence Inc.	www.SystemsWithIntelligence.com	1
WIRE Services	www.wireservices.ca	30