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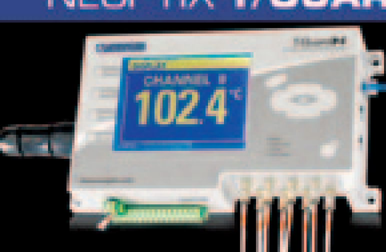

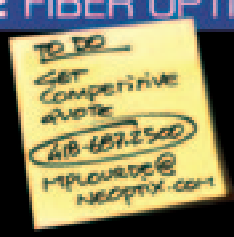


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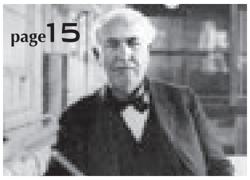
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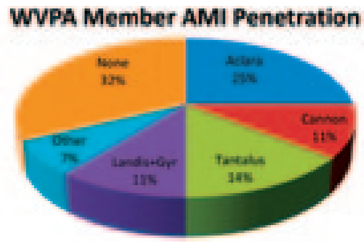

Publisher:
Steven Desrochers: steven@electricenergyonline.com

Editor in Chief:
Mike Marullo: mam@electricenergyonline.com

Contributing Editors
William T. (TIm) Shaw, PhD, CISSP
tim@electricenergyonline.com
Gregory K. Lawrence, Partner; McDermott Will & Emery LLP
glawrence@mwe.com

Advertising Sales Manager:
Jimmy Desjardins: jimmy@electricenergyonline.com

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

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

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Web: www.electricenergyonline.com

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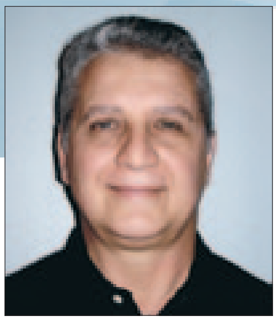
Michael A. Marullo, Editor in Chief



2010: Can Butterflies in Brazil set off a Tornado in Texas?

The beginning of a new year usually means a new start for lot of things, and if ever we needed a new start, this is probably a good time for it. When I think about last year compared to the coming year now upon us, I find it much more difficult than usual to plot the curve... the shape of things to come, if you will. Not that I'm one who tries to predict the future by looking at the past – it goes against my grain as a market research professional – but there's usually a better defined thread of continuity between years than I can readily discern in these most unusual times.

Why is that, I wondered; what's so different this time around? Well, I think part of it is because the recession we're still suffering from actually started almost a year before being acknowledged by those who are supposed to keep track of such things. Indeed, even though the signs were there and many of us knew or strongly suspected it, the official proclamation wasn't made until the end of 2008. Until then, I believe we were operating under what many of us thought – but couldn't really prove – was a false sense of economic equilibrium. As a result, we're now entering the third year of what feels like a completely random pattern. At this point, "Chaos Theory" comes to mind.

For those who may not be familiar with the fundamental concept of Chaos Theory, it comes from the fact that the systems it describes are apparently disordered, but the theory is really about finding the underlying order in what appears to be random data. The first true experimenter in Chaos Theory was Edward Lorenz, a meteorologist who was working on the problem of weather prediction in the 1960s. He had a computer set up with twelve equations to model the weather. Although it didn't predict the weather itself, his computer program did *theoretically* predict what the weather *might be*.

In more technical terms, Chaos Theory is the study of nonlinear dynamics, where seemingly random events are actually predictable from simple deterministic equations. The two main components of Chaos Theory are: 1) The idea that systems – no matter how complex they may be – rely upon an underlying order, and 2) that very simple or small systems and events can cause very complex behaviors or events.

To illustrate these points, Lorenz first described something called the "butterfly effect" at a meeting of the American Association for the Advancement of Science in Washington, DC in 1972. In a 1963 paper for the New York Academy of Sciences, Lorenz had quoted an unnamed meteorologist's assertion that, "...if Chaos Theory were true, a single flap of a single seagull's wings would be enough to change the course of all future weather systems on the earth."

By the time of the 1972 meeting, he had examined and refined that idea for his talk, *"Predictability: Does the Flap of a Butterfly's Wings in Brazil set off a Tornado in Texas?"* The example of such a small system as a butterfly being responsible for creating such a large and distant system as a tornado in Texas illustrates the impossibility of making predictions for complex systems. And, despite the fact that these effects are determined by underlying conditions, precisely what those conditions are can never be sufficiently articulated to allow long-range predictions.

So what does this all have to do with the outlook for 2010? Well, first of all, I think we can all agree that the outlook has been pretty fuzzy – okay, downright erratic – for most of 2009. And now that we're into a new year, it doesn't seem to be much better – let's just say uncertain, at best. But amid all of this apparent chaos, I do believe it's possible to pull a few examples of cause and effect out of the morass of technical, financial and political issues and trends.

GRIDLINES

Michael A. Marullo, Editor in Chief

It's not too hard to see why the pace of business slowed toward the end of last year when the recession had been in full force for nearly two years. Yet although most businesses were practicing the belt-tightening that one would expect, I don't know that most people really had any idea just how bad it was – or how long it was going to be before it would get better.

Then, as bad news mounted and the American Recovery and Reinvestment Act (aka Stimulus Bill) became a reality, there was a rather bizarre mix of optimism and pessimism toward the end of the year. This was a most peculiar circumstance, since it's usually one way or the other, but not both.

I suppose one explanation was a pervasive feeling that although we had a big problem help was on the way, but we know now it isn't going to be that simple. Moreover, the stark realization that the Stimulus Bill wasn't going to be a panacea struck yet another blow to what we had all hoped would be a fairly quick recovery.

The fact is, not only did the Stimulus Bill not have an immediately positive impact; it actually had quite the opposite. That is, once it became apparent that there might be a way to obtain Stimulus funding for a wide range of expensive infrastructure projects, many of those same projects were immediately put on hold or canceled altogether – not exactly the outcome anybody wanted to see in the midst of an already severe business downturn. Even so, some critical projects still moved forward, lending a modicum of stability to a severely weakened economy – yet another anomaly in an increasingly unpredictable period.

So, how to make sense of all this? Perhaps "sense" isn't the right word, but for what it's worth, here's how I see the outlook:

1. Don't expect the downturn to end anytime soon – probably not before mid-year at best. That's because it's one thing to announce Stimulus funding and make the awards; it's quite another to actually have those funds in hand. Speaking from our own post-Katrina recovery here in the Gulf Coast Region, we learned first hand that the wheels of government turn slowly. And although I do believe that positive steps are being taken to move things along as quickly as possible, I'm guessing that the money probably won't be available as fast as most people think.
2. Job recovery is still a huge problem and will continue to be for a while yet. The problem is that you can't have job recovery until you stem job losses, and even though the latter is happening at a fairly good clip, we haven't turned the corner yet because we're in a very deep hole that we have to dig our way out of first.
3. But wait... the news isn't all bad. I firmly believe that anytime you throw three quarters of a trillion dollars at something, it's bound to leave a mark – a big one. However, it's still way too soon to see it (refer to #1 and #2 above), so those who are saying the Stimulus isn't working are just ahead of the reasonability curve. There's a certain incubation period that cannot be shortened or avoided, so I'm afraid we'll just have to be patient a bit longer. Will there be waste and inefficiencies? You bet there will, but with that much money involved, I predict that there WILL be projects and there WILL be jobs – lots of both.

So rather than looking for direct correlations, patterns and trends, I've decided to put my faith in Chaos Theory and assume that there really is some rhyme and reason to all of this, even if it may not be immediately apparent. And let's hope that those butterflies flapping their wings do set off a tornado – an economic one. – ***Ed.***

Industry News

AES Eletropaulo and New Fault Indication System Reduce Utility's Underground Fault-Finding Time by 40 Percent

PULLMAN, WA—January 13, 2010—Brazil's largest utility, AES Eletropaulo, reduced fault-finding time on its underground distribution system by nearly 40 percent with a fault indication system manufactured by Schweitzer Engineering Laboratories (SEL). Before the introduction of the fault indicators, utility crews worked 19 hours on average to locate and repair faults on network underground feeders; today, they work 12 hours. AES Eletropaulo also observed a 60 percent reduction in the number of inspection manholes to open when searching for faults.

The utility's underground distribution system, concentrated in São Paulo's central region, has 8 substations and 75 varying high-voltage feeders. It also has over 2,800 kilometers of primary and secondary cables, more than 4,000 inspection manholes, and about 4,300 transformer vaults.

Maintenance crews previously located feeder faults by opening many vaults unnecessarily to pinpoint the affected feeder section, requiring comprehensive safety measures for poor or hazardous ventilation, flooding, and other risks. To find the exact fault point, linemen performed "thumping," or connecting equipment to and running a large charge through a high-voltage underground cable, causing it to move. The technicians above ground listened to the moving cable's vibration to determine the fault location.

AES Eletropaulo began working with SEL to improve system fault finding in 2008. SEL engineers helped AES Eletropaulo install a customized wireless fault indication system with underground fault indicators on the utility's feeders. Now operators remotely monitor the feeders for faults from the substation, send maintenance teams directly to the cable section, and make repairs without opening multiple vaults or exposing workers needlessly to dangerous current.

"This was fundamental for the success of the project, in addition to the training and availability of the SEL team, which provided support and clarifications on issues that arose after the implementation," said Ricardo de Oliveira Brandão, an engineer with the Underground System Management Administration – PGDCG (North Regional Board).

AES Eletropaulo will install more of the SEL wireless fault indication systems throughout its system this year to continue with fault detection improvements. For more information, visit *www.eletropaulo.com.br*.

For more information, visit *www.selinc.com*.

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Arqiva to Employ Sensus Smart Grid Technologies for UK Utilities

Partnership enables Arqiva to deliver smart meter solutions for businesses and homes

Raleigh, NC (December 1, 2009) – Sensus, a leader in intelligent solutions for gas, water and electric utilities, and Arqiva, a UK-based communications infrastructure and services company, have formed a partnership that will enable Arqiva to implement a long range radio-based communications platform for the UK's utility companies. Using the Sensus FlexNet™ and SmartPoint™ technologies for smart metering, telemetry, and control of the utility assets, Arqiva will deploy a communications platform as part of the UK's rollout of smart meters to all homes and businesses.

"The blend of Sensus' smart metering experience in the North American market and Arqiva's experience with critical network infrastructure in the UK represents an exciting proposition for the UK's smart metering initiative," says Bill Yeates, executive vice president, Conservation Solutions at Sensus. "Sensus is already playing a key role in the largest modernization of utility networks in the USA and Canada and we're excited by the prospect of helping the UK to achieve its energy modernization ambitions," he added.

The Sensus FlexNet smart grid communications system and SmartPoint technologies are being used by 200 electric, water, and gas utility customers in North America that collectively, have already deployed more than four million smart meters.

Industry NEWS

"With the Government's commitment to put smart meters in all homes by 2020, we have the opportunity to make the UK one of the most advanced and efficient consumers of energy in the world. For what will become a critical piece of national infrastructure, we must make sure that we set the bar high with the proposed central communications network. This means not only universal coverage but resilience, security, and availability, something that long range radio has proven it can deliver through the UK's broadcast network," says John Cronin, managing director, Arqiva Wireless Access.

The solution being developed by Arqiva, which is based on long range radio technology, will operate in available UHF spectrum and builds on the company's experience in operating the UK's terrestrial TV and radio broadcast network. The communications platform will offer multiple benefits, including:

- Dedicated, secure network – Arqiva will use its dedicated UHF spectrum, combined with Sensus' purpose designed security measures, to provide a bespoke communications network for independent use by the UK's water, gas and electric utilities.
- Proven technology – Sensus is the leading North American provider of long range radio smart metering solutions. The Sensus FlexNet™ smart grid communications technology has been proven at scale, with more than four million smart endpoints already deployed.
- Universal UK coverage with minimal infrastructure – A long range radio network offers significant geographical coverage with minimum infrastructure; Arqiva already delivers terrestrial radio and TV services to 98.5% of the UK using a similar solution.
- Simple and cost-effective smart meter roll-out – Long range radio signals carry extremely well through buildings, even underground, reaching meters situated in cupboards or cellars that would be out of range of other communications technologies, thus avoiding the cost of moving and reconnecting meters.
- High capacity and scalable – Long range radio has the necessary capacity to meet the smart energy initiatives for meters and grid networks as well as scalability for other utilities, such as gas and water.

The partnership allows Arqiva to focus on the development of the long range radio-based solution for the single centralized national communications network as recommended by the Department of Energy and Climate Change (DECC) in its smart metering consultation paper issued earlier this year. Arqiva will begin technology trials in December 2009.

Circle **20** on Reader Service Card

GE Energy's John D. McDonald to Chair Smart Grid Standards Organization

U.S. Commerce Department's Panel will Oversee Development of Vital Interoperability Standards for a more Efficient and Reliable Power Grid

John D. McDonald, general manager of marketing for GE's (NYSE: GE) transmission and distribution business has been selected to head the Commerce Department's National Institute of Standards and Technology's Smart Grid Interoperability Panel Governing Board (SGIPGB). The unanimous choice of governing board members, McDonald will leverage his decades of grid automation experience to help organize the group's agenda and activities. He also will serve as the board's chief spokesperson.

"Since I've been working my entire career to build a smarter grid, I am thrilled with the opportunities I can help uncover as chair of an initiative that is vital to our energy future," McDonald said. "I'm invigorated by the challenge of helping so many committed energy industry leaders work together to frame the infrastructure that will power our planet for generations to come. Defining our standards will hasten the development of ever-improving solutions and help American innovation set the worldwide standard for Smart Grid efficiency, reliability and performance."

The National Institute of Standards Development established the SGIP to handle its smart grid responsibilities under the 2007 Energy and Independence Security Act. Today, more than 450 participating and observing member organizations are working together to address technical issues and help determine standards to optimize the reliability, efficiency, security and interoperability of a modernized electric delivery system across America.

McDonald is uniquely qualified to serve as the Board's first-ever chair, with decades of electrical industry leadership, engineering expertise and extensive board experience for various leading energy industry groups and governance organizations. His term will run for two years.

The SGIP Governing Board is elected by representatives of SGIP's 400-plus participating-member organizations.

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Industry NEWS

Hydro-Québec and Mitsubishi to launch the largest electric vehicle trial in Canada -

up to 50 Mitsubishi i MiEV electric vehicles to be tested in Boucherville

Montréal, Québec - Hydro-Québec and Mitsubishi Motor Sales of Canada Inc. (MMSCAN) announced on January 14 the signature of a memorandum of understanding that will lead to the launch of Canada's largest all-electric vehicle pilot project this coming fall.

In collaboration with the City of Boucherville, Hydro-Québec will test the performance of up to 50 all-electric Mitsubishi i MiEVs on the road under a variety of circumstances, notably winter conditions. The project, which is evaluated at $4.5 million, is the first of its kind to include the participation of a car manufacturer, a public utility, a municipality and local businesses that will integrate the vehicles into their existing fleets. The trial is designed to study the vehicles' charging behavior, the driving experience and overall driver satisfaction.

"This new pilot project is part of our action plan for the electrification of vehicles," noted Thierry Vandal, Hydro-Québec's President and CEO. "It will allow us to advance our knowledge of the technology and its integration into our grid, which in turn, will help us plan the necessary charging infrastructure for homes, offices and public places."

The City of Boucherville was selected as the project's host municipality given its proximity to Hydro-Québec's research institute (IREQ), its role in Hydro-Québec's upcoming interactive smart zone trial and the diversity of its local businesses. The availability of a local Mitsubishi dealership to oversee the i-MiEVs' maintenance was also part of the selection criteria.

"This is a truly exciting project for the City of Boucherville. We hope it will have a positive impact on our industrial sector and we look forward to working with our local businesses to help Hydro-Québec and Mitsubishi gather meaningful data," said Jean Martel, mayor of Boucherville.

i-MiEV, which stands for Mitsubishi Innovative Electric Vehicle, is an all-electric, highway-capable, charge-at-home commuter car. Because the battery, the motor and other items are mounted out of the way beneath the floor, the i-MiEV seats four adults and offers surprising interior room and cargo space. Other i-MiEV features include excellent low-speed acceleration and a very low centre of gravity, which contributes to superior handling and stability. Moreover, the i MiEV is extremely quiet.

"We are very proud to be leading the way to a greener, more sustainable future by developing environment-friendly vehicles fueled by clean, renewable energy," said Koji Soga, President and CEO of MMSCAN. "Mitsubishi is a leader in electric car development and the i-MiEV represents the pinnacle of our green technologies. In the same sense, Hydro-Québec and the City of Boucherville are demonstrating their environmental leadership by participating in this unique initiative."

At the recent Tokyo International Motor Show (2009), the i MiEV won the Japanese Car of the Year award for "Most Advanced Technology."

For further information, visit *www.mitsubishi-motors-pr.ca* or *www.hydroquebec.com/electrification-transport*.

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UtiliCon Solutions, Ltd., an Asplundh company, acquires Highlines Construction Company, Inc.

Philadelphia - UtiliCon Solutions, Ltd., a subsidiary of Asplundh Tree Expert Co., announced on December 29, 2009 the purchase of certain assets of Highlines Construction Company, Inc. based in Westwego, Louisiana. Highlines, founded in 1969, provides electric transmission, substation and distribution system construction, maintenance, street lighting and related services in the southern United States.

Bryan Beadle, former vice president of Highlines, will have operational responsibility for the Highlines organization and will report to Greg Holman, Vice President of UtiliCon Solutions. Beadle said, "I'm looking forward to continuing to provide outstanding service to all Highlines customers and to future growth opportunities with help from the considerable resources that UtiliCon can offer."

George Graham, President of Utilicon Solutions, said, "We are very pleased to be adding Highlines to the UtiliCon family of companies. With Highlines' strong operational performance, safety culture, management team and utility experience, they will bolster our existing construction presence in the South. I welcome the Highlines employees who joined our team and look forward to a very successful 2010 and beyond."

Visit *www.utiliconltd.com* for more information.

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GUEST EDITORIAL

Beware The Smart Grid Cliff / By Jon T. Brock, President, Desert Sky Group, LLC

To set the stage for what follows, you'll need to travel back a decade with me to December of 1999. I'm busy doing last minute shopping for Christmas presents and preparing to stay up all night on December 31st, ready to go into work if the "big blackout" comes as a result of Y2K (the date switching from 1999 to 2000 in countless systems). I'm working at one of North America's largest electric utilities, and no blackout occurs. My thoughts quickly turn to the analysts who in January of 2000 proclaim that bricks-and-mortar have once again outsold the "dot-coms" for the 1999 Christmas buying season. Then, March 10, 2000 brings the peak of dot-coms being over-valued, and the NASDAQ hits 5132.52 – just before the collapse. So is the Smart Grid following the same path as the dot coms? Considering the way it's being characterized at the moment, I believe so…

Just as the dot-coms were over-hyped in the late nineties and eventually came to fulfill their promise in the mid-2000s, I'm of the opinion that like the dot-coms, grid transformation will very likely fall short of expectations for the near term, but will probably be better equipped to deliver on those promises over the longer term, the latter being several years – certainly not one or two.

According to IT analysts at renowned Gartner Group, Smart Grid technologies serving the utility industry are nearing the peak of their "hype cycle." The hype cycle is a process that Gartner says every technology goes through. Developed in 1995, the hype cycle consists of five areas: On the Rise; At the Peak; Sliding into the Trough; Climbing the Slope; and Entering the Plateau.

As Gartner sees it, technology hype cycles provide a snapshot of core technologies, software and infrastructure. Examples include topics in wireless, security, productivity tools, hardware infrastructure and networking. Gartner's "Emerging Trends & Technologies Hype Cycle" provides a view of highly hyped and high-impact trends and technologies from across the information technology landscape. Smart Grid technologies for the utility industry are nearing the peak, preparing to "slide into the trough," according to Gartner.

To illustrate the point, for the past three months I've posted a single question on my website, asking: "Is the Smart Grid over-hyped?" Although by no means is this poll scientific, 87% of respondents answered "yes." Would a more scientific approach yield different results? Perhaps, but I think not.

Joining the previously mentioned dot-com collapse are other examples including broadband fiber in the telecommunications markets; utility deregulated retail markets in North America; and even renewable technologies, to an extent. So, if we have history as a teacher on our side and we know that a specific segment of the market (in this case the Smart Grid) is over-hyped, then why are we running like lemmings toward a cliff we know exists? Or DO we know it exists?

I would agree that it's patently unfair to lump multiple technologies into a single basket called "Smart Grid," so let's take a closer look at them at the very highest level for starters. The United States Department of Energy provides a good definitional overview of the electrical grid. DOE states that the electric grid delivers electricity from points of generation to consumers, and the electricity delivery network functions via two primary systems: the transmission system and the distribution system.

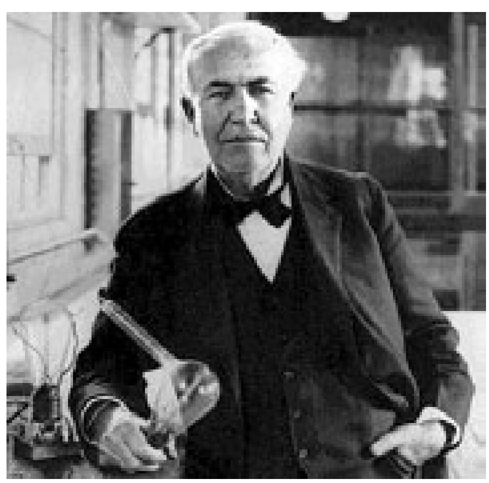
GUEST EDITORIAL

Beware The Smart Grid Cliff / By Jon T. Brock, President, Desert Sky Group, LLC

The transmission system delivers electricity from power plants to distribution substations, while the distribution system delivers electricity from distribution substations to consumers. The grid also encompasses myriad local area networks that use distributed energy resources to serve local loads and/or to meet specific application requirements for remote power, village or district power, premium power, and critical loads protection. But when we start talking more specifically about the Smart Grid, many more definitions exist. Moreover, to call it "smart" assumes that the existing grid is "dumb."

An analogy that I have adopted from the DOE is the comparison of the forefathers of telecommunications and electricity markets. The story goes like this:

Alexander Graham Bell



Thomas Alva Edison

If Alexander Graham Bell were somehow transported to the 21st century, he would not begin to recognize the components of modern telephony – cell phones, texting, cell towers, PDAs, etc. But by contrast, Thomas Edison – one of the grid's original architects – would be totally familiar with the grid. In that respect, the legacy grid we have today is "dumb."

Going back to my Y2K example, the reason that we had little to no blackouts when the date switched from '99 to '00 is not only due to all the hard work put in to prepare, but also to the fact that many of the distribution and transmission networks in 1999 did not care about a date – again, "dumb."

Obviously, the Smart Grid has many definitions, often depending on who's doing the defining and/or the composition of the intended audience. I will not attempt to define it yet again here, but instead, let's examine its components.

Despite all the "hype" around smart metering and the fact that someday I can watch my car charge from a smart phone; electric grid stakeholders representing utilities, technology providers, researchers, policymakers, and consumers have worked together to define the functions of a Smart Grid. Through regional meetings convened under the Modern Grid Strategy project of the National Energy Technology Laboratory (NETL), these stakeholders have identified the following characteristics or performance features of a Smart Grid:

- Self-healing from power disturbance events
- Enabling active participation by consumers in demand response
- Operating resiliently against physical and cyber attack
- Providing power quality for 21st century needs
- Accommodating all generation and storage options
- Enabling new products, services, and markets
- Optimizing assets and operating efficiently

Not to disparage the efforts of the utilities winning stimulus funds – which, as most of us in the industry know, have been split into categories such as investment, demonstration, and innovative research – but I fear that the business cases of the awarded stimulus put too much emphasis on benefits that are heavily dependent on smart metering and time-differentiated rates. Granted, that was the intent of the DOE. However, getting an infrastructure in place, stabilized, and working well with proven standards and interoperability targets is crucial before moving to end-use consumers. As I stated at the beginning of this article, I fear a "cliff" or market correction is coming, given the way Smart Grid is characterized at the moment.

GUEST EDITORIAL

Beware The Smart Grid Cliff / By Jon T. Brock, President, Desert Sky Group, LLC

As defined by NETL, there are several functions that the Smart Grid can address and not all of them are focused on real-time rates for residential consumers. For instance, recently I have been researching various T&D technologies such as Volt/VAR control & optimization, load balancing, and self-healing solutions that do not necessarily require a touch-point at every consumer and can deliver benefits in a rapid fashion as it relates to digitizing the electric grid. However, these technologies are not as prevalent in the current investment or demonstration awards as smart metering. The innovation research funds will go towards electro-fuels, advanced carbon capture technologies, and transportation battery storage.

I am not saying that smart metering and time-differentiated rates for end-use consumers are not important or that they do not have benefits. To the contrary, they are vital priorities that will eventually change the way we live (remember rotary phones?). What I am saying is that regulators, utilities, ratepayers, and investors alike will have to be patient when expecting the benefits of the Smart Grid to be realized. This is much easier said than done. Are we about to enter the trough after the hype? You bet… but this time, we know it. ■

About the Author

Jon Brock is President of utility and energy advisory firm, Desert Sky Group, LLC. He formed Desert Sky Group to address the needs of the utility and energy industries, specifically the need for independence and unbiased advice in changing markets. A former co-founder and COO of UtiliPoint International, Inc., Mr. Brock has over 20 years of experience delivering advice on utility and energy markets in areas ranging from utility business design, business plan development and review, business process optimization, and business infrastructure design and deployment of AMI, distribution technology, Smart Grid, customer service, outsourcing and benchmarking. He has served on utility/energy-related boards in the member and advisory member positions and has provided testimony and audit services to state and provincial commissions related to utility technology investments. Mr. Brock holds a bachelor of science in management science/computer systems from Oklahoma State University and an MBA from the University of Tulsa. He can be reached at *jbrock@desertskygroup.com*.

Applications of Advanced Distribution Automation in the Smart Grid Environment

By Nokhum Markushevich,
VP and Principal Consultant,
Utility Consulting International
(San Jose, California)

Advanced Applications in Distribution Automation are among the key components of the Smart Grid. Such applications enable the dynamic optimization of the operations of the Smart Distribution Grid to improve the reliability, power quality, and efficiency of the electric grid in an intensified cyber security environment. The Advanced Distribution Automation (ADA) requirements and conceptual designs described in the use cases in the Electric Power Research Institute (EPRI) IntelliGrid project could be a basis for further development to become the core components of the Smart Distribution Grid.

When there is significant penetration of Smart Grid technologies – Advanced Metering Infrastructure (AMI), Demand Response (DR), Distributed Energy Resources (DER), including Electric Storages and Plug-in-Electric Vehicles (PEVs), Power Electronics (PE), and advanced communications, the existing ADA applications will need significant upgrades, and some new applications will need to be developed. With the diversity of the new technologies and their utilization in a Smart Grid, the modeling of the components of distribution grid operations and their impacts on other power system domains must be reviewed.

The following ten ADA applications are described in the IntelliGrid project:

1. Real-time Distribution Operation Model and Analysis (DOMA)
2. Fault Location, Isolation and Service Restoration (FLIR)
3. Voltage/var Control (VVC)
4. Distribution Contingency Analysis (DCA)
5. Multi-level Feeder Reconfiguration (MFR)
6. Relay Protection Re-coordination (RPRC)
7. Pre-arming of Remedial Action Schemes (PRAS)
8. Coordination of Emergency Actions (CEmA)
9. Coordination of Restorative Actions (CRA)
10. Intelligent Alarm Processing (IAP)

In this article we will briefly review the existing design of three major applications (the first three in the above list), and discuss the expected upgrades of these applications needed to meet the Smart Grid requirements. These applications, in the current state, had been implemented in a number of utility pilot projects and in ongoing operations (e.g., BC Hydro, FPL, JEA, Progress Energy Florida, OPPD).

Near-real-time Distribution Operation Model and Analysis (DOMA)

This application provides the situational awareness of distribution system operations. Currently, it is based on input data collected from various corporate databases, SCADA, and operator's entries. In the Smart Grid environment, the multifunctional AMI system, customer EMS, market and weather IT systems will become significant sources of information support for the ADA applications. DOMA will process these various input data into a near-real-time and short-term look-ahead comprehensive models of distribution operations, to be used as a base for other ADA applications and to provide the operators with analyses of the behavior of the distribution system. A high level illustration of the information flow for DOMA application is presented in **Figure 1**.

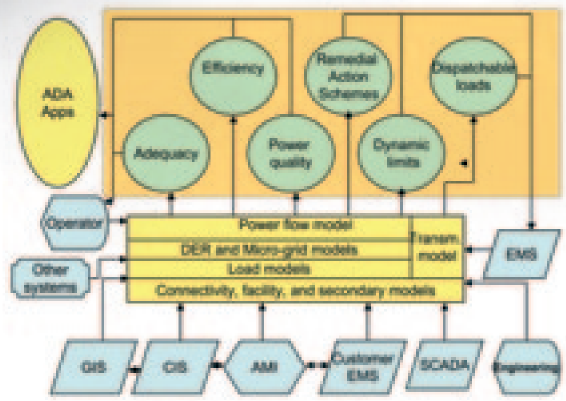
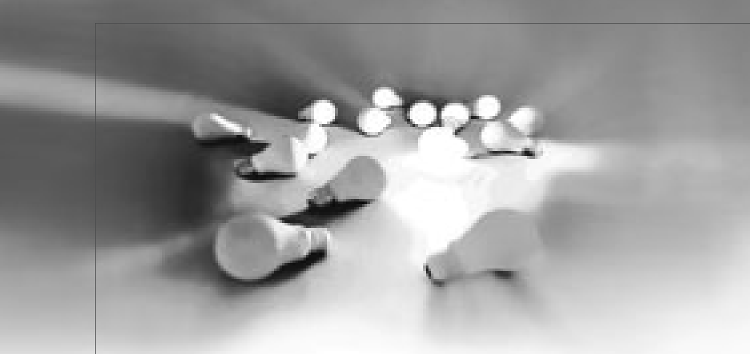


Figure 1: Data Sources, Models, & Analyses in DOMA

The DOMA functionality is based on the following component models:

- **Model of transmission/sub-transmission system.** This model needs to account for the impact of the distribution operations on transmission operations.
- **Model of distribution circuit connectivity.** This model is supported by the GIS database for nominal connectivity and by SCADA and operator's input for real-time updates. Improvement in the timely updates and comprehensiveness of GIS databases is needed.
- **Models of distribution nodal loads.** At the present time, the nodal load modeling in distribution is based on 'typical' real load shapes and expert estimates of the power factors for a number of load categories and on the monthly billing data. In the Smart Grid environment, the concept of 'typical' load shape is not applicable due to the diversity of possible behavior of the many small, distributed generators, electric storage devices, plug-in electric vehicles, and demand response means scattered among many customers. The real and reactive load models – individual or aggregated – shall reflect the behavior of these composite loads depending on the known weather, prices, voltage, time of day, and other factors. The AMI data, if properly processed, will provide a much better distribution nodal load models.
- **Models of Distributed Energy Resources and Micro-grids.** As the minimum, the DER models should be sufficient to estimate the generated kW and kvars at any given time, the financial attributes, and the capability curves. These models can be supported by SCADA, Customer Information Systems, DER and AMI data management systems, by aggregators, and by weather forecast systems.



The models of the Micro-grids can be viewed by the utility as aggregated object at the point of common coupling, or they can consist of the individual element models within the micro-grid. The utility should know the aggregated impact of micro-grid separation on both the utility and on the micro-grid.

- **Models of distribution circuit facilities.** These models, in addition to the conventional facility models, include the models of the secondary circuit equivalents. Presently, these models are developed based on expert estimates and may significantly differ from the real objects, resulting in large errors of voltage modeling and, consequently, in reducing the operational tolerances. Based on the voltages and powers measured by Smart Meters, adequate secondary equivalents can be derived.
- **Model of distribution power flow/state estimation.** Under conditions of the Smart Grid, the power flow/state estimation will need to additionally model the price-dependent events, and solve radial and meshed networks with multiple generation busses in different modes of operation.

The modeling discussed above will increase the accuracy of the power flow model, thus supporting a better utilization of the distribution systems.

The analysis part of the DOMA application includes the following analyses:

- **Analysis of adequacy of distribution system operations.** The adequacy of the operations is defined by the loading of the distribution elements, by the transfer capacity of normally open ties, and by the consistency of the fault currents with the capabilities of distribution facilities and protection settings. Under the Smart Grid conditions, the transfer capacity analysis shall take into account the availability, impacts, and cost of involvement of DER, Micro-grids, DR, PEV, ES, and Feeder Reconfiguration and Volt/var/Watt control applications. The fault analysis will also estimate the impact of the fault on the status and operations of the DER.
- **Power quality analysis.** Presently, the power quality analysis of the DOMA application analyzes the voltage deviations and voltage imbalance calculated by the power flow model. In the Smart Grid environment, this sub-function will analyze the voltage deviations, sags and swells measured and collected by the AMI system, will analyze the correlations between higher harmonic levels and operations of shunt devices and power electronics, including converter-based DER devices.
- **Analysis of the economic efficiency.** The economic efficiency can be determined in different ways depending on the utility business environment and objectives. The following components of the economic efficiency of distribution operations can be suggested: 1) Evaluation of the incremental cost of delivered energy by components, one of which is the cost of energy losses, and 2) Evaluation of the incremental benefits due to a particular change in distribution operations implemented in the utility. The incremental cost may include the cost of supply from both bulk energy sources and distributed energy sources, the incremental cost of demand response incentives, the cost of losses, the penalties for limit violations, etc. The evaluation of the incremental benefits of "what-if" operations can be done by DOMA in the near-real time mode with pre-defined changes calculating the difference between the actual operations and the "what-if" operations.
- **Determining the dynamic T&D bus voltage limits.** Presently, in many cases, the T/D bus voltage limits are constant for an extended time interval. The dynamic optimization of the distribution system operations results in different optimum voltages at the distribution side of the T&D substation. These voltages can be supported within a certain range of the transmission-side voltages. This range defines the transmission-side voltage limits at the time of optimization. There may be another set of dynamic voltage limits: the power quality limits, when the voltage at the buses shall satisfy the standard voltage tolerances at the customer terminals. The dynamic voltage limits defined by DOMA should be submitted to the transmission domain for use in the Wide Area Situational Awareness applications.
- **Determining the available dispatchable real and reactive load at the T&D buses.** The significant penetration of DER, Demand Response, and PEVs in combination with Volt/var/Watt control and Feeder Reconfiguration applications will provide wide ranges of dispatchable loads at the T&D buses. These loads will be dependent on a number of conditions, such as real-time energy prices, reliability signals (can be price also), ancillary service conditions, temporary voltage limit for peak load reduction, weather, etc. Hence, the dispatchable loads at the distribution side shall be also based on behavioral models.

- **Determining the aggregated at the T&D buses parameters of remedial action schemes.** In many cases the actuators for load-shedding Remedial Action Schemes (RAS) are located in the distribution system on per feeder basis. In the future, the load shedding could be done in a more refined manner moving it closer to the end users, e.g., using micro-grids, operating in absorbing mode. The Wide Area Measurement and Control System (WAMCS) should define for each moment the amount of load to be armed at different RAS to satisfy the power security requirements. The ADA application should support the model of available loads under different RAS, their interrelationships, and their behavior under different circumstances.

Fault Location, Isolation and Service Restoration (FLIR)

In the current design of the ADA application, the fault location is based on SCADA-supported fault indications, trouble-call systems, and, sometimes, on fault-locating devices. In the Smart Grid environment, the Smart Meters, customer EMS, and fault predictors will become significant sources of information for fault location. The processing of these, sometimes, voluminous data will need to be accomplished in a very short time interval.

The switching orders generated by the application for fault isolation and service restoration, will include, in addition to switching devices and feeder paralleling, separations of micro-grids, synchronization of disconnected DER, and enabling of DR. The solutions should be dynamically optimized based on the expected operating conditions during the time of repair. The FLIR application should be coordinated with other ADA applications, such as MFR, VVWO, RPRC, and CRA.

Voltage, Var, and Watt Optimization (VVWO)

This is a major multi-objective ADA application performing dynamic optimization of the distribution operations taking into account all significant impacts of the application on the operations in different domains (**Figure 2**).

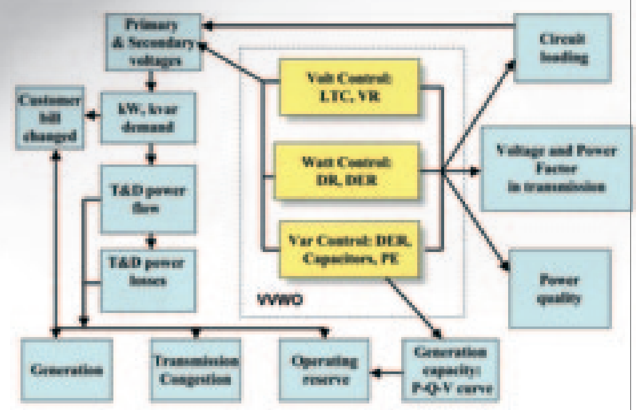


Figure 2: Impact of VVWO on Operations in Different Power System Domains

In the Smart Grid environment, in addition to the current control of voltage controller settings and feeder capacitor statuses, the application should be able to control the reactive power of DER and other dynamic sources of reactive power. Under some objectives, the application should be able to control the Demand response means and the real power of DER. Therefore, the Volt/var optimization becomes a Volt/var/Watt optimization.

As follows from the above discussion, the ADA applications should actively exchange information with applications and IT systems in other power system domains. A high-level information exchange diagram between the Distribution Grid Management and other systems is presented in the EPRI Report to NIST on the Roadmap for Smart Grid Interoperability Standards.

A more detailed illustration of the information exchange just between the DMS and EMS is presented in **Figure 3**.

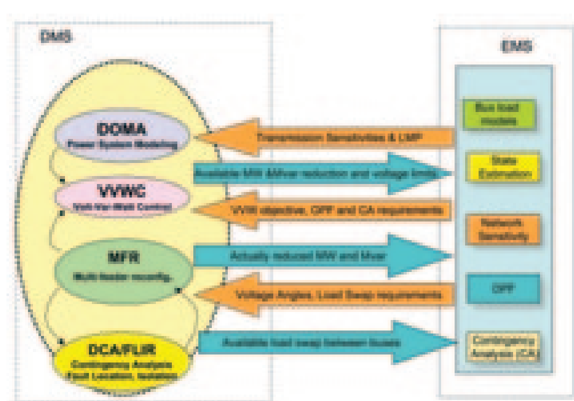


Figure 3: Information Exchange between DMS & EMS for Dynamic Optimization of Power System Operations

Conclusions

- The existing designs of ADA applications can be used as foundation of the ADA applications in the Smart Grid environment.
- Comprehensive near-real-time and short-term look-ahead models of the behavior of the Smart Grid components are the basis of ADA applications in the Smart Grid environment.
- The upgrade requirements for such models may define the specification and prioritization of AMI, DER and DR.
- Integration of Smart Grid technologies into ADA applications also implies the ability to optimally control some of the new objects.
- Active exchange of information between the Distribution Operation domain and other power system operation domains will be needed for comprehensive dynamic optimization of power system operations.

About the Author

Dr. Nokhum Markushevich has more than 45 years of experience in power system operations, research, and education. He worked for the Latvian Power Company for 29 years and has been with Utility Consulting International (UCI) since 1992, where he consults in the areas of EMS and DMS. He was the Distribution Operations Domain Leader in the EPRI IntelliGrid project and had actively participated in the development of the EPRI Report to NIST on the *Roadmap for Smart Grid Interoperability Standards*. Dr. Markushevich has authored several books and more than 100 papers on power system operations, EMS and DA.

Volt/VAR Optimization Reduces Losses, Peak Demands

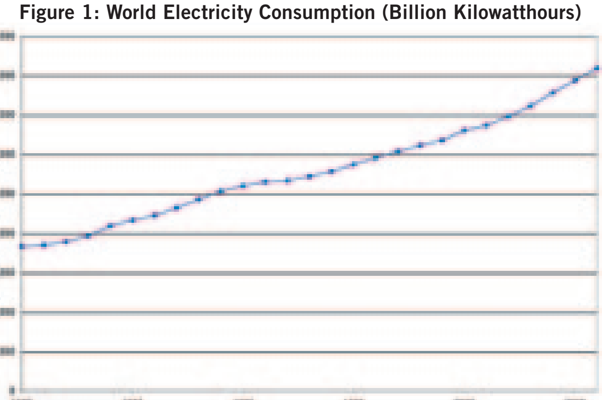
By Xiaoming Feng, ABB Corporate Research and William Peterson, ABB Power Systems Raleigh, North Carolina USA

Ever wondered how much electric energy the world consumes or how much energy is lost on its way from power plants to end user customers? Have you wondered how much energy could be saved or greenhouse gas emissions could be cut by reducing energy losses by only a small amount? With the proper implementation of technology and a concerted effort we can reduce electric energy losses and the demands made on electric distribution systems. A wide panorama of technology already exists to achieve that objective. Voltage and VAR Optimization (VVO) is the latest addition to those applications. But unlike the traditional approach using uncoordinated local controls, VVO uses real-time information and online system modeling to provide optimized and coordinated control for unbalanced distribution networks with discrete controls.

Electric distribution companies can achieve huge savings in the new frontier of energy-efficiency improvement by maximizing energy delivery efficiency and optimizing peak demand. VVO will help achieve these objectives by optimizing reactive resources and voltage control capabilities continuously throughout the year.

The world has a huge appetite for electric energy, consuming thousands of billions of kilowatt-hours (kWh) annually, a figure that continues to climb as more countries become industrialized. The world's electric consumption has increased by about 3.1 percent annually between 1980 and 2006, according to International Energy Annual 2006 by the US Energy Information Administration and is expected to grow to 33,300 billion kWh by 2030, according to World Net Electric Power Generation: 1990–2030, also by EIA. (**Figure 1**) The world's electricity consumption for 2008 was 16,790 billion kWh so by 2030 the world demand for electricity is expected to have almost doubled.

Figure 1: World Electricity Consumption (Billion Kilowatthours)

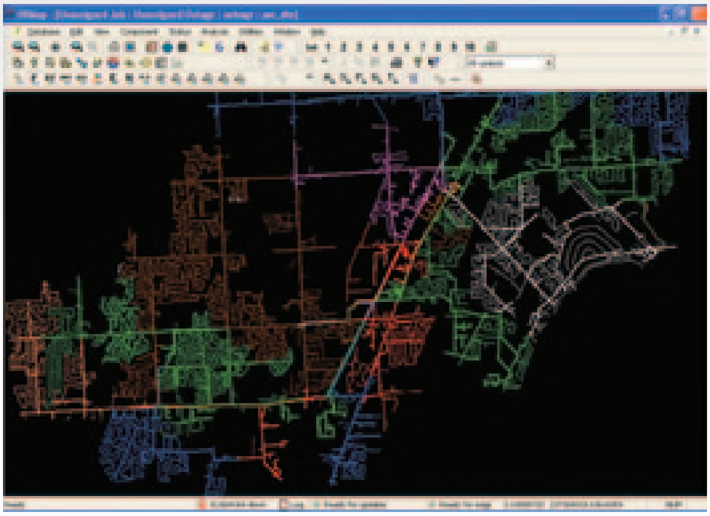


Electric Energy Losses

Currently a significant amount (about 10 percent) of electric energy produced by power plants is lost during transmission and distribution to consumers. About 40 percent of this total loss occurs on the distribution network. In 2006 alone, the total energy losses and distribution losses were about 1,638 billion and 655 billion kWh, respectively. A modest 10 percent reduction in distribution losses would, therefore, save about 65 billion kWh of electricity. According to the 2009 *CIA Online Factbook*, that's more electricity than Switzerland's 7.5 million people consumed in 2008 and equates to 39 million metric tons of CO_2 emissions from coal-fired power generation. As the demand for electricity grows, new power plants will have to be built to meet the highest peak demand with additional capacity to cover unforeseen events. The peak demand in a system usually lasts less than 5 percent of the time (i.e., just a few hundred hours a year). This means that some power plants are only needed during the peak load hours and their productive capacity is utilized only occasionally. By active demand management on the distribution system, through demand response and VVO, the peak demand on the whole electric grid can be reduced. This eliminates the need for expensive capital expenditure on the distribution, transmission, and the generation systems.

Even very modest reductions in peak demand would yield huge economic savings. For the United States in 2008, for example, the non-coincidental peak demand (i.e., the separate peak demands made on the electrical system recorded at different times of the day) was about 790 GW. Thus, with every one percent reduction in the peak demand there would be a reduced need to build a 7,900 MW power plant.

Figure 2: Distribution system overview from network manager system (DMS)



For any conductor in a distribution network, the current flowing through it can be decomposed into two components – active and reactive. Reactive power does not do real work but uses the current carrying capacity of the distribution lines and equipments, and contributes to the power loss. Reactive power compensation devices are designed to reduce or eliminate the unproductive component of the current, reducing current magnitude – and thus energy losses.

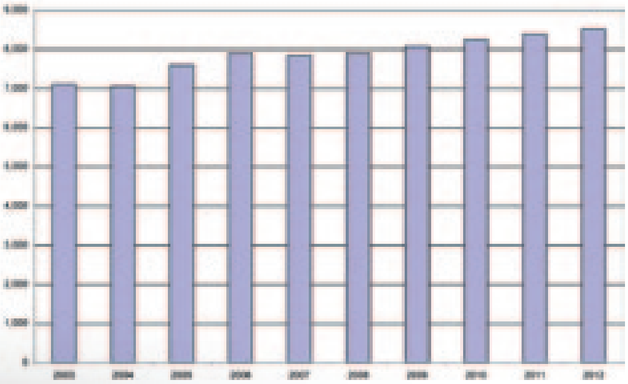
The voltage profile (spatial distribution and voltage magnitudes) on the feeders (medium-voltage lines to distribute electric power from a substation to consumers or to smaller substations) can also affect the current distribution, depending on the types and mixture of loads in the system, although indirectly and to a smaller extent, thus affecting power loss.

Distribution System Losses

The electric distribution network moves electricity from the substations and delivers it to consumers. The network includes medium-voltage (less than 50 kV) power lines, substation transformers, pole- or pad-mounted transformers, low-voltage distribution wiring and electric meters. The distribution system of an electric utility may have hundreds of substations and hundreds of thousands of components all managed by a distribution management system (DMS) as depicted in **Figure 2**, above.

Most of the energy loss occurring on the distribution system is the Ohmic loss resulting from the electric current flowing through conductors. The energy loss is due to the resistance in the conductor. The amount of loss is proportional to the product of the resistance and the square of the current magnitude. Therefore, losses can be reduced by reducing either the resistance the current magnitude, or both. The resistance of a conductor is determined by the resistivity of the material used to make it, by its cross-sectional area, and by its length, none of which can be changed easily in existing distribution networks. However, the current magnitude can be reduced by eliminating unnecessary current flows in the distribution network. (**Figure 3**)

Figure 3: 1% Peak demand reduction in MW (US)



Voltage and VAR Control Devices

Voltage regulating devices are usually installed at the substation and on the feeders. The substation transformers can have tap changers, which are devices that can adjust the feeder voltage at the substation, depending on the loading condition of the feeders.

Special transformers with tap changers called voltage regulators are also installed at various locations on the feeders, providing fine-tuning capability for voltage at specific points on the feeders.

Reactive compensation devices (i.e., capacitor banks) are used to reduce the reactive power flows throughout the distribution network. The capacitor banks may be located in the substation or on the feeders. Capacitor banks can be fixed or switched.

Traditional Control Versus VVO

Traditionally, the voltage and VAR control devices are regulated in accordance with locally available measurements of, for example, voltage or current. On a feeder with multiple voltage regulation and VAR compensation devices, each device is controlled independently, without regard for the resulting consequences of actions taken by other control devices. This practice often results in sensible control actions taken at the local level, which can have suboptimal effects at the broader level.

Ideally, information should be shared among all voltage and VAR control devices. Control strategies should be comprehensively evaluated so that the consequences of possible actions are consistent with optimized control objectives. This could be done centrally using a substation automation system or a distribution management system. This approach is commonly referred to as integrated VVO.

The accelerated adoption of substation automation (SA), feeder automation (FA) technology, and the widespread deployment of advanced metering infrastructure (AMI) over the last few years have laid the foundations for a centralized control approach, by providing the necessary sensor, actuator, and reliable two-way communications between the field and the distribution system control center.

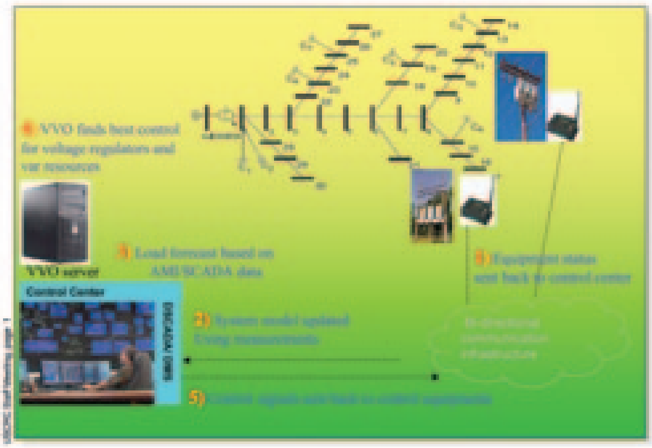
Until recently, however, a key technology has not been available that can take advantage of advanced sensing, communication, and remote actuation capabilities that can be used to continually optimize voltage and VAR. Prior generations of VVO technologies have been hindered by their inability to model large and complex utility systems, and by their unsatisfactory performance in solution quality, robustness and speed.

How Does VVO Work?

VVO is an advanced application that runs periodically or in response to operator demand, at the control center for distribution systems or in substation automation systems. Combined with two-way communication infrastructure and remote control capability for capacitor banks and voltage regulating transformers, VVO makes it possible to optimize the energy delivery efficiency on distribution systems using real-time information.

VVO attempts to minimize power loss or demand without causing voltage/current violations. Voltage/current violations refer to the undesirable excursion from normal operating range, e.g., current exceeding the maximum limit safe for a given conductor type, or voltage exceeding a limit unsafe for the consumer or falling short of a limit needed for normal operation for end users. VVO is designed to work in various system design and operating conditions. A distribution system could be meshed, supplied from multiple sources, unbalanced construction, and unbalanced loadings.

Figure 4: How VVO Works



The control variables available to VVO are the control settings for switchable capacitors and tap changers of voltage regulating transformers. For a single switchable capacitor bank, the control variable is binary, with value zero and one corresponding to the switched out or in status. For a typical tap changer, the control variable is an integer that varies from -16 to +16. The capacitor and regulator controls can be either ganged (multiple phases operated in unison) or un-ganged (each phase -operated independently).

Main Benefits of VVO

The main benefits of VVO for distribution system operators are:

- Improved energy efficiency leading to reduced greenhouse gas emissions.
- Reduced peak demand and reduced peak demand cost for utilities

General Problem Definition for VVO

VVO must achieve the objective of minimize power loss or MW demand while maintaining acceptable voltage profiles on the distribution feeders. VVO can be formulated to minimize the weighted sum of energy loss + MW load + voltage violation + current violation, subject to a variety of engineering constraints:

- Power flow equations (for multi-phase, multi-source, unbalanced, meshed system)

- Voltage constraints (phase to neutral or phase to phase)
- Current constraints (cables, overhead lines, transformers, neutral, grounding resistance)
- Tap change constraints (operation ranges)
- Shunt capacitor change constraints (operation ranges)

The control variables for optimization include:
- Switchable shunts
- Controllable taps of transformer/voltage regulators
- Distributed generation

Technical challenges

VVO in essence is a combinatorial optimization problem with the following characteristics:
- Integer decision variables – both the switching status of capacitor banks and the tap position of regulation transformers are integer variables.
- Nonlinear objective being an implicit function of decision variables – energy loss or peak demand are -implicit functions of the controls.
- High dimension nonlinear constraints – power flow equations numbering in the thousands in the multi-phase system model.
- Non-convex objective and solution set.
- High dimension search space – with un-ganged control, the number of control variables could double or triple.

People who are familiar with optimization problems will tell you that mixed-integer nonlinear, non-convex (MINLP-NC) problems are the worst kind to solve. The major challenge is to develop optimization algorithms that are efficient and robust for large problems. Since a certain amount of computation (i.e., CPU time) is needed to evaluate the loss and demand for a single specific control solution (a single functional evaluation), an algorithm that requires fewer functional evaluations to find the optimal solution is generally regarded as more efficient than one that requires more functional evaluations to achieve the same objective.

Next Generation VVO

A new-generation VVO capable of optimizing very large and complex networks with online application speed is emerging. An innovative solution methodology enables the detailed and accurate modeling of the distribution system components and connections. It rapidly identifies the optimal voltage and VAR operation strategy from millions, if not billions, of operation possibilities using advanced mixed-integer optimization algorithms.

A prototype has been developed, which has performed very well in the lab with distribution network models of a real utility system. Both the solution quality and speed robustness met or exceeded design criteria for online applications. This new generation VVO is capable of optimizing very large and complex networks with online application speed.

The following table is a summary comparison of between the new method and previous traditional ones.

Traditional Method	New Method
Single phase equivalent model	Multi-phase, unbalanced model
Balanced load	Unbalanced load
Single source	Multi-source
Radial system	Meshed system
Ganged control	Un-ganged control
Academic system size	Real utility system size
Offline performance	Online performance
Heuristic	Optimization theoretic

To accurately model a distribution network's behavior under different control strategies, VVO uses a detailed load flow model where individual phases of the system construction and loading are modeled explicitly. Loads or capacitor banks can be delta or wye connected.

Transformers can be connected in various delta/wye and secondary leading/lagging configurations with or without ground resistance, with primary or secondary regulation capability. Both voltage and VAR controls can be ganged or un-ganged. The method works on radial as well as meshed networks, with single or multiple power sources. Voltage constraints controls are enforced for each individual phase, using phase-to-ground or phase-to-phase voltage, depending on the connection type of the load.

One Smart Technology at a Time

With the accelerating deployment of advanced sensor network, smart metering infrastructure, and remote control capability, there is a growing need for smart applications like VVO that optimize the operation of the distribution system. The new generation of VVO technology is just of the many smart grid technologies that can help us to have efficient, reliable electric power while reducing energy and CO_2 footprint. ■

About the Authors

Xiaoming Feng is based at the ABB Corporate Research Center in Raleigh, North Carolina. He can be reached at *xiaoming.feng@us.abb.com.*

William Peterson is based at ABB Power Systems in Raleigh, North Carolina. He can be reached at *william.peterson@us.abb.com.*

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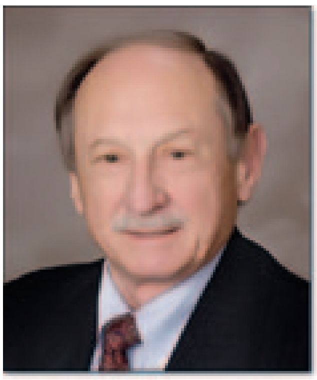


Steve Dalyai
President/CEO

Norm Lavoie
VP & General Manager

QEI, Inc.

Springfield, New Jersey USA

> "...I believe that the government led – and partially federally funded – Smart Grid initiative is just what our industry needs to move forward with innovative projects to bring the grid up to 21st century standards..." – **Steve Dalyai**

Founded in 1960 as Quindar Electronics Incorporated, QEI is credited with the introduction of the first transistorized voice frequency, audio tone telemetry products for electric power network monitoring and control. By the early 1970s the company introduced a full function, computer based SCADA system that was widely deployed in electric utility applications and included a line of intelligent remote terminal units (RTUs). In 1975 the company's name was shortened to QEI under new ownership. Today, QEI continues to serve those same markets with solutions that are firmly grounded in a half-century of innovation and progress. –Ed.

EET&D: Steve, this year marks quite a milestone for QEI, doesn't it? To remain an independent SCADA and substation automation supplier for 50 years is quite an accomplishment – one that may be yours alone to claim at this point. Just a little over two years ago we saw Advanced Control Systems (Atlanta, Ga.) acquired by EFACEC, a Portuguese company. They were, I believe, the only other independent SCADA supplier in North America with that kind of longevity, right?

Dalyai: Yes, that's true. But to be accurate, ACS was founded in 1975 – fifteen years after Quindar, and of course, I'm very proud of what we've accomplished during that time.

EET&D: One of the things I've noticed recently is that several of the areas that were being explored in the early days of SCADA are now key dimensions of the Smart Grid Era. A few of those that immediately come to mind are Demand Response, Volt/VAR Control and Feeder Automation. What can you tell our readers about the genesis of those applications?

Dalyai: Distribution Automation began its evolution in the early 1980s. Primary applications included Peak Demand Reduction – now called Demand Response – and coordinated Volt/VAR control. The communications challenge for distribution feeder applications was initially addressed with distribution line carrier systems that provided two-way communications between the substation RTU and the feeder devices. Peak demand reduction and automatic VAR control were two key applications we layered onto our SCADA platform.

EET&D: Was all of this internally developed?

Dalyai: : Although we've developed the vast majority of our product line internally and continue to invest heavily in R&D, we made some strategic acquisitions to complement our offerings. In 1988 we acquired what was then General Electric's Total Load Management System. That acquisition included a high-performance distribution line carrier system as well as a line of compatible load control receivers. To complete the solution set, we developed a variety of other feeder devices and became the first supplier of a fully integrated SCADA and distribution line carrier based system. In 2001 we acquired the automatic capacitor controller line of Cooper Power Systems and integrated it into our SCADA system to form a complete Reactive Power Management application.

EET&D: While longevity in the SCADA business certainly demonstrates survivability in what has proven to be an extremely volatile market, it can also be a double-edged sword with past sins sometimes coming back to haunt you. Has that been a problem for you?

Lavoie: Yes, I can vouch for that because a big part of my job is making sure that our customers always come first. That posture doesn't always make my job easy, but as testimony to the fact that our position is more than lip service, we continue to support the telemetry products that we introduced in 1960 and offer functional equivalents using modern design for replacement and/or expansion purposes. We also have several decades-old SCADA systems in the field that have been brought up to current state-of-the-art functionality and specifications. Moreover, we have a separate dedicated customer service department that is ISO9001 certified, as is our entire organization.

EET&D: For most companies that have been around for any substantial length of time, keeping up with the latest standards, trends and technologies rapidly becomes an implicit – and expensive – dimension of survival. What advice would you offer to companies just starting out with today's technology, but that will become the legacy installations of tomorrow?

Dalyai: First of all, I think it's vitally important to stay connected to the industry through regular and active participation in industry professional associations, trade groups and standards-making organizations. Doing so is never easy or cost-free, but I personally feel that our participation has been a critical ingredient in our long-term success and sustainability.

Secondly, it is important to understand that electric utilities operate a critical infrastructure, the performance and reliability of which have major implications for the economy, national security, and public safety. This means that new products integrated into the utility network must be based on technology that will remain viable and serviceable much longer than those ones used in general industrial applications. Our product development programs are based on this philosophy, and I am quite sure, have contributed to the company's longevity.

EET&D: Can either of you offer some specific instances of why such participation is important?

Lavoie: Sure, I can give you several. For example, MultiSpeak® is an industry-wide software standard that facilitates interoperability of diverse business and automation applications, used mainly by rural electric cooperatives.

It was developed and is maintained by the MultiSpeak Initiative and provides a standard protocol for interoperable applications among various utility systems such as SCADA, Geographic

[1] MultiSpeak® is a registered trademark of the National Rural Electric Cooperatives Association.

Information Systems, Outage Management Systems, and so forth. QEI was the first SCADA system supplier to adopt this standard and pass the compliance test.

Another example is QEI's participation in the development of the Electric Power Research Institute sponsored Utility Communications Architecture (UCA) initiative to provide a suite of communications protocols for seamless interoperability between the various utility systems. One of its components was the Inter-Control Center Protocol (ICCP) for applications between control system master stations such as SCADA and Energy Management Systems. ICCP was eventually adopted as the international standard, IEC-61870-6. The other component was UCA2.0, which was intended for communications between intelligent devices in the substation and between the substation and the SCADA master station. UCA2.0 was the foundation for another international standard, the IEC61850. QEI was an early adopter of both these protocols.

Dalyai: Without making the investments in time and resources that were necessary to participate in the evolution of those standards, I can't even imagine that we would still be around. As I've said, being part of those activities is both time-consuming and expensive, but to not be involved puts you on the outside looking in – not where you want to be in these fast-paced times.

EET&D: I know that you originally came from the legendary Bell Telephone Laboratories and as a result, your roots are squarely in engineering. As an engineer with over four decades of experience, what are some of your thoughts about the Smart Grid initiative and grid transformation?

Dalyai: The Smart Grid initiative is of great interest and a long awaited opportunity for QEI and other suppliers to the utility automation market. As currently envisioned Smart Grid has a strong focus on managing energy usage at the end user level. However, it must also include management of the electric power network itself. The reliability and the security of the network are essential for providing quality service to those same end users, and without both parts, the results will probably fall short of expectations.

EET&D: There's a rising controversy over whether the Smart Grid label itself sends a wrong message – especially to the general public – about the present state of the grid. To an average person, I can see how talking about Smart Grid transformation can sound like we're emerging from the Dark Ages. Are we?

Dalyai: The concept of an intelligent grid is not new since the key components of it date back at least three decades. During that time, minicomputer-based control centers and microprocessor-based RTUs were introduced, creating the first intelligent and flexible automation platforms. That might have qualified as emerging from a fairly simplistic era, but what we are embarking on today – while certainly exciting, innovative and long overdue – is not really a huge leap technologically, at least not in the areas that seem to be getting the most attention, such as that being attributed to smart meters.

For example, a fully functioning remote meter reading proof-of-concept pilot project was implemented in 1970 while I was still at Bell Labs – and that was forty years ago! The system utilized the switched telephone network facilities and a central office based Electronic Switching System in Holmdel, New Jersey to read utility meters in Hawthorn, Illinois. Since then, the technology has been updated, of course, but the fundamental difference today is the deployment scale and especially the level of investment. This is very much an economic issue, far more than a technological one.

EET&D: There appears to be a seemingly endless set of objectives for the Smart Grid, some of which are obvious and intuitive and others of which are quite aggressive. Still others seem to miss the mark entirely and are simply taking advantage of the opportunity to ride the Smart Grid wave. What do you see as the key areas that should top the list of Smart Grid objectives?

Dalyai: As currently envisioned, Smart Grid encompasses a wide range of functions and applications with a particular focus on smart metering at the customer premise. However, I believe – as do many of my colleagues – that priority should be given to the upgrade and automation of the system that delivers electric power to the final user, which is of course, is the distribution network itself.

EET&D: Another popular notion is that Smart Grid is mostly about transmission. Is there any validity to that?

Dalyai: Early applications of SCADA systems were focused on transmission systems because of the impact of transmission system faults on the reliability of the grid. Subsequently, besides basic telemetry and control functions, other applications such as Automatic Generation Control and later, Energy Management Systems with advanced applications, were introduced for transmission networks as well as early applications of IEDs in the substations. Here again, these and other advanced tools have been around for decades. So, while I don't know that there is a disproportionate emphasis on transmission, there is certainly plenty that can be done to improve the bulk power transmission network in terms of technology employed as well as from a regulatory and economic perspective.

EET&D: Is there anything else on the distribution side beyond metering that you feel warrants special attention or emphasis?

Dalyai: Again, the use of voltage reduction and load shedding to manage peak demand were the forerunners of today's Demand Response systems. I expect that as we go forward, other demand-side management applications will also be more widely deployed. These include optimal Volt/VAR control and fault location, isolation and service restoration – applications that directly improve the efficiency and the reliability of the distribution network.

EET&D: These developmental trends have helped usher in a rising level of attention on power delivery, but are there other factors that will cause this trend to continue?

Dalyai: The advent of intelligent field devices and computer based master stations provided the enabling technologies for automating the distribution network. Several pilot projects have been implemented, and there are some broad deployments but, in general, Distribution Automation still hasn't proliferated as extensively or as quickly as many of us had expected. There were, and perhaps still are, issues that prevent widespread deployments. Power quality and reliability are the two main issues that are routinely associated with distribution network performance, so I hope that continued focus on those issues by utilities and regulators will provide the driving forces needed to sustain that trend.

EET&D: Conversely, what do you feel are the impediments to the expansion of Distribution Automation?

Dalyai: The lack of availability of appropriate protocol standards – required for interoperability – was initially an impediment to the widespread deployment of DA systems. To be effective, DA must be an integrated system that aggregates information from the intelligent subsystems and processes it for various automation applications. To their credit, technical experts from utilities and vendors have recently joined together to address this issue, but other barriers still exist.

In my view the major impediment to the widespread deployment of DA has been the reluctance of utilities to make the necessary financial investments in the absence of a clear return on investment. Without the ability to forecast the bottom line benefit resulting from the complex infrastructure investment required, widespread adoption of DA will be protracted.

Lavoie: As Steve points out, a full range of interoperable protocols and interfaces were developed over the past several decades that have now been field-tested in numerous pilot implementations. With these developments, all technical barriers have been removed, clearing the way for full commercial deployment of integrated Distribution Automation systems. Even so, the deployment of DA systems still lags significantly behind expectations and needs.

EET&D: What do you see the Stimulus Bill doing for the electric utility industry overall?

Dalyai: Over the past decade – and particularly since deregulation – utilities have become very cost conscious with a strong focus on profits and short-term gains. Of course, this pervasive trend has permeated the entire business community as well as many budget-strapped governmental organizations; not just utilities. The result is deteriorating infrastructure, ranging from roads and bridges, to the electric power delivery network.

However, the health and well being of the electric power network is an absolute imperative for an industrialized society, and no industrialized nation can effectively survive in the 21st century without it. In today's brutally competitive and globalized free market economy, safe, reliable delivery of electric power is not a luxury, but an imperative. Therefore, I think this is one area where there's a strong argument for the government to encourage and even underwrite corrective action if the private sector is not able to adequately address this critical issue in a timely manner.

EET&D: So can I assume that you feel ARRA funding is going to positively affect the Smart Grid effort?

Dalyai: Yes, I believe that the government led – and partially federally funded – Smart Grid initiative is just what our industry needs to move forward with innovative projects to bring the grid up to 21st century standards. To accomplish this, fully developed, field-tested, ready for deployment DA technology can be further augmented with emerging technologies in IT, communications and software applications that have been developed, tested and standardized. However, while the government action may provide an initial impetus, in the longer term, utilities need to be incentivized to continue investing into the modernization of their assets. I believe the vendor community is waiting for this with full readiness and great anticipation.

EET&D: Lately there has been quite a bit of controversy about whether Smart Grid funds targeted to Advanced Metering Infrastructure projects are appropriately placed. In your opinion, should Smart Grid initiatives be driven primarily by utility-centric or customer-centric objectives?

Dalyai: To me, that's almost like asking whether we should build good highways or smart cars. The obvious answer is that we want and need both. However, if funding is available for only one or the other, I would think we would follow the path that's been taken all across the industrialized world, which is to develop a modern highway network first. In other words, if we don't address and correct the root causes first we'll just wind up driving smart cars on inferior roads, so it will be vitally important to address these objectives in the proper order.

EET&D: I suppose one could argue that all initiatives should be customer-centric, at least in the sense that the business case should be based on customer benefits. But when it comes to the targeting of Stimulus funds, should the primary objective be to improve the distribution network or make the customer premises smarter?

Dalyai: I think the situation very much parallels the transportation example. The fact is, utilities are in business to serve customers, but if the service is not reliable and affordable, inevitably customers will suffer. Clearly, it will be those same customers that will pay for smart homes, but if outages and inadequate service prevail, smarter homes will not provide the return on investment that those ratepayers are entitled to expect and receive – and in that case, nobody wins.

On balance, I feel that regardless of how the funds are applied, automation will play a central role in the ultimate outcome. Just how fast it will all happen is really the big question mark in my mind – but I'm very sure of one thing: we can't get started soon enough!

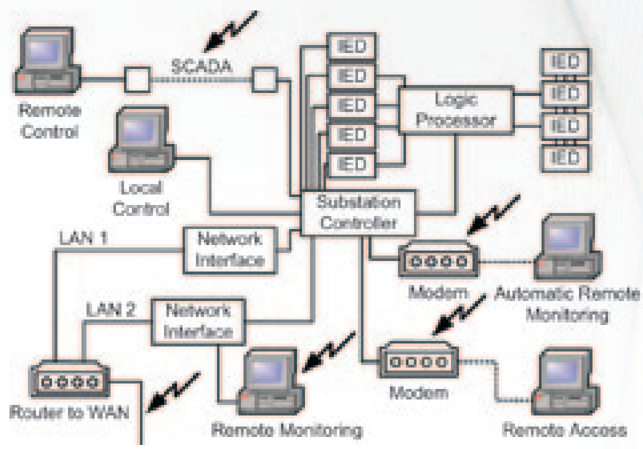
Sensible Solutions for Substation Network Security

By Dwight Anderson, Schweitzer Engineering Laboratories, Inc.

Modern power utility systems deliver information to a wide range of users in near real time and automate several tasks that streamline operations and performance. These new performance advantages often come with a challenge: cybersecurity. Integration and automation professionals can enhance the security of modern power utilities with the sensible, yet reliable methods described below.

Many networking technologies are built on a premise of trust and provide multiple benefits for operational efficiency. For example, a modern networked substation often allows the remote resolution of problems, preventing a utility from wasting many hours trying to locate a fault. Encroaching on this benefit are new cybersecurity regulations that do not easily align with control system remote diagnostics. Many of the new regulations emerge as a result of work in other sectors, such as information technology (IT). Sometimes, it is appropriate to apply the security principles learned from IT, and at other times, utilities are best served by approaching principles and regulatory norms from other industries with a circumspect posture. The application of IT security measures and regulations should not negatively impact the reliability or resiliency of grid operations.

News reports on cybersecurity tend to emphasize uncertainty and doubt. These reports, while well intentioned, can lead to an overreaction of increased legislation, while the more effective response would be to create and implement internal security policies, plans, training, and procedures. The incorporation of a variety of firewalls, virtual local-area networks (VLANs), virtual private networks (VPNs), and Internet Protocol Security (IPsec), as described below, is a powerful strategy for increasing network resiliency and preventing cyberintrusion. Once in place, these security and networking technologies provide a robust 'security in-depth' approach to securing critical infrastructure control systems, such as those found in modern smart grid substations.



Applying Firewalls as a Security Measure

One important security tool is the firewall. The name and its function originate from the firewall that can be found in automobiles or applied in the construction of buildings. An automobile's firewall confines fire to the engine compartment, preventing fire from progressing to the driver and passenger areas. The firewall must have holes in it for certain functions, such as steering, throttle control, and braking. Likewise, a network firewall restricts illegitimate traffic from flowing on the network segment, but allows legitimate data to proceed. The firewall makes these decisions based on a set of rules. Another firewall feature is the ability to log or document actions, including auditing actions. The rules for a firewall originate from a well-defined security policy. Typically, a firewall operates between network boundaries, where network communications meet. For example, a firewall would be found where data from the Internet (outsiders) meet the data from a corporate intranet (insiders).

Firewalls are often built into network equipment, such as computers, gateways, or routers, and provide a means to restrict network traffic, such as preventing outsiders from connecting to insiders. Just as there are holes in an automotive firewall, the rules for a substation may allow network holes, or ports, to allow certain TCP/IP network traffic to pass. For example, a firewall may have holes to pass email traffic assigned to Port 25 (Simple Mail Transfer Protocol, SMTP) or Port 110 (Post Office Protocol 3, POP3). These ports in the firewall allow legitimate network traffic to pass, but drop illegitimate traffic. Firewall rules that drop data packets often create an alarm or log file that notifies the user and/or administrator of a problem. As with any security tool, a firewall requires an understanding of the network design; unintentionally or inaccurately changing a firewall rule can impede important network traffic.

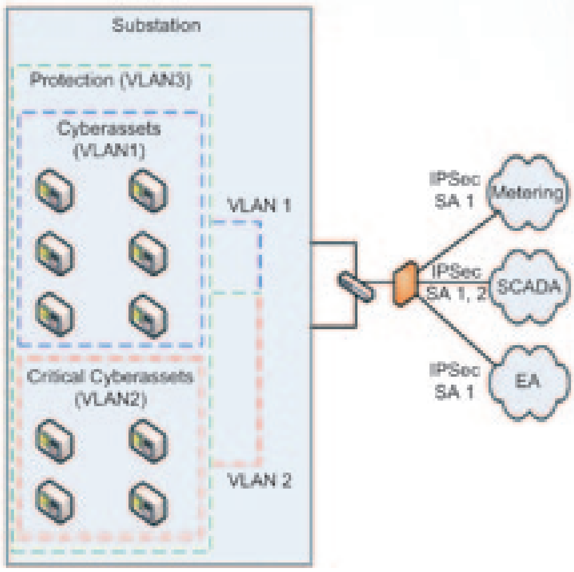
There are several firewall types: packet filtering, stateful inspection, and application proxy. Packet filtering examines the IP address and/or port and accepts or denies the packet through the firewall. The more popular type of firewall is called stateful inspection (often referred to as a session-based firewall), which bases the rules on the state of a connection or session. It adds slightly more depth to its protection. There are UNIX-based firewalls that run off IP tables or IP filters. These work well for a substation environment because they allow for some degree of fine-tuning (e.g., allowing control system packets and rejecting all other traffic). UNIX-based firewalls require more time and greater expertise to set up. As the name implies, an application proxy sets up an intermediary hardware path for the data packets. The proxy hardware receives all traffic to and from the destination and filters traffic based on its rule set. One advantage of a proxy firewall is that it hides the true IP addresses from outsider connections.

Firewalls provide logs and document attempts to connect to the network—very important features that will help modern substations meet regulatory requirements. These log files are an important source of useful information that can be used to prevent illegitimate access to a substation environment. Unfortunately, most security officers do not spend the time to review these log files.

The Proper Place for VLAN in a Resilient Network Design

Another important security tool is the virtual local-area network (VLAN). VLAN groups end devices and users into a particular network group or segment, allowing communication to occur only within that group. This provides better management of data traffic and segments network traffic with similar network security requirements, yielding better resiliency during high-traffic communications, even during a cyberattack. Unfortunately, a common misconception is that VLANs provide security for data packets.

VLANs provide a convenient means of moving users and/or devices to different broadcast domains. They require only a reconfiguration of the port that is used to connect to the network. For example, you could be working in Engineering Level 1 and need to move to Engineering Level 2. Instead of physically moving the computer or rerouting wires, simply modify the VLAN configuration of the port, changing it from Engineering Level 1 VLAN to Engineering Level 2 VLAN. This flexibility allows you to create logical, rather than physical, groups of users.



If a PC from the Engineering Level 2 VLAN is affected during a cyberattack, it is very easy to isolate the offending PC from network traffic; namely, move it to a separate, less critical segment, causing little or no impact to other network traffic. Conversely, devices or end users can easily be moved to other segments, removing them from danger of attack.

Configuring A Virtual Private Network for optimal security

A virtual private network (VPN) creates a network extension that behaves as if it were part of a larger, enterprise-wide network. As an example, VPNs allow users to reach work-related emails with a laptop computer from the convenience of a home network. Unlike a VLAN, a VPN is able to provide a secure network infrastructure. A typical VPN uses existing network infrastructures, including the Internet, to make a connection.

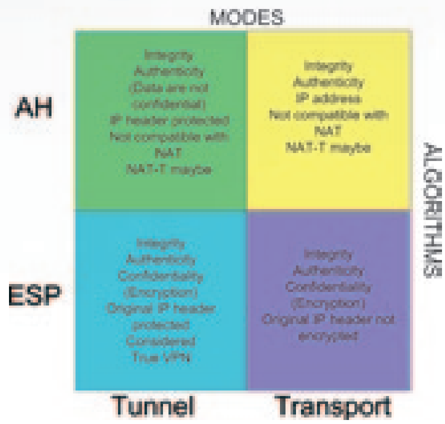
If configured properly, the security of the VPN allows the data to maintain confidentiality and integrity. VPNs create secure communications links between remote locations, while providing the same level of security as if the connection were part of a fully trusted network.

There are two types of VPNs: trusted and secured. A trusted VPN allows computers in different locations to be members of a common local-area network (LAN) with access to the network resources located within its constraints. A trusted VPN does not establish privacy. A secured VPN uses cryptographic tunneling protocols to provide security. Confidentiality, sender authentication, and message integrity establish security within a VPN. As mentioned previously, VPNs must be set up correctly in order to ensure information security. By implementing the correct security technologies provided by VPNs, it is possible to prevent unauthorized data transmission to critical infrastructure devices as well as avert the interception of authorized data transmissions, such as passwords, between these critical devices.

Despite their popularity, VPNs have limitations, as is true for many security technologies. Organizations should consider that the use of VPNs requires a solid understanding of network security issues as well as careful installation and configuration to ensure security over a public Internet network. Also, it is important to recognize that the performance, reliability, and resiliency of a public, Internet-based VPN is not under the utility's control. Instead, a VPN that uses the public Internet relies on the service provider and their quality of service. In the recent past, mixing and matching network devices in a VPN resulted in technical issues that would drop communica¬tions due to vendor incompatibility.

Using IPsec to Secure Communications

A VPN solution starts with two endpoints on a network and, for the purposes of this article, one endpoint that likely terminates in a substation. It is the suggestion of this author that devices residing within a substation's security perimeter terminate via an Internet Protocol Security (IPsec) gateway appliance. At present, many substation devices are unable to support a direct VPN termination, so termination occurs as part of an existing in-line network infrastructure device, such as a gateway, near the vicinity of the device.



IPsec is a framework protocol that secures data traversing an Internet communications link. The framework protocol includes tunnel and transport modes as well as the Authentication Header (AH) and Encapsulating Security Payload (ESP) security algorithms. Choosing between tunnel mode and transport mode depends on the power utility and its transmission and distribution network topology. For more traditional VPN use, tunnel mode topology creates a gateway-to-gateway (substation-to-substation) or host-to-gateway connection. In this case, host is defined as a computer-to-Internet device, and gateway is a network device that connects two Internet communications links.

Transport mode authenticates the two network hosts or peers and establishes a secure communications channel.

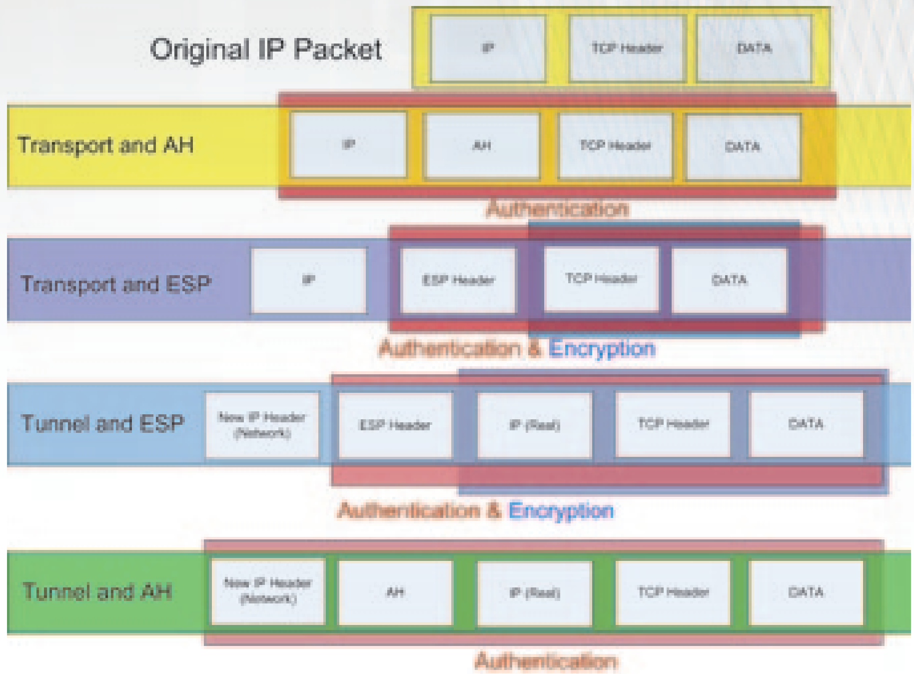
This secure channel ensures that communication between the two computers remains tamper-free and private. In transport mode, the Internet Protocol (IP) header is sent in the open.

Tunnel mode secures traffic routed between two gateways over an untrusted network. A device at one site (substation) must communicate to a device at the other site (substation). The traffic passes through the IPsec gateway. Tunnel mode is for site-to-site communications, useful for securing gateway-to-gateway, server-to-gateway, and server-to-server communications.

Configuring IPsec connections for a power utility starts with defining a set of security associations (SAs). Each SA is filtered based on source and destination addresses (IPv4 or IPv6), name (user ID or system name), Transport Layer Protocol (Transmission Control Protocol (TCP) or User Datagram Protocol (UDP), and source and destination ports (port number). These SA selectors help determine the eligibility of inbound or outbound traffic for association with a particular SA. IPsec supports strong cryptographic authentication and encryption of data.

During a cyberattack, IPsec VPN traffic traveling through a router is filtered so that any frames an attacker forms and attempts to send to a substation computer are dropped. The packets do not pass because the frames fail authentication and/or decryption. An encryption/authentication key must be used to code all data, and the network devices accept or deny this traffic.

IPsec issues arise due to the misconfiguration of the tunnel during setup, which introduces security holes. For example, implementing a traffic filter without any authentication verification on the packets could allow a knowledgeable attacker to send malicious TCP/IP traffic that matches the expected traffic profile.



Thus, the rogue traffic survives filtering. A hacker is then able to pose as a legitimate device on the substation network, and malicious traffic can be sent to the substation device by faking or spoofing the IP address.

The cybersecurity technologies described above offer a sensible yet robust arsenal to help protect and control substation network data that traverses untrusted network paths. The modern substation automation professional should be aware of and explore the use of technologies, such as firewalls and VPN IPsec tunnels. These and other technologies help protect networks from malicious traffic and provide network resiliency. There are also new technologies that look promising for application into control system security, namely the use of certificates such as X.509 and certificate services such as Online Certificate Status Protocol or OCSP.

Also, readers might consider Lightweight Directory Access Protocol or LDAP (RFC4510) as a technology that works with certificates for authentication even user-based access controls. It is important to take the time to review the application of all new security technologies to assure they do not negatively impact the safety, reliability, and resiliency of grid operations. We have many tools to consider, and we must move wisely and circumspectly forward, not compulsively or under duress; we must rely on well-disciplined engineering principles to arrive at sensible cybersecurity. ■

About the Author

Dwight Anderson received his B.S. in electrical engineering from Stevens Institute of Technology. He is now a security engineer for Schweitzer Engineering Laboratories, Inc. in Pullman, Washington. Prior to joining SEL in 2005, he worked 20 years for Hewlett-Packard as an aerospace and defense business development manager and systems engineer on projects ranging from electronic warfare countermeasures to SCADA system programming. He holds the Global Security Essentials Certification (GSEC) from Global Information Assurance Certification (GIAC), is a Certified Information Systems Security Professional (CISSP), and is an active member of the Palouse Chapter of the ISSA (*www.palouse-issa.org*).

Meter Data Management is for Cooperatives Too!

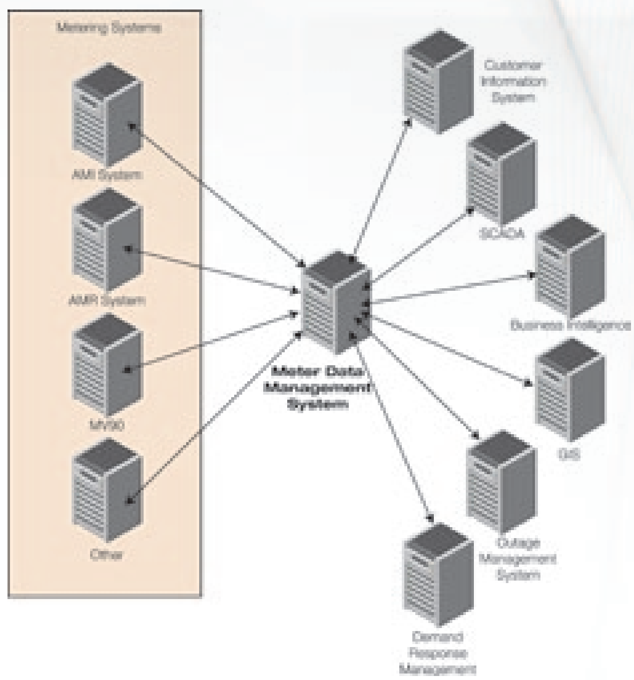
By Andrew Horstman, Manager of Load Response Wabash Valley Power Association (Indianapolis, Indiana USA)

Wabash Valley Power Association (WVPA) is a Generation and Transmission (G&T) utility based in Indianapolis, Indiana providing wholesale electricity to distribution cooperatives in Indiana, Illinois, Michigan, and Missouri. Like many utilities in today's marketplace, WVPA is always searching for ways to reduce and control energy costs. One of the ways to do this is through an active Demand Response program.

However, today's needs for demand response are more than the traditional direct load control programs that have been in place for years. WVPA not only needs to be able to shed load for system reliability and times of high peaking cost, but also needs the ability to do it in a predictable, reliable, and measureable manner. By being able to accurately measure the response to an event, WVPA expects to be able to aggregate the individual resources and possibly bid them into the wholesale demand response markets.

WVPA's member cooperatives were also looking for similar solutions. As entities that focus heavily on customer service and satisfaction, some of these cooperatives were trying to decide how best to utilize the large amounts of data being provided by their newly installed (or currently being deployed) AMI systems. The expectation of many of these utilities was that the implementation of a meter data management system would enable them to analyze and utilize the AMI data more productively, and therefore, create new operational efficiencies while providing even better and more automated customer service.

To facilitate meeting the needs of all parties, Utility Integration Solutions, Inc. (UISOL) was engaged to gather requirements and manage the overall RFP process. The company had previously worked with another G&T utility headquartered in Maple Grove, Minnesota – Great River Energy – to develop their MDM requirements.



Meter Data Management History

Meter Data Management (MDM) systems have emerged as a necessary component of an overall Advanced Metering Infrastructure (AMI) implementation. They are essential in enabling new billing methods and rate plans, providing data analytics, and enhancing customer communications. As the meter data information hub, they are critical in isolating interfaces between AMI systems and other utility systems that must assimilate and use the meter data. This reduces overall integration costs and individualizes integrations so that technology changes and system upgrades can be handled in a more efficient manner with less overall risk.

MDM solutions were first deployed at larger utilities. In these instances, the integration costs were actually the larger part of the budget, as most of these interfaces involved custom development. However, these costs could be spread over a larger number of endpoints, thereby making the overall project more cost effective.

Cooperatives Need MDM

In the last two years, cooperative utilities have begun looking at MDM solutions. This is not surprising since the needs and problems regarding meter data are not based on the size of the utility and are, in fact, fairly universal. Today's Advanced Metering Infrastructure systems produce more data than ever, and every utility wants to leverage the value of that data as much as possible.

The need to utilize this data is perhaps best understood by cooperatives, as they have been quite progressive in the deployment of AMR/AMI systems. In some cases, cooperatives are already on the second or third generation of meter reading systems. A survey taken in the summer of 2009 by the National Rural Electric Cooperatives Association (NRECA) shows that 65% of cooperatives either have deployed or are deploying some type of AMI system.

For the MDM vendors, serving the cooperative market presents some problems in that the economies of scale do not allow large integration and implementation budgets. To offset this, suppliers must be able to offer a lower cost system while still allowing a level of functionality and configurability that will meet cooperatives' needs.

How can the MDM vendors meet this challenge? There are two things that should eventually enable smooth and reduced cost integration of MDM solutions. The first is the emergence of standards and interface specifications that help define system interfaces in a more universal way. The second is the fact that there is likely much more commonality of systems such as Customer Information Systems (CIS), SCADA, Outage Management, etc. These two items provide promise for overall reduced integration costs, but it is still too early to be certain about the precise amount of savings.

Early Adopters

Some cooperatives have moved forward to implement an MDM solution in order to address specific problems and needs.

When government legislation changed the time period for Daylight Saving Time (DST), Delta Montrose Electric Association (DMEA) in (Montrose, Colo.) had a big problem. DMEA had been using TOU capable meters for years. Suddenly all of these meters needed to be reprogrammed to adapt to the new DST rules. This involved a very costly and laborious process of visiting each and every TOU meter in the field. DMEA wanted a better solution. Since many of their meters were already capable of interval data, an MDM solution capable of processing interval data and aggregating it into TOU bins was a solution that addressed their problem.

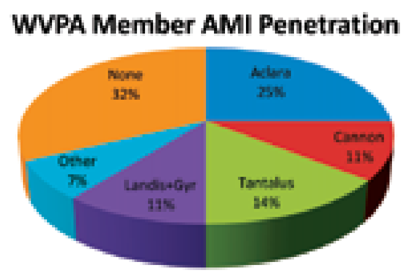
Umatilla Electric Cooperative (Umatilla, Ore.) is a distribution utility serving a large portion of the Columbia Basin and the Blue Mountain country of Northeastern Oregon. With a total meter count of approximately 20,000, Umatilla is implementing an MDM solution in order to enable TOU billing using interval data. They have been deploying AMI and MDM simultaneously.

Bluebonnet Electric Cooperative (Bastrop, Tx.) isn't implementing MDM to solve any particular problem. It has developed an overall and comprehensive approach to the smart grid, which they call the Sustainable Grid. An MDM solution is a necessary component to that vision. With a territory that lies in between and borders the outskirts of Austin and Houston, Bluebonnet is very much aware of its neighboring utilities' higher profile smart grid projects.

Bluebonnet's simple belief is that its members have the fundamental right to know their own account data. Therefore, this data needs to be readily accessible through a Web portal, an in-home display, or some yet-to-be-determined consumer interface. Furthermore, Bluebonnet believes that the availability of this data will facilitate an overall reduction in energy usage and ultimately enable a switch to a larger percentage of sustainable resources.

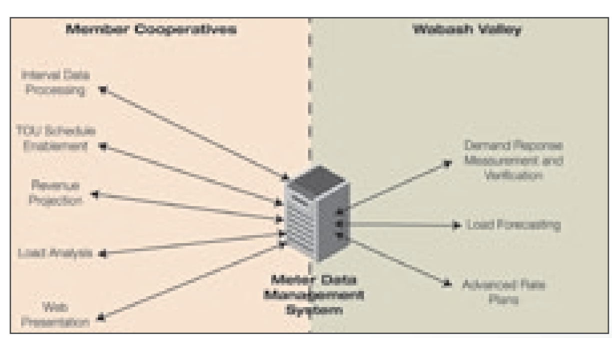
A Shared Approach

WVPA has established a shared approach to Meter Data Management. A total of 68% of the member cooperatives have deployed, are currently deploying, or plan to deploy AMI technology. (Note that this percentage is remarkably close to the NRECA national survey.)



WVPA began investigating MDM solutions in late 2008. Their interest in an MDM solution was more specifically related to enabling Measurement and Verification (M&V) of time-based pricing and demand response events. However they also recognized that WVPA could be the organization that facilitated MDM services to their member cooperatives. What has emerged is a shared implementation approach that creates a win-win solution between WVPA and its member cooperatives at a price that should be well below individual implementation costs.

The diagram below shows some of the more specific interests and objectives of WVPA versus the member cooperatives. As is shown, both WVPA and its members have a great deal of interest in utilizing the available interval data for specific purposes.



The overall goal of the shared implementation is to create a system that each utility can use as if it were their own MDM implementation, while allowing WVPA access to a selected amount of interval data across all member utilities. Under this arrangement, however, data would not be visible or shared among member cooperatives. WVPA would also not have access to additional information such as customer details, etc. This data security issue is an important aspect of the overall implementation and one that is required to gain the approval of all member cooperatives.

WVPA expects to act as the overall host for the system implementation. The initial deployment will begin in mid- to late 2010 and will include up to seven member cooperatives. The selected member cooperatives will share some commonality with respect to AMI technology and/or CIS. One of the crucial aspects of the overall success of the project will be to create a common and consistent interface for each AMI and CIS vendor and to avoid customizations, unless they are expected to ultimately be made part of the standard interface. UISOL has been a strong industry advocate of the development of standards needed to accomplish this capability and is currently facilitating interoperability testing with MDM, AMI, and OMS vendors using IEC 61968-9.

WVPA is not the only organization investigating a multi-organizational implementation. Great River Energy and North Carolina Electric Membership Corporation are also at various stages of investigation of this same concept.

A Really Smart Grid

In many ways, the proposed system will be the realization of a truly smart grid that creates better operations and efficiencies for individual utilities. However, it will also allow those efficiencies to extend beyond individual company borders and work for the common good of the Association. The ultimate goal for WVPA is to create a number of Demand Response and pricing programs that allow them to manage and control energy costs, resulting in lower energy prices for the entire Association. ■

About the Author

Andrew Horstman is the Manager of Load Response at Wabash Valley Power Association (WVPA). Andrew has been with WVPA for eight years and has worked extensively with the SCADA system there as an Electronic Engineer. As Smart Grid and Demand Response have gained importance within the industry, Andrew moved into his current position, managing these initiatives for WVPA.

The "Coming of Age" of Community Wind

By Jacob Susman, Founder & CEO, OwnEnergy Inc. (Brooklyn, NY USA)

Community Wind – the development of locally owned, utility-scale wind farms – is one of the fastest-growing segments in the U.S. wind industry. Community Wind projects are developed and owned, in part, by members of the communities in which they're developed. A typical project ranges between 5MW and 80MW, although they can range both higher and lower. Most importantly, this approach to development leads to a genuine sense of community involvement and acceptance.

Community Wind currently represents just 4% of all installed wind in the United States, though the sector is growing at a record pace – an average of 76% per year. Market share is expected to increase significantly by 2012, as the abundance of viable, large-scale sites that traditional developers require, diminishes.

While the concept of community-developed and community-owned wind farms may be relatively new in the U.S., it is a model that has been widely and successfully deployed across much of Europe. As much as 83% of wind in Denmark and 45% in Germany has been developed with local ownership. But Community Wind's success in Europe lies in stark contrast with conditions here.

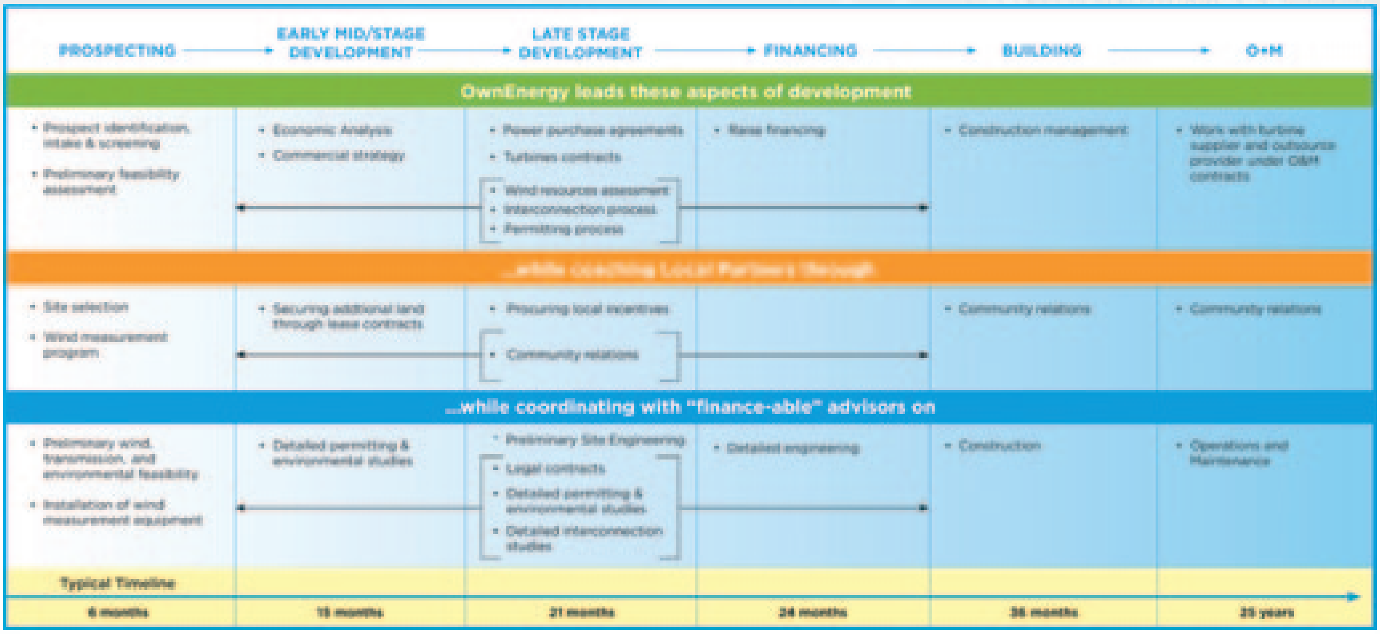
In the United States there is real concern from residents of rural communities that wind development is happening around them, but that it doesn't include them. Community Wind is a response to that dynamic that allows communities and their members to take an active role in the project and to perceive greater economic benefits in turn. With the Great Recession nearly behind us, we are charged to reinvent America's economy and recreate its energy future. Our citizens and communities can – and must – play a critical role in setting that course.

Today, a number of compelling factors have converged to create the "perfect storm" for Community Wind in the U.S. The first, and most important, factor is the creation of jobs and economic development.

Community Wind projects have been shown to have greater economic benefits and drive more job creation than large-scale "absentee" wind farms. At a time when this nation must create jobs and stimulate economic growth, Community Wind does both. Since ownership is retained in the community and profits are recycled, incremental jobs are created, along with more wages, business income and tax revenue. In fact, according to a University of Minnesota study, the economic impact of Community Wind on the local region can be as much as five times that of an absentee project

Another benefit of Community Wind projects is that they can often reach "shovel-ready" status sooner than larger, traditional wind development projects. Much of this has to do with the important role played by development partners local to the area. Community Wind projects are often smaller, tend to require less land for siting purposes and have a lesser potential environmental impact than larger projects.

Local development partners in Community Wind projects do the lion's share of the work to socialize the project, manage relationships with neighbors and secure additional wind rights required to build. Often, the local partner will customize leases and other land documents to meet local commercial conditions and requests. Having that local partner as a member of the development team can also serve to increase support for the project in the community and thereby help to reduce local opposition to the project.



Typical Community Wind Business Model

Another very compelling factor, particularly for utilities, is the issue of transmission. Our current transmission grid is straining to deliver clean energy from the rural areas where it is generated to the populous cities where it is consumed. Close to 300,000 MW of proposed wind projects are in interconnection queues.

In the face of these issues, transmission operators see value in having distributed generation on their system and having smaller generating units closer to the load. This value could come through increased system stability, power quality, and reactive power, or it might simply come from a reduced need for new power lines and/or upgrades.

Since Community Wind projects are smaller and more distributed by nature, and since Community developers site these smaller projects to avoid network upgrades, utilities are often able to connect the projects to existing grid infrastructure without building new lines or making costly transmission upgrades. In fact, in some instances, higher voltage area network transmission upgrades might be able to be deferred if wind generation were distributed over a larger area through dispersed Community Wind projects. These dynamics all compare with Absentee projects, many of which are now dependent on the creation of new large-scale transmission infrastructure. OwnEnergy estimates that the majority of these new lines will not complete construction before 2015.

There is further potential transmission value in the reduction of wind generation variability due to the geographical diversity that comes from smaller, more distributed projects. Simply stated, there will likely be fewer times when the overall wind generation on a transmission system is at zero or at full output if wind generation is distributed over a larger area. These diversification benefits increase system balance and stability and may translate into real dollars and cents, as this diversification leads to more predictable dispatch of existing conventional power stations in wind-rich areas.

Community Wind is also a more favorable way for utilities – especially Rural Electric Cooperatives – to meet their renewable generation needs, compared with Absentee wind power. Community Wind projects typically have strong support from community members, who are often also members of the local electric cooperative. They may also ease integration issues on these utilities' systems. Additionally, community projects may present an opportunity for utilities and co-ops to own their own wind generation because Community Wind projects frequently invite utilities into the project as partners. In current financing market conditions, rural utilities may also be the least expensive form of rate-based equity capital for U.S. wind projects.

One way to encourage even more participation in Community Wind by electric cooperatives would be to lower the threshold for inclusion under any Renewable Energy Standard contained in any forthcoming Energy or Climate Bill to 1million megawatt-hours served from the present 4million megawatt-hours. This would nearly double the number of co-ops and municipal utilities that are required to procure renewable energy for their members and residents.

Another important factor leading to an uptick in Community Wind is the availability of financing. In light of the drastic changes in economic conditions, smaller projects have become very attractive from a financing perspective.

Investors want to participate in mid-sized, Community Wind projects because they require a smaller investment and have relatively low risk because of local involvement and support. These projects can also often see benefits from investment by local banks and investors.

Several states have implemented policies that foster the development of community wind, including Minnesota, Maine, Colorado, Montana, and Nebraska. We expect to see this trend continue across the country. And with increasing support for Community Wind from the industry's leading trade association, the American Wind Energy Association (AWEA), Community Wind is increasingly in a position of prominence across the industry. AWEA recently created a Community Wind Working Group and hosted the inaugural Small and Community Wind Conference in Detroit, in November 2009, which attracted 2,100 attendees – the most ever to attend an AWEA regional conference. This event was truly a "coming of age" for Community Wind.

OwnEnergy is a leading developer of Community Wind in the U.S and the only venture capital-backed company in the industry that partners with local communities and landowners across the country. This model enables those individuals and organizations to have a direct stake in these jointly developed projects. It also taps into the entrepreneurial spirit of farmers, ranchers and landowners across the U.S. to develop sources of clean, renewable energy that they can call their own. With more than 50 years combined industry experience, OwnEnergy team members leverage their networks, resources and industry know-how to guide partners through the complex hurdles of wind development to get projects done.

Each partner takes an active role in the development and installation process, particularly in local aspects of development around procuring wind rights, measuring wind, conducting community and local government relations and many of the commercial processes and negotiations in development. In return, our local partners receive a meaningful ownership stake in the resulting project.

For its part, OwnEnergy manages the development process from start to finish. This includes a heavy emphasis on technical, legal and commercial development processes such as siting, resource assessment, interconnection, permitting, power marketing, turbine procurement, financing, construction and operations. ■

About the Author

Jacob Susman is the founder and CEO of OwnEnergy, the leading developer of Community Wind projects in the United States. Jacob has ten years of investing and business development experience in the field of renewable energy and has led OwnEnergy since its inception. Before founding OwnEnergy, he was a founding member of Goldman Sachs' Alternative Energy Investing group, where he was involved in Goldman's investment in Horizon Wind Energy and co-led a portfolio financing that was named Project Finance's N.A. Renewable Energy Deal of the Year.

Earlier, Jacob served as Project Manager for the AES Corporation, working on a team that developed one of the largest power plants in Spain. He also led AES's efforts to develop a Spanish renewable energy business, which included negotiation of more than 1,000 MW of wind energy investment opportunities.

Jacob holds an MBA from The Wharton School of the University of Pennsylvania, where he led a team to the finals of the Business Plan Competition with the concept for OwnEnergy.

Proper Control Room Design Facilitates Critical Thinking and Situational Awareness

By Mary Jo Nye, Market Manager – Utilities Control Room Group by AVI-SPL, Tampa, Florida USA

In today's fast-paced electric utility, there are many forms of data available for analysis in a mission-critical control room. With the introduction of Smart Grid data such as Outage management, Geographic Information Systems, Advanced Metering Infrastructure and substation automation data, the quantity of information is expected to grow exponentially.

Proper control room layout optimizes data visualization and interpretation for operations

As the electric industry is pushed to evolve, real-time visual analytics and three- and four-dimensional data will no longer be the exception but the norm. Unless the operator work environment is enhanced and the data presentation is streamlined and visually available for interpretation, an operator may be overwhelmed in an emergency. The proper planning, design and control room components (e.g., work space, networking, lighting, floor height, display wall, sound system, etc.) including the proper ergonomic alignment and layout of each component is crucial for optimal situation awareness and data interpretation.

What are the Key Components of a Control Room?

Key to the success of critical decision-making is the functional design of the control room itself. Integration firms specializing in mission-critical control room design are aware of the idiosyncrasies that contribute to a highly functional environment. Creating this environment begins with an information exchange with utility personnel who clearly understand the process, systems and applications of the control center environment. In addition to the physical components (e.g., work station and office location, lighting, acoustics, etc.), the software and other tools used by the operator must also be considered carefully. The resultant design and solution set is one that best meets the needs of the operations staff and their unique operating environment.

Within this design, there are four (4) critical factors or components to consider: Spatial, Ergonomic, Environmental and Functional, each of which is summarized below.

Spatial considerations include room size, layout of the workspaces, number of users and functional requirements. When evaluating the room size, consideration should be given to the number of workstations, individual offices, shared or common spaces, display wall requirements, and any other required equipment. Proper placement of this equipment requires analysis for the total physical space of each component as well as the appropriate line of sight.

A sight line analysis is a critical piece of any control room design to assure each user is aware of any visual data required of their operational performance. This analysis should include at a minimum, operator workstation viewing angles and display wall technologies. Combined, the proper placement of work station equipment (considering the monitor, keyboard and mouse in relation to the extended human reach) and the most favorable visual viewing scenarios (proper monitor height in relation to other work station equipment) provide the optimal work environment for control room operators.

Ergonomics is the study of the relationship between workers and their work environment and is an integral piece of the control room design. Operator positioning and comfort contribute to proper data interpretation. With the emergence of computers in the work environment, individuals spend more time in static positions while undertaking repetitive tasks. Proper ergonomic design minimizes the inherent risks of repetitive tasks, awkward posture and maintaining of a certain posture for a prolonged period of time.

Workspace design should allow the user to move and or change positions throughout the day. Useful ergonomic considerations include flexible mounting of fixtures for monitors, telephones, shelving and other accessories. Swivel arms allow movement, both vertically and horizontally, for monitors to accommodate a wide range of sightlines. Proper height, width and depth of workspaces will comfortably accommodate the knee space up to the 95th percentile for male operators. Proper positioning of lighting reduces glare on the monitors, thus reducing operator eyestrain. Providing the proper work environment is proven to increase productivity, improve work quality, heighten worker satisfaction, and most importantly, reduce or eliminate human error.

When designing a control room, consideration should be given to the **environmental** impacts in the room. These include the acoustics, electrical/HVAC and lighting. Proper design of the acoustics ideally suppresses all reverberant, mechanical and other noises of the area. The room should ensure speech privacy while controlling ambient noise levels and containing the electronic system noises from adjacent spaces. Redundancy, power conditioning (e.g., surge, EMI/RFI filtering), power circuit delay and sequencing, and proper grounding and bonding of electronic system components contribute to proper electrical design.

The HVAC system should handle the heat load of the electronic systems and control the temperature and humidity levels to remain in compliance of the electronic system specifications. Ideal ambient room temperature is recommended between 70 and 72 degrees F. The relative humidity of the area should be 45-65% with air movement less than 4 inches to 6 inches per second. Lighting can bring some unique challenges. Most times, control rooms use indirect light where the ceiling is used to reflect the light downward.

The ceiling reflectance value should be 0.8 or greater. Ideally, walls should be covered with a matte finish with a reflectance value of 0.5 to 0.6 and be off-white in color. Floor coverings should have a reflectance value of 0.2 to 0.3 for carpet and 0.25 to 0.15 for tile. Adjustable task lighting is recommended at each operator work position. If the room includes a display wall, any lighting in front of this wall should be greater than 40 foot-candles.

Many control rooms are enhanced with the addition of display technologies. These technologies allow improved visual representation of data, which can accelerate insight and interpretation, particularly at crucial moments. Special consideration should be given to equipment used in mission-critical applications since not all video panels are manufactured for 24x7 operation.

Equipment such as LCD panels can easily be tiled together to create a display wall. While this equipment is readily available and less expensive than rear or front-projection systems, these panels are not made for 24x7 operation.

Since these panels do not create a scalable image due to the larger mullion between panels, the operator is required to concentrate harder to interpret the data. Additionally, if static images are displayed for a prolonged period of time, the panel will create shadows of this image or suffer what is commonly referred to as "burn-in," which is exacerbated by the persistence of the screen itself.

Front projectors – commonly used in boardrooms – are an option, but with some limitations. While they allow visualization of schematic, geographic and other types of displays, not all are rated for 24x7 operating environments. Also, the cooling fans asociated with projection-style displays can be an annoying distraction in the control room environment where concentration is of paramount importance. Front projectors will also require manual maintenance in the event of a malfunction, another potentially disruptive reality.

Video display cubes offer many attractive options including a range of technologies (i.e., LCD, DLP, etc.); multiple configurations and sizes; many resolutions; zero mullion design; and light, color and brightness management. These systems can be expanded to include audio and visual equipment, and can provide for inclusion of live video feeds such as news, weather and security cameras. Maintenance advantages of video cube displays include redundancy of components and lamps, automatic color reconfiguration and brightness modification.

To enhance the capabilities of the video display wall, software is often integrated to manage displays and provide flexible video feeds. This software offers advanced wall management control by interacting with the content sources to place the content on the wall. It also provides control of the data feeds for cameras, news and other visual content. Optional features are available to provide "screen scraping" of displays from other systems or to assign areas of the wall to specific users.

Adding data visualization software – software that inter-operates with the video display wall and wall management software to further improve the quality of the content displayed – is a key component to a successful display wall solution. In fact, it is the content that aids the operator in decision-making; not the hardware or the software.

So rather than scaling the existing data to create a larger display, the data can be built and enhanced for better and quicker analysis and may incorporate other tools such as graphics, charts, trends and symbols.

Exercising proper placement and consideration of each individual control room component leads to a work environment that is free of obstacles and that includes clear and unobstructed views of operational data while providing optimal situational awareness.

Critical Thinking and Situational Awareness

Critical thinking – as defined by noted authors Alec Fisher & Michael Scriven – is "skilled, active, interpretation and evaluation of observations, communications, information and argumentation." Situational awareness (as defined by Wikipedia) is "the perception of environmental elements within a volume of time and space, the comprehension of their meaning and the projection of their status in the near future." By applying these concepts and principles to the control room setting, operators are empowered to make decisions based on the information provided to them. In order for them to make effective decisions, it is imperative that they are provided with the required information, that the information comes from all necessary sources, that the data is received in a timely manner and that there isn't any question as to the quality of the data.

Enhanced Decision Making and Situational Awareness

To enhance decision-making and improve situational awareness, map boards have traditionally been a useful control room component. As the need for more data moves into the control room, it is imperative that the operations staff has the proper tools available to improve processing and interpretation of this data.

Currently, control rooms use various kinds of display wall tools. These tools include metal or mosaic tile walls (including some with indication lighting), large-scale paper drawings and maps, electronic panels, (LCD or plasma), front projectors and front- or rear-projection video systems. And, it is not uncommon for control rooms to incorporate some or all of the above in various combinations.

The large static display walls typically represent a schematic view of important service areas or an entire service territory. While this comprehensive view is useful, it doesn't offer real-time views or current system status. An operator still needs to interpret data from a workstation console and/or the wallboard and then mentally combine this data prior to deciding on a proper response.

When a static wall incorporates LEDs or digital displays, it begins to add a situational awareness dimension. This added functionality contributes to the functionality of the system by adding a dynamic dimension to the schematic view of the system. However, simple indicators are often limited in purpose and may not change in real-time as system changes occur. That is, the operating staff is still required to process data provided from multiple sources, as above.

By contrast, video display wall technologies can show multiple data images, providing a comprehensive real-time view of current system status. System schematics, geographic system representations, news and weather feeds, and video camera data can all be shown simultaneously. The operator is able to see, understand, analyze and then interpret the data quickly.

Today's software technologies allow 2-, 3- and 4-dimensional images and give the control room operations staff the ability to view displays from many different systems. This data can be integrated into one display to obtain an enterprise wide-area view of current system status. For example, GIS map data can be displayed with real-time updates from SCADA and real-time weather maps to predict how an incoming storm may disrupt services. indeed, as Smart Grid data applications are introduced and multiple forms of data are made available for analysis, the push for advanced display tools and technologies will likely accelerate. And, as technology is added to the grid, the expectation for improved customer service will likewise be heightened.

Conclusion

To enhance decision-making and improve situational awareness, map boards have traditionally been a useful control room component. As the need for more data moves into the control room, it is imperative that the operations staff has the proper tools available to improve processing and interpretation of this data. ■

About the Author

Mary Jo Nye joined the Control Room Group by AVI-SPL in 2009 bringing more than 11 years experience in the electric utility industry. Her work has concentrated on the design and deployment of SCADA/Energy Management System (EMS), Distribution Management Systems (DMS) and real-time cyber security solutions. Mary Jo can be reached at +1 813-451-4691 or via email to: *maryjo.nye@avispl.com*.

Volume 2 No. 1

The Bigger Picture

Interconnection Queue Wars

By Gregory K. Lawrence, Partner; McDermott Will & Emery LLP (Contributing Editor)

The rush to secure interconnection rights for renewable energy projects is well underway, spurred by significant, and often time sensitive, governmental incentives for renewable energy. With the incentives have come multitudes of renewable projects that request interconnection to transmission grids nationwide. Entering the interconnection queue typically requires demonstrating site control and/or paying increasing deposits to maintain queue position until site control is established.

The competition for government incentives and interconnection slots has created a land rush, tempting early stage projects to possibly cut corners on site control including securing and submitting possibly incomplete or inaccurate lease agreements for renewable energy generating sites. This land rush could create complaints to grid operators and regulators over projects in a highly competitive queue that may lack sufficient site control or economic viability if the transmission upgrades anticipated for other projects in queue do not come to fruition.

Robust Incentives

That the renewable energy gold rush has begun is undeniable. For example, 8,558 MW of new wind generation capacity added in 2008 was 43% of all new U.S. energy generation, and another 4,000 MW was added by mid-year 2009 – and that was before the incentives provided in the American Recovery and Reinvestment Act (ARRA) and the Administration's 2010 budget had fully begun. From 2009 through 2012 a significant total of 40,400 MW of new wind generating capacity is anticipated, according to the U.S. Department of Energy.

Driving the process is not just the availability of incentives, but also their accelerated timeframes. The ARRA extended the placed-in-service date for the renewable energy production tax credit (PTC) through 2012 for wind projects and through 2013 for other renewable sources. It also allowed projects placed in service by 2012 (wind) or 2013 (other renewables) to receive an investment tax credit (ITC) immediately rather than over a 10-year period, and allowed renewable energy developers to elect a non-taxable cash grant equal to 30% of total facility cost (essentially replacing, for a time, the currently dormant tax credit monetization market), if construction on the facility commences in 2009-2010 and is completed by 2013 (wind), 2017 (solar) or 2014 (other technology).

Add to this the ARRA's Conventional Renewable Energy Loan Guarantees, and the important financial incentives for accelerated renewable development are implicit.

Other accelerants are the mandatory Renewable Portfolio Standards (RPS) that in approximately 30 states and the District of Columbia set required minimal – but quickly increasing – levels of renewable energy use. The Waxman-Markey Bill passed by the U.S. House of Representatives in June 2009 sets national renewable energy generation targets that rise to 20% of all electricity by 2020.

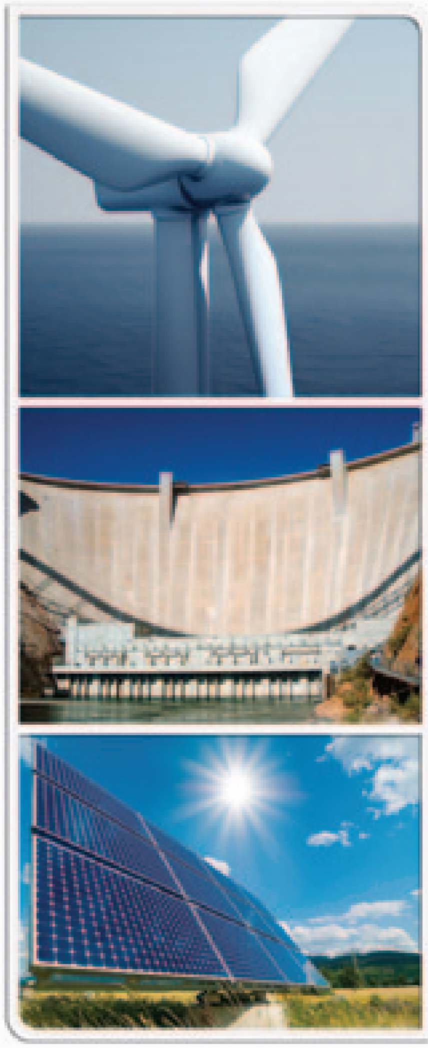
The Senate and House are considering legislation to put a price on greenhouse gases, including fossil power generation emissions. And the Environmental Protection Agency is not waiting for Congress to act – it is requiring facilities that account for up to 85% of U.S. greenhouse gas emissions to submit annual emission reports beginning in 2011 and has proposed significant permitting rules for emitters including the use of best available technology. Putting a price on carbon emissions will tend to make renewable power more competitive, providing a further, compelling development incentive.

Robust Due Diligence

These forces highlight the need for robust due diligence to ensure a successful renewable project. In addition to standard diligence regarding offtake agreements, permits and project development documents, a typical project should be assessed by available transmission capacity and interconnection opportunities and their cost. Instead, under pressure to enter the queue before competing projects secure their place, documentation of site control might be assembled haphazardly.

Although straightforward, the typical requirements for demonstrating site control to make an interconnection request are open to some level of interpretation. To enter either the Preliminary or the Definitive Interconnection System Impact Study queue in the Southwest Power Pool, for example, the interconnection customer needs to provide some evidence of ownership in or rights to use or acquire the site of the proposed generating operation. There also needs to be demonstration that the amount of land under control is sufficient for the generating operation. However, if the developer can provide a reasonable layout involving less land, it may be accepted. In addition, the interconnection request can secure a place in the connection queue by payment of an initial deposit and additional deposits ranging from $40,000 to $150,000, depending on the type of study and the size (MW) of the project.

The Midwest Independent Transmission System Operator (MISO) requires additional documentation, including demonstration that there is land area equal to at least 50% of that required to support the size and type of proposed project. MISO requires that proof of site control include copies of relevant portions of land lease or purchase documents, as well as a signed statement that all of the listed agreements are recorded in their entirety, that all referenced land is within the proposed project boundaries and those agreements constitute 50% (or more) of ownership/control of the project's total site area. If MISO determines that proof of site control has not been adequately met, or that the developer has made false representations, the interconnection application must be withdrawn with loss of queue position.



Such provisions are critical, but they do not address completely the possibility of errors in the title or the execution of option and lease agreements for the property. There also could be issues with recording the various lease agreements with the proper land registry. Finally, even if such land agreements are viable or have minor errors, the developer still may have property access issues that could negatively influence the project. All of these factors could make a project developer's efforts to prove site control more difficult, which could lead to disputes between project owners and transmitting utilities, and between generation projects fighting for position in the queue.

The Federal Energy Regulatory Commission (FERC) has launched initiatives to have grid operators assess and improve the processing of their interconnection queues, including queue size, processing timeframes and backlog assessments. The underlying issue, however, is vigilant due diligence, and not only processing time. Given the important incentives to renewable energy development, regulators, grid operators and developers should beware that failure to document fully and accurately land rights could mean controversy and a failed project. ■

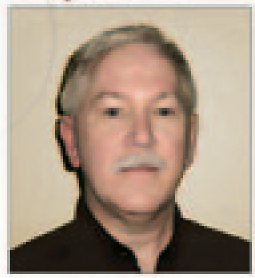
About the Author

Gregory K. Lawrence is a partner in the Energy and Derivatives Markets Group of global law firm McDermott Will & Emery, and leads the firm's Global Renewable Energy, Emissions and New (GREEN) Products group. Mr. Lawrence focuses his practice on regulatory proceedings, negotiations, governmental affairs and agency litigation relating to the wholesale and retail electricity and natural gas industries.

SECURITY SESSIONS

Volume 2 No. 1

With William T. (Tim) Shaw, PhD, CISSP



Not too long ago, on one of the SCADA cyber security blogs that I routinely monitor, this interesting question was posed: What is the difference between "security" and "compliance"? It's a relevant question because as of today, most 'entities' that are subject to the NERC CIP guidelines need to be in compliance with those requirements, since the schedule of implementation issued by NERC requires them to have achieved "compliance" – and for some, "auditable compliance" – right about now.

In a prior column I provided this dictionary definition of Security: Safety; freedom from worry; protection. By contrast, the definition of Compliance is: The act or process of complying to a desire, demand, proposal or coercion; or alternatively: Conformity in fulfilling official requirements. In my experience, I've found that compliance is frequently addressed as a mixture of the two definitions. Very often it amounts to a legalistic strategy whereby an organization does just enough to meet official requirements under threat of legal and financial coercion.

In the case of the NERC CIP rules, it appears that some utilities may have taken the approach of doing just enough to claim compliance in order to avoid being hit with huge fines and also to be able to claim due diligence and proper governance in a court of law, should a legal question or challenge ever arise. The salient point here is that security and compliance are very definitely not synonymous.

One would hope that well-intended official requirements such as the NERC CIP rules would – if properly addressed and implemented – lead to being secure. However, that may not be the case. Without a doubt, the underlying objectives of the NERC recommendations – starting with the original NERC-1200 and NERC-1300 standards and now, the CIP rules, have all sought to provide guidance and to suggest best practices for establishing acceptable levels of security for critical infrastructure assets.

Among the most often voiced concerns about the CIP guidance is that it leaves far too much to the unilateral discretion of the target entities. There are several areas where the rules get highly specific, such as requiring port scanning. But others – such as the selection of an assessment methodology – leave the interpretation of the rules (as one of my college professors used to say) "to the reader as an exercise." This has created a firestorm of arguments and articles about what NERC could/should do to improve the CIP guidance.

Realistically, a tightly specified 'one-size-fits-all' approach would have been far worse than what we have, and I can imagine that it would have generated just as much, if not more, controversy and debate. I have always interpreted the NERC approach as allowing the various entities to have the flexibility needed to adjust their compliance response, within a limited range of variability, for their particular situations. But the question remains; if you comply are you also secure? If all an organization has as their objective is the minimum required necessary to achieve legal compliance, then the odds are good that their actual security level won't be all that great.

One of the reasons many organizations fall short of achieving a (legitimately) secure environment is that effective security requires a management commitment and ongoing management and employee support.

If employees sense that management is treating security as just another bureaucratic process to be endured, they won't ever take it seriously. And that is a very big mistake – one that can actually expand vulnerability rather than diminish it.

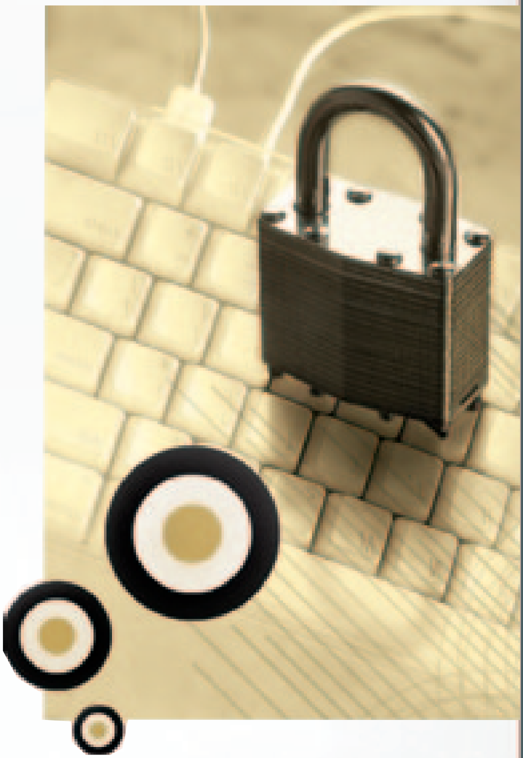
Many of the technical and physical mechanisms (i.e., security countermeasures) put in place for the purpose of cyber/electronic and/or physical security can be inadvertently – or in some cases, deliberately – neutralized by the imprudent actions of an employee. Passwords are a good example. That is, if employees think security isn't important, they won't worry about following the IT department's suggestion of picking hard-to-guess passwords, mainly because that usually makes passwords harder to remember. And, writing them down and leaving the password in obvious places – like on a sticky note slapped onto a PC screen – is another no-no.

Likewise, if no one really worries about security then why bother making doubly sure that doors are locked or that sensitive information is properly disposed of, not to mention obsolete company computer equipment? Remember, poorly trained, uninformed or unmotivated employees can easily neutralize all of that money spent on the effective security hardware, software and procedures. Bottom line: A password like "password" is no protection – nor is a lock that isn't locked!

One of the reasons that most of the individual CIP standards specify that a senior manager (or delegate) must "review and approve" security policy is to elevate the visibility of security to a management level and make at least the designated senior manager accountable for security. Security is not a one-shot process. Whatever you put in place last year may not be adequate next year, based on changes in technology, changes in your business objectives, or changes in the security "threatscape" as it is sometimes called.

So, in order to remain secure you need an evolving security management program; one that has committed staffing, a firm budget and management priority. If security concerns and objectives are not treated as one of the annual business processes and employees are not periodically reminded to consider security as part of their daily job requirement, security effectiveness will suffer. On the other hand, a well-trained and motivated employee base can significantly improve overall security, quite possibly more than any other factor or strategy.

On another front, we often make the mistake of thinking that cyber attacks on computer systems depend solely electronic communications vulnerabilities. While that is certainly one dimension of cyber attacks, it is usually the final step – not the first one. In preparation for an attack, the perpetrator(s) will usually have already spent considerable time and effort gathering information for the ultimate attack using a range of reconnaissance methods.

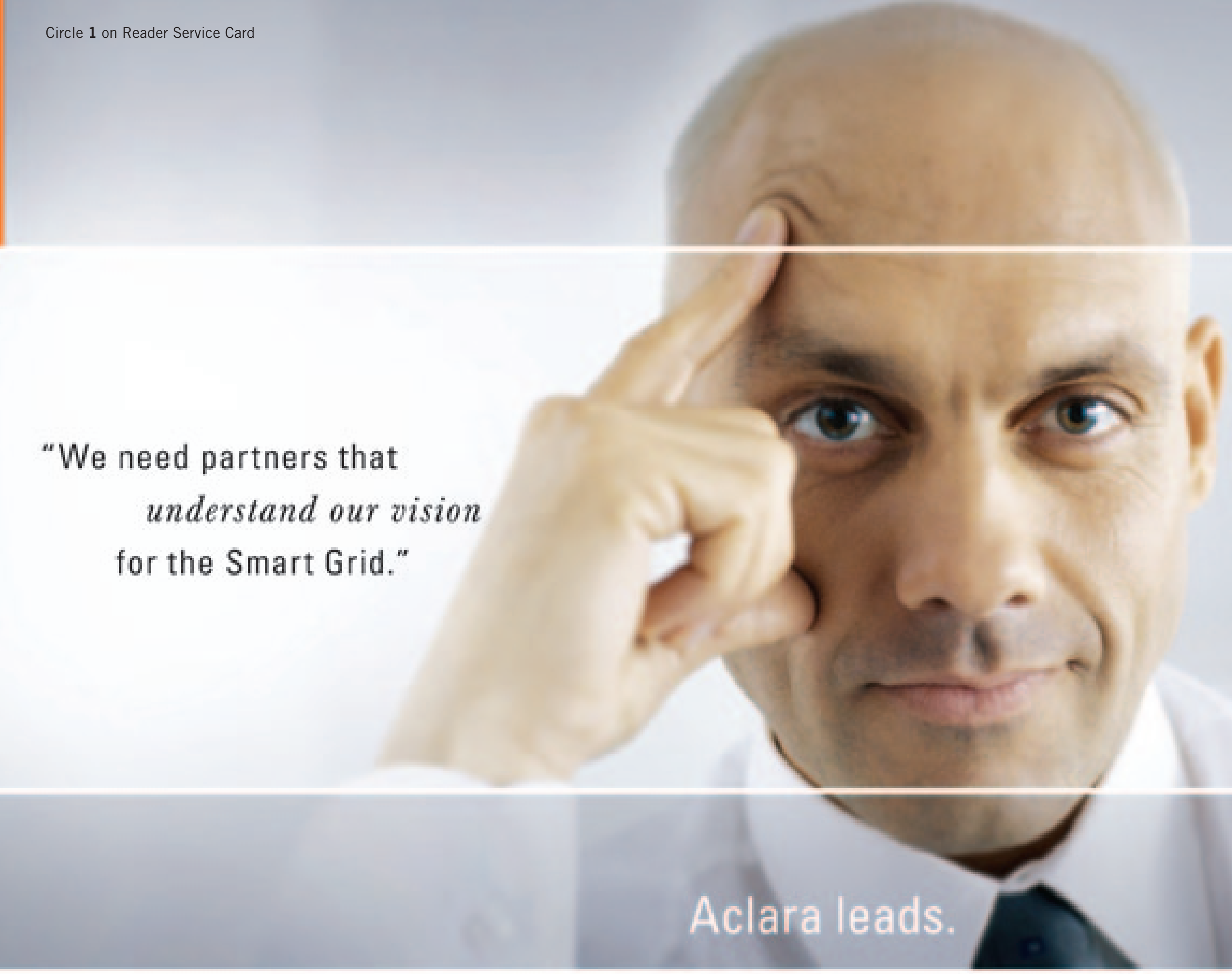


Devastating and well-publicized cyber attacks against commercial firms often have been successful because the attackers used so-called "social engineering" techniques to gather vital information prior to launching the electronic attack. Stealing or buying a company computer, going through the company dumpster, calling in to the various departments, tricking people into giving out passwords and even physically entering the company facilities are all tactics that have been successfully used to gather information that enables successful attacks. It is likely that someone planning to attack a SCADA system will learn from those successful commercial attacks and try the same strategies. However, a well thought out security policy that provides clear guidance and specific rules for employee behavior can help thwart these common data gathering methods.

Operational security is the general term and category most often used to encompass things like employee training and motivation, use of background checks and the administration and enforcement of company policies and procedures. They are also sometimes referred to as Administrative Countermeasures. Operational security is but one of the three main aspects of overall security, along with physical and cyber/electronic security. It is a necessary and vital component of a security program and at the forefront of several of the NERC CIP rules. But, more on that in a future column... ■

About the Author

William T. "Tim" Shaw (PhD, CISSP) has been active in industrial automation for more than 30 years and is the author of Computer Control of BATCH Processes and CYBERSECURITY for SCADA Systems. Tim has contributed to several other books and is a prolific writer and presenter on a range of technical topics. He is currently a senior security consultant for SecuriCon, an information security solutions firm, based in Alexandria, Virginia. Tim has been directly involved in the development of several DCS and SCADA system products and regularly teaches courses for ISA (International Society of Automation) on various topics. Inquiries or comments about this column may be directed to Tim at *Tim@electricenergyonline.com*.


"We need partners that
understand our vision
for the Smart Grid."
Aclara leads.