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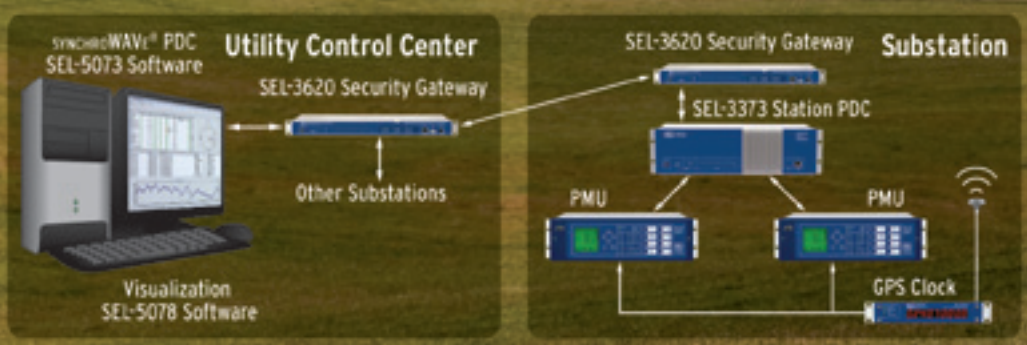

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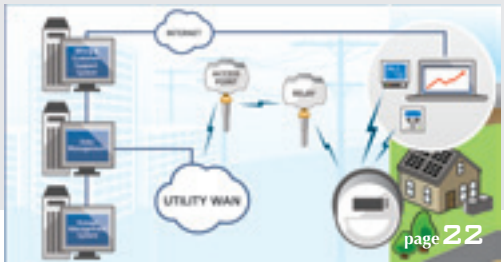

page 22


page 24

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Michael A. Marullo, Editor in Chief

Smart Grid Meets Katrina… Déjà vu all over again!

I've been hearing and reading lately about how the Stimulus – or the American Recovery and Reinvestment Act (ARRA), if you prefer – isn't working. People are up in arms about the lack of jobs that were promised, and understandably so; hey, no one likes a prolonged recession. And by the same token, the funds earmarked for energy initiatives and Smart Grid projects – nearly $4 billion of the $787 billion ARRA total – don't seem to setting things on fire yet either.

By the time you read this we will have observed the fifth anniversary of the worst natural disaster in U.S. history – Hurricane Katrina. I guess you might say that we're doing all right under the circumstances, but after watching helplessly as BP's blown out Deepwater Horizon rig spewed millions of gallons of crude oil into the Gulf of Mexico for over three months, we're still a long way from being able to say that we're okay.

But this isn't going to be a column about hurricanes or oil spills. It's a column about realities – the kind that most people don't like to face. It's about how things really work, not the way we'd like them to work in a perfect world. That said, let us hearken back to that early post-Katrina mindset, just a few months after Katrina devastated the Gulf Coast and submerged New Orleans for weeks in the aftermath of catastrophic levy failures in and around the city. As the nation and the world was wracked by the scale and enormity of the damage, it became increasingly clear that the recovery would take years – and billions of dollars – to even begin to put things right.

It was at this point that the U.S. Congress "sprang" into action, announcing billions in recovery dollars. I remember thinking at the time how fortunate we were to live in a country where, despite our frequent and sometimes divisive differences at the local, state or regional level, we could still come together in a crisis for the common good. But rather than breathing a sigh of relief, this would prove to be the beginning of a long and painful lesson in the workings of bureaucracy – one of those nasty realities we'd much prefer to ignore.

When that initial funding – about $10 billion as I recall – was announced, I was quite optimistic that we would see a wave of unprecedented recovery projects sweep across the region in a matter of a few months and that we would soon be, if not entirely back on the road to prosperity, at least within walking distance. In fact, we were promised that very thing by politicians at virtually all levels of government, from the president to the governor to the mayor. They were all atwitter about how fast we would see this massive transformation take place. We were all ready to be dazzled.

So, we waited, and waited, and waited. Weeks turned into months, and quite unbelievably, months turned into years. "How can this be taking so long?" we all wanted to know. But strangely, no one could offer a credible answer.

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Michael A. Marullo, Editor in Chief

Smart Grid Meets Katrina… Déjà vu all over again!

Then, many months after the announcement of the funding was made with much fanfare, we were told that the funds were still stuck somewhere in the "system" and had still not made it past the state level. (This is a system?)

Without going into what amounts to a protracted story of government bureaucracy, inefficiency and ineptness, let it suffice to say that it was nearly THREE years before a substantial portion of that recovery funding was actually spendable. And despite being told almost daily by our government leaders and the press that the "billions" were just around the next corner, it has to this day – nearly five years later – failed to produce the wave of construction that was originally promised.

I'm not writing this just to whine about the way the Katrina recovery scenario has played out, but I do want to point out that as that tired cliché states: *The wheels of progress DO turn slowly.* Frankly, I don't think most people realize just how slowly that can be where government and/or institutional bureaucracy is involved. Regardless of how well intentioned the individuals involved might be, things – especially really big things – take time to produce meaningful results.

And just because we don't like things taking time in our mostly instantly gratified world, they just do; which brings me back to Smart Grid and Stimulus funding…

Naturally, we all want answers to why things aren't moving faster, and we want them now! Keep that goal in mind as you read this quick chronology of the ARRA Smart Grid funding progress to date:

- **FEB 2009**: President Obama signs the ARRA ("Stimulus") Bill into law
- **OCT 2009**: Obama announces $3.4 billion* in Smart Grid Investment Grants (SGIGs) to fund 25 large and 75 smaller projects to help build a smarter electric grid
- **MAR 2010**: Glendale Water & Power becomes the first city in the country to sign a Smart Grid Investment Grant contract. (Still no spendable funds, however.)
- **May 2010**: Glendale receives the first check from the Department of Energy (Note: This occurs 15 months after the ARRA passage; 7 months after the first funding announcements; and 2 months after Glendale's contract signing – and it's just the FIRST payment out of $3.4 billion!

(*Ranging in size from $400,000 to $200 million (per award) and augmented by up to $8 billion in utility matching funds, these grants are intended to fund a vast array of Smart Grid projects and are expected to create "tens of thousands of jobs" including those associated with the deployment of some 18 million smart meters.)

Okay, so now it's September. How long do you suppose it might take after a utility gets a check in hand – the paperwork necessary to be able to actually spend it notwithstanding – to move those funds into the economy, or more importantly, start creating new jobs? A month? Six months? Possibly even a year or more? Let's be really optimistic and assume it takes just 60 days. That means that the Glendale money would be hitting the local economy… yep, you're correct, right about now – and remember, we're being very optimistic here! (Reality bites, huh?)
Or, looking at it another way, let's assume you got a "mere $200 million" poured into your local economy. Assuming that you don't live in NY, LA or some other gigantic metro area, do you actually think it wouldn't leave a mark? Next, multiply that $200 million by 60 (i.e., $4 billion in ARRA funding plus $8 billion in utility matching funds = $12 billion), and you'll get an idea of how much money is being pumped into the economy – just for Smart Grid projects. Following this logic, you'll need to multiply that $12 billion by 65 to get to the full $787 billion ARRA total.

So how much of THAT money do you suppose has actually been received and deployed so far? Hmm, this is like déjà vu – all over again! – ***Ed.***

P.S. As we went to press, the evening news headline on New Orleans TV was that all BP Oil Spill claimants would need to completely re-submit their applications to the federal claims manager – to "help streamline" the process. I rest my case…

Industry NEWS

LumaSense Completes Acquisition of Opsens Inc.'s Fiber Optic Technology Used to Improve Transformer Reliability and Management of Grid Assets

Move Signals Transformer-Measurement Market Consolidation and Points to Increased Demand for Smart Grid Reliability

– LumaSense Technologies, a global provider of temperature and gas sensing solutions, announced it has acquired fiber optic sensing technology from Canada-based Opsens Inc. (TSX-V: OPS) used to help energy companies identify transformer hot spots and perform critical high-voltage equipment temperature monitoring. The deal for Opsens' PowerSens system gives LumaSense a well-rounded fiber optics portfolio designed to help utilities improve power grid reliability involving generation, transmission and distribution assets.

"As global energy demand increases, transformer and electrical asset reliability is a growing priority," said Vivek Joshi, LumaSense Technologies' chief executive officer. "Transformer makers and utilities are looking for a wide range of options for improving system reliability across all sizes of transformers, distribution units included. This type of technology truly enables the Smart Grid and allows LumaSense to have a wide range of products to fit all needs and budgets."

The PowerSens system uses gallium arsenide (GaAs) sensors to measure temperature, and will round out LumaSense's overall fiber optic measurement portfolio used by utilities across the globe. LumaSense's portfolio of fiber optics offerings includes the ThermAsset2 and LumaSmart systems based on Fluoroptic phosphor technology. Fluoroptic technology provides the most reliable method for temperature measurement in critical, large transformers, while GaAs is a cost-effective alternative for smaller projects that don't require as high a level of proven durability.

"PowerSens customers will enjoy several benefits from this acquisition. They will now have access to LumaSense's larger portfolio of temperature-measurement technology, as well as its global support network of experienced application engineers," said Pierre Carrier, President and CEO of Opsens. "For Opsens, this gives us the perfect opportunity to focus on serving the needs of our customers in our main fields with our fiber optic technology."

In the electrical industry, LumaSense's fiber optic temperature (FOT) measurement technology is considered the industry standard for FOT measurement of transformer winding hot spots. FOT uses rugged probes to directly measure winding temperatures for the most-accurate temperature readings, as opposed to conventional methods that have errors from inferring hot spots by trying to simulate or calculate the temperature versus directly measuring it.

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Baltimore Gas and Electric Company to Proceed with Smart Grid Implementation

Baltimore Gas and Electric Company (BGE), a subsidiary of Constellation Energy (NYSE:CEG), announced on August 16 that it will move forward with implementation of smart grid throughout its Central Maryland service territory.

"Following the Maryland Public Service Commission's approval of our project this past Friday, BGE is pleased to move forward with our ambitious smart grid program and deliver the significant transformational benefits of smart grid to each of our 1.2 million customers," said Kenneth W. DeFontes Jr., president and chief executive officer of BGE. "Those benefits include at least $2.5 billion worth of savings for BGE customers over the life of the project, as well as major new enhancements in customer service and reliability. In addition, BGE will be able to take advantage of $200 million that the U.S. Department of Energy awarded BGE for its innovative program, reducing the cost of the project for BGE's residential customers by 80 percent.

"Our decision to move forward also reinforces our continued commitment to helping the state meet its aggressive energy efficiency and conservation objectives under EmPOWER Maryland, and to enhancing the service we provide our customers," said DeFontes.

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BGE's ability to invest the hundreds of millions of dollars in smart grid on behalf of its customers depends on predictability, certainty and fairness in being able to recover those costs. Importantly, in its order, the Maryland Public Service Commission (PSC) found that the public interest is served by a decision to move forward with this initiative. The commission also assured BGE of its right to recover "prudently incurred costs" related to the project, as well as an appropriate return, and that its future review of costs will not be subject to "unfair, post hoc nickling-and-diming." BGE is further encouraged that the PSC accepted BGE's proposal to conduct periodic reviews of project implementation on an ongoing basis, so that BGE and the PSC can more constructively work together to ensure that ongoing project implementation is meeting expectations and enable mid-course corrections, if needed.

"We strongly believe that a gradual, annual phasing-in of both the benefits and costs of smart grid is the best approach for our customers and the company," added DeFontes. "Although the commission chose a different regulatory method than we proposed, we will work with the commission to find ways to better align the benefits and costs of the project while mitigating the potential for a rate spike at the end of deployment."

The PSC also approved BGE's general plan for long-term, customer-focused education and communication surrounding smart grid. Building on experience gained through its highly successful smart grid pilot program and from utilities nationwide, BGE will devote the necessary time and resources to ensure that all of its customers, including limited-income customers and senior citizens, have the information they need prior to each phase of smart grid implementation. BGE is developing the appropriate metrics to ensure the success of its outreach effort.

"We appreciate that the commission now views this initiative as a 'win-win proposition for BGE, its customers and our state," added DeFontes. "We are absolutely confident in our ability to deliver these savings and benefits in a timely and cost-effective fashion."

In addition to the significant energy-management and energy-savings benefits that smart grid affords BGE customers, the company projects the added economic benefit of an estimated 350 direct jobs and more than 1,300 indirect jobs related to implementation of smart grid.

"With our decision to press forward with smart grid, BGE will remain a national leader in delivering innovative and cutting-edge technology to our customers," said DeFontes.

BGE's addition of smart grid adds to the company's growing suite of energy efficiency and conservation programs that it has introduced in recent years. The company has focused on helping its customers take advantage of innovative ways to manage energy use, lower energy costs and reduce environmental impact by offering a number of inventive initiatives that are part of the BGE Smart Energy Savers ProgramSM. These initiatives include residential heating and cooling rebates, PeakRewardsSM programmable thermostat, lighting and appliance rebates on ENERGY STAR® refrigerators and clothes washers, Quick Home Energy Check-up, Home Performance with ENERGY STAR® and Limited Income Energy Efficiency Program.

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Xcel Energy Recommends Clean Air Clean Jobs plan

Company Proposes to Shut Down 900 Megawatts of Coal; Plan Provides Savings of at Least $225 Million

Xcel Energy proposed on August 13 a low-cost option to significantly reduce Colorado coal-fired generation emissions, through a combination of retiring, repowering or retrofitting of several power plants as called for under the recently enacted state Clean Air Clean Jobs Act.

The company's plan has three key components:

- Retires 900 megawatts (MW) of coal generation at its Valmont (186 MW) and Cherokee (717 MW) power plants by the end of 2017 and the end of 2022, respectively;
- Repowers its Cherokee power plant with efficient, natural gas generation of 883 MW. The company also will switch to natural gas generation at the 111 MW Arapahoe unit four; and
- Retrofits about 950 MW of coal-fired generation at the Pawnee (505 MW) and Hayden (446 MW) power plants with modern emission control technology.

Xcel Energy, which supported the Clean Air Clean Jobs legislation, filed its preferred plan with the Colorado Public Utilities Commission (CPUC). The plan responds to a state law passed last spring that required the company to propose reductions in oxides of nitrogen by 70-80 percent by 2017, to meet anticipated federal clean air regulations. The plan would reduce emissions of oxides of nitrogen from the targeted plants by 75 percent at the end 2017, and by 89 percent at the end of 2022.

"Over the next several years, the U.S. Environmental Protection Agency will require the state of Colorado to comply with a series of regulatory mandates unprecedented in the history of the Clean Air Act," said Dick Kelly, Xcel Energy chairman and CEO. "We believe our proposal is the best way to meet new environmental requirements in a manner that preserves reliability and minimizes customer costs."

The total cost of the plan, if approved by the CPUC, would result in new construction investment of approximately $1.3 billion over the next 12 years. The company expects that its proposal will result in savings of approximately $225 million when compared to the traditional approach of retrofitting all of these plants with emissions controls. The savings compared to an all-controls approach would be more than $950 million if there is federal regulation that places a price on carbon dioxide emissions.

In addition, when compared to 2008 levels, the company would reduce sulfur dioxide emissions by 84 percent and mercury emissions by 85 percent for the power plants targeted under the plan by 2023. The plan also allows Xcel Energy to meet Colorado's statewide carbon dioxide reduction goal of 20 percent before the 2020 target.

"Our plan addresses the future of some of our oldest coal-fired power plants at a reasonable cost," said David Eves, president and CEO of Public Service Co. of Colorado, an Xcel Energy company. "Our prices will need to rise over the next several years as we make investments to meet customer demand, and to enhance our transmission system and replace aging distribution infrastructure."

The rate impact of the proposed plan is expected to increase future bills on average by 1 percent annually over the next ten years. Eves noted that this was well below the company's original estimates of 4 percent to 6 percent at the time the legislation was passed.

Xcel Energy studied more than 300 different scenarios in arriving at its preferred plan. The preferred plan is consistent with current and reasonably foreseeable emission reduction requirements, and reduces the company's long-term risk from federal Clean Air Act and climate regulation.

Together with the company's other energy and environmental initiatives, the plan will allow Xcel Energy to maintain a balanced energy mix that includes coal, natural gas, energy efficiency and one of the nation's largest utility portfolios of renewable energy.

Xcel Energy is proposing a new Emission Reduction Adjustment rate to go into effect on Jan. 1, 2011. This adjustment clause will recover the costs incurred under the emissions reduction plan, until rates can be adjusted from time to time to reflect these costs. The details of the plan and the Emissions Reduction Adjustment can be reviewed on the Xcel Energy web site at *www.xcelenergy.com*.

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OSIsoft Announces Its Participation with SAP in the Korean Jeju Smart Grid Test-Bed Project

OSIsoft and SAP Korea Cooperate to Deliver Smart Grid Offering for Smart Grid Test-Bed Project in Korea

OSIsoft, LLC (*www.osisoft.com*), the leader in real-time data infrastructure solutions, announced on August 25 its collaboration with SAP Korea on the KT Jeju smart grid test-bed project. The goal of the Jeju smart grid project is to help companies operate more efficiently with flexibility and adaptability through the establishment of a smart grid in Korea. OSIsoft and SAP will provide solutions to KT for the duration of the Jeju smart grid test-bed project, including OSIsoft Meter Data Unification and Synchronization (MDUS) offerings and SAP® for Utilities solutions. The companies involved in the Jeju smart grid demonstration project will verify the functionality and performance of smart grid solutions from OSIsoft and SAP.

Through this Korean government initiative, Korean businesses are being encouraged to establish sustainable "green" growth of their core businesses through adoption of a smart grid. $191 million USD is to be invested in the Jeju smart grid demonstration project through joint investments from the government and private businesses, with a smart grid infrastructure to be recommended by May 2011. The project will then progress through a two-year period that includes infrastructure construction and an integrated operational phase. The ultimate goal of the project is to develop the Korean smart grid model, while testing and evaluating related technologies under real-life conditions.

"OSIsoft MDUS and SAP for Utilities provide real-time data in milliseconds to manage demand response and coordinate effective power exchange," said Ms. Lee Jisun, manager, Central R&D Lab, KT. "The configuration is simple and the user interface is easy to use."

SAP is establishing a connection to digital meters using the OSIsoft MDUS offering, an SAP-endorsed business solution. Through the connection, the compatibility, functionality and process availability of SAP solutions and OSIsoft MDUS products will be verified.

"OSIsoft has been a leader in providing real-time infrastructure for the smart grid," said C.S. Lui, OSIsoft VP Asia Pacific Sales. "Demand response solutions require a complete picture of what is happening in all aspects of the smart grid in real-time. This is what OSIsoft is providing from generation, transmission and distribution to the smart meter."

OSIsoft MDUS integrates advanced metering infrastructure (AMI) head-end systems with SAP for Utilities solutions. Used in combination with SAP AMI Integration for Utilities software, OSIsoft MDUS makes it feasible for customers to obtain real-time meter data from the smart grid. This allows customers to benefit from capabilities on the smart grid, such as optimized meter to cash, extended customer service, time of use billing and demand-side management.

"SAP has been increasing the efficiency in the energy and utilities industries for the past 30 years through the delivery of innovative enterprise software and platforms," said Won-Joon Hyoung, managing director of SAP Korea. "The SAP AMI Integration for Utilities ensures the seamless process and data integration with OSIsoft MDUS through standardized interfaces. This optimized interoperability is a key prerequisite for the successful implementation of holistic smart grid solutions. More importantly, KT's team was the only consortium that demonstrated a working solution built with SAP solutions that will be demonstrated in front of the delegates from the Group of 20 (G20) later this year."

Circle **20** on Reader Service Card

GUEST EDITORIAL

I think I see the corner… do you?

By Carolyn Kinsman, President, Automated Communication Links, Inc.
Burlington, Ontario Canada

The quest for Smart Grid has revolutionized the way many of us in this industry view utilities and the way they intend to do business in the future. Being known as one of the most risk-averse industries and very slow to change, Smart Grid and the pace at which it is trying to be adopted makes this a very interesting subject to discuss and analyze.

Unlike many other industries that have been revolutionized through new technology, utilities' quest for "Smart" has never been granted the same span of time to properly evolve. Time ensures the stabilization of technology and for the industry to acquire the necessary in-house expertise to grow with that technology. In this way utilities will be assured of a seamless transition of legacy systems into the all-encompassing Smart Grid. Right now the Smart Grid Road Map still needs a lot of brush clearing, blasting and pavement.

The Where & Why of "Smart"

Within the span of a single year – 2005 – the term 'Smart Meter' came into our industry vernacular to articulate function and feature enhancements beyond that which could be acquired through Advanced Metering Infrastructure (AMI). "Smart Grid" followed closely thereafter and sparked frenzy as the industry attempted to reach a consensus on what the term actually meant.

While these terms were still being defined, actual technology to address "Smart" was lagging further behind than what many visionaries had originally predicted. In fact, the vendor community was still establishing the evolutionary path from Advanced Metering Infrastructure to Smart Meters, while utilities were still trying to determine the operational and customer benefits that could be achieved when moving beyond AMI.

Over time the utility industry came to understand that "Smart Anything" meant the requirement to implement better, more comprehensive solutions, able to acquire operation and usage information that could be used throughout the utility operations, including dissemination to the utilities' customers. Simplistically, the complete utility "Smart" vision is a parallel concept to that currently used by manufacturers who have instituted Just-in-Time principles and systems.

Why "Smart" Now?

The rush to embrace "Smart" in the utility industry was spawned from a number of events that took place almost in unison. This included access to cheaper, more robust electronics, utility acceptance of solid state meters and a growing understanding across the vendor community of what was needed to place telecommunications technology in one of the most unfriendly environments there is: Under the meter cover.

These factors were also fueled by other issues including the drive to maximize currently available energy resources; start building renewable energy resources; and recognizing that the current grid was built – and was continuing to be expanded – based on historical estimations rather than what is really occurring at the customer level.

While "Smart" was now defined, no one was ready to actually make it happen. "Smart" had pushed the fledgling fixed-network AMI industry into high gear.

GUEST EDITORIAL - I think I see the corner… do you?

Smart… at Warp Speed

AMR vendors, meter manufacturers and newly formed MDM (Meter Data Management) companies transitioned their strategies from development of the low-cost, dependable "Volkswagen-style" AMR/AMI systems to the more full-featured, data hauling Ferrari.

The rapid acceleration had caught Vendors by surprise and within a year of the term "Smart" the thinly upgraded AMI systems vendors were trying to launch into the Smart market were quickly shelved and replaced with total build-outs of completely new systems.

At the same time, consultants and utilities were busy building new business models, cost justification methods, technology evaluation and deployment methods to address these new "Smart" systems.

With hype travelling faster than reality, the Smart industry experienced some major disconnects regarding what could realistically be delivered to meet regulators' interpretations of "Smart". Utilities found themselves suddenly faced with the challenge of trying to meet these far reaching expectations. In a nutshell, the "Smart" hype was becoming the biggest risk factor for any utility that dared to test the Smart Meter waters.

Vendors Work to "Make it Smart"

All vendors in – or wanting to be in – the Smart Business stepped up investment in R&D. Meter manufacturers launching the first round of fledgling solid state meters believed that these meters should be low cost, providing very basic functionality. In the majority of early Smart Meter deployments that was what all utilities selected to attach to their Smart Meter systems. However, early experience taught meter vendors and utilities alike that while the initial concept of "dumb meter/Smart AMI" originally made good business sense, there was greater value to the overall Smart Grid if enhanced functionality was incorporated into the meter end point.

The bad news was that the litany of enhanced "Smart Meter" functions and features required considerably more communications bandwidth and a much more robust network architecture. Expansion of the bandwidth combined with improved data compression techniques have now been systematically introduced by most AMI Vendors. This expansion of bandwidth is probably the biggest and singularly most challenging requirement Smart Meter Vendors currently face.

Throughout all of this activity with both the Smart Meter and Smart System evolution, MDM software continued to be written, re-written and modified to deliver the necessary processing of Smart Meter data that is needed to deliver the level of data sharing, reporting functions, and of course, accurate billing coordinates required for new variable rate structures. The MDM is becoming a vital cog for the sharing of system data throughout the utility Smart Grid.

Getting Ready to Turn the Corner

While the road to Smart Grid realization has certainly not been pretty, the complete Smart Meter Infrastructure that in most cases forms the foundation for Smart Grid is finally reaching a level of clarity. This is a critical achievement toward ensuring the success of other systems being incorporated into the Smart Grid architecture. We can thank those utilities that were the early adopters, investing serious dollars, manpower and exemplary courage to deploy and work with the vendors to get us to this point.

Recent utility announcements indicate that some of the major projects that have been slowly deployed, evaluated, modified and then re-deployed may be reaching expected and approved levels of an acceptable system service deliverable. Those utilities that could not afford to take a multi-million dollar gamble were probably right to wait.

Going forward, the industry will continue to experience corrections when it comes to "Smart" anything, but we are seeing – dare I say it – a measure of stability? The pioneers of "Smart" will probably struggle a bit longer, but progress is definitely being made and the measure of Smart continues to grow.

Complete industry acceptance will be gained as technology risk continues to diminish with the momentum of successful Smart Meter deployments.

About the Author

Carolyn Kinsman is President of Automated Communication Links Inc., a well known, industry qualified and reputable AMI/Smart Meter Consulting firm. ACL is one of the first AMI consulting firms in North America and is a leader in setting the standard in unbiased, knowledgeable technical and strategic business consulting services solely to utilities.

The 2010 Automation/IT Leadership Series

Malcolm Unsworth
President & Chief Executive Officer

Bruce Angelis
Managing Director, Software Products

Itron

Liberty Lake, Washington USA

"As part of the federal funding included in the American Recovery and Reinvestment Act (ARRA) – often called the Stimulus Bill – the United States government earmarked approximately $3.4 billion to underwrite the installation and deployment of smart technology for the grid. Although most of the awarded funds will go to organizations that invested a great deal in creating a tangible return on investment for projects the money will be funding, the real ROI will be measured by consumer engagement and the acceptance of an inevitable digital grid transformation." – Malcolm Unsworth, President and CEO, Itron Inc. – ***Ed***.

EET&D: There's been a lot of controversy lately about the Stimulus Bill, and in particular, the long-range impact it will ultimately have on our industry. Your comment (above) about consumer engagement, acceptance and eventual adoption of what you refer to as a "digital transformation" raises some interesting questions about the return on these Smart Grid investments. So, let's leave the economics to the economists for now and start off with this concept of a consumer ROI. How is the technology you are providing helping utilities face this digital transformation?

Unsworth: Many of today's utilities are no longer satisfied with deploying meters from one vendor and data collection systems from another. Instead, utilities are searching forvendors who offer complete, end-to-end solutions, customized to their unique needs. That's part of the Smart Grid vision that most in this industry share, and it's one that Itron believes will usher in a more robust, reliable and secure energy future.

EET&D: In your mind, where would you say the concept of Smart Metering intersects with the Smart Grid?

Unsworth: Smart Metering and the Smart Grid are ultimately about an increased level of real-time control of the electricity network, coupled with the ability to influence consumer behavior through access to information – resulting in better management of dwindling energy resources. Smart metering provides the foundation for a smart grid, both by acquiring more detailed information and by providing the communications infrastructure to deliver that data – not only to the utility but the customer as well. And smart meters deliver much more information than traditional meters. This is why utilities are adopting meter data management (MDM) solutions and evaluating vendors to ensure they select the right solution to provide valuable storage, analysis and application of actionable meter data.

EET&D: You mentioned MDM, which has become much more of a high-profile topic lately. And even though MDM systems aren't really anything new, they are finally being brought into the mainstream of AMI discussions and projects. What is the significance of MDM in today's Smart Metering/Smart Grid evolution?

Angelis: MDM solutions have been around for a while, but in a smart grid world they need to operate at a much higher level. With granular reads collected as frequently as every 15 minutes – or even on-demand – utility systems are inundated with more data than ever before. MDM solutions today have to be able to handle the onslaught of data collected by smart meters. These solutions must work at scale with both new and existing systems to meet the needs of the utility and its customers. The more flexible, secure and scalable the solution, the better. Realistic scale testing and benchmarking is necessary to prove the solution. Selecting the right MDM solution to manage these massive volumes of meter data in a secured environment, one that can interface with smart metering and upstream systems, is not only important to achieve a reasonable ROI, but is critical for attaining the transformational changes that will position utilities for success in a rapidly changing business landscape.

EET&D: Along with MDM and the accompanying Advanced Metering Infrastructure (AMI) comes enormous increases in the amount of data that utilities will now be expected to manage and accurately interpret and manipulate. But besides the pure data transport, storage, and management issues, there is also the now constant threat of security breaches – physical and especially cyber. What can utilities reasonably expect in the way of security protection as these data volumes continue to increase exponentially?

Unsworth: Some of the most innovative utilities in America – like Southern California Edison and CenterPoint Energy – are implementing systems that they are confident will allow them to detect, isolate and limit the overall impacts of security threats or intrusions. To fully achieve that objective – for both the utilities and consumers – utilities and their vendors alike must be willing to make a mutual commitment to engage and develop partnerships that build confidence in their ability to successfully address the demands, and potential vulnerabilities, of this dynamic new environment.

EET&D: Speaking of commitments, a lot of utilities are rethinking their dependency on information technology and what that means in terms of carrying out critical functions across the enterprise. Has the role of IT changed with regard to that dependency?

Unsworth: Utility dependency on information technology is fundamental to virtually every aspect of operations, and nowhere is that dependency more evident than in the so called "meter-to-cash" chain – the cash register of the utility enterprise. But because not all utilities are created equal – in size or in structure – reliance upon IT resources can vary greatly. The onset of smart metering has created a larger demand for IT support than ever before.

Utilities require vendors that can deliver systems successfully and at a reasonable cost, regardless of what their IT environment may be; they want systems that will integrate seamlessly. Making good on that commitment requires an ongoing effort to stay focused on core business, but also being able to go beyond traditional metering to embrace the broader adoption of operational, environmental, regulatory and technology requirements that will proactively support Smart Grid goals and objectives.

EET&D: How can utilities be assured that their suppliers not only possess the requisite security knowledge and expertise, but also feel confident that they sufficiently understand the business applications involved to provide adequate protection without causing system functionality to suffer?

Angelis: Itron is a diligent and long-time participant in the utility industry, with over 30 years experience designing solutions that are tailored to the challenges utilities face. This affords us with a unique ability and insight into all aspects of utility operations. We have more experience in automating – and securing – meter data collection networks than anyone in the industry. Each year, millions of dollars worth of utility transaction data flow through our systems worldwide. As a result, utilities feel confident that we can deliver solutions that will keep them, their customers and their data safe and secure. Itron continues to make investments in cyber security across our development lifecycle as the threat landscape evolves.

EET&D: What is it going to take for security to be addressed by the AMI community as a top industry priority?

Unsworth: Itron has consistently taken the position that security for advanced metering and the Smart Grid is a very complex, multi-faceted endeavor – but also one of critical importance. Security needs to be a major industry initiative, and is one that we have made – and will continue to make – a top priority. Metering systems must be designed with security as a core design criterion. Perhaps Bruce can elaborate on that a bit more...

Angelis: Yes. We agree with the Federal Energy Regulatory Commission (FERC) and National Institute of Standards and Technology (NIST) that Smart Grid systems are critical cyber assets that must be secured. Itron has collaborated with Department of Energy (DOE) national labs to develop security testing for advanced metering systems, and we have been working closely and deliberately with our customers and the industry for several years now to specify, design and test our advanced security architecture for smart metering networks.

Unsworth: I might add that we were also key participants in the Utility AMI Security Working Group, a major industry task force created to delineate security threats and develop a wide range of defense guidelines for the industry. Itron continues to participate in and lead industry-wide efforts to create standards for networks that are not only open but also secure.

EET&D: Security is – as one might expect – quite a diverse and complex subject, but could you perhaps give our readers a few examples of the kinds of things that these measures are designed to address, at least categorically?

Angelis: Sure. Without getting too technical, there are several major elements that must be addressed, carefully and holistically. A few of the most important ones are: Architecture, Standardization and Communications Integrity.

First of all, there's Architecture. We've built an extensible architecture that allows us to partner with other industry leaders to offer a complete and secure solution for smart metering. CenterPoint Energy was the first utility in the nation to roll out this advanced security architecture with their AMI system in 2009, and we established the Itron Security Center to track, address, and immediately respond to any security issues that may arise when that system was installed.

Secondly, we have Standardization. Technologies and standards exist today to support secure deployment of AMI. But because these technologies and standards must evolve and improve over time, AMI systems must be flexible enough to accommodate efficient upgrades over the network. As with any aging system, there are already many places in the existing energy infrastructure that could be exploited by cyber or terrorist attack. But we believe that the design diligence and other mitigation measures incorporated into current Smart Grid deployments will, in fact, not only increase the operating efficiency of our electric grid, but also provide significantly more security than exists in today's operating models.

Communications Integrity is another huge area of concern. In 2009, we upgraded our software with new security measures designed to protect our smart metering solution as a critical cyber asset. These enhancements were made primarily because of the two-way communication nature of the system, and the ability to connect and reconnect service with every device. This design included or improved upon previous features, such as strong authentication and encryption for all over-the-air messages, ensuring that everything received by the meter is confidential, complete and authenticated by the system.

EET&D: Isn't privacy another big issue that must be confronted?

Unsworth: Yes, of course. One of the biggest concerns regarding privacy is keeping customer data out of the wrong hands and from those who would use the data for illegal purposes. First, no personally identifiable information (PII) is stored or transmitted in our smart meter system. As an added level of privacy, we employ asymmetric cryptography to protect the privacy of metering data as well. Finally, two-way communications allow the utility to be immediately notified of any tampering at the meter, in near real-time. And, as mentioned earlier in our discussion, we have completed a security assessment with DOE's Idaho National Labs, which is repeated after every major software release as standard practice.

EET&D: These days it seems like the pace of technology is faster than ever before – probably because it really is. And utilities have a longstanding reputation of being not only risk averse, but many would argue, change averse.

And utility customers are probably even worse when it comes to something as well established and as basic a commodity as electricity. So how does one go about empowering utilities to be agents of change – especially as regards meter implementation and customer adoption?

Unsworth: It starts with having a complete solution, rather than just parts of the puzzle. Through our long history of acquisitions, organic growth and extensive R&D investments, Itron is fortunate to have very complete and robust end-to-end solutions. Our MDM system allows us to work with both new and existing technologies to achieve economies of scale and help provide the best possible customer service. It interfaces easily with multiple meter data collection systems – across communications platforms – and scales to up to 10 million meters.

EET&D: When you talk about scalability we usually think size in number of meters, but what about adaptability to various sets of utility requirements and operating environments?

Unsworth: In order to deliver successful solutions, vendors need to design flexible systems that allow them to contribute at different points across a utility's operations. Experience is a key factor when delivering an optimized solution for each utility's specific needs. This is easier said than done, and requires a portfolio that offers not just advanced measurement, data collection and meter data management solutions, but also analysis and application tools to complete the equation. Load forecasting, web presentment tools, load management and revenue protection services can all leverage smart meter data.

EET&D: Going back to the ROI question, how important is it for that traditional ROI – the one measured in dollars – to be a part of the solution?

Unsworth: Naturally, it's important to achieve a reasonable ROI, but in our opinion, it's perhaps even more critical to achieve the transformational changes that can position utilities for success in a rapidly changing business landscape. And considering the declining condition of our present energy infrastructure and our increasing dependence on fossil fuels, we cannot wait any longer to begin utilizing technology that will reduce energy consumption, peak energy demand, and carbon emissions.

LightsOn

Increasing Customer Awareness of the Benefits of Smart Grid in Oklahoma

By:
Ken Grant, Managing Director Smart Grid Program, OG&E, Oklahoma City, Oklahoma USA

Matthew Smith, Senior Director, Product Marketing Silver Spring Networks, Redwood City, California USA

The ultimate success of a Smart Grid in achieving greater energy efficiency relies on the strength of the partnership between a utility, its customers and its regulators. Although surveys show that the public has positive feelings about Smart Grid technology and is eager to use it, successful implementation requires a comprehensive communications strategy. Without strong customer education and support, the benefits of smart meters and other smart-energy tools, such as energy management websites, in-home displays (IHDs) and programmable communicating thermostats (PCTs) will not be realized. Recognizing this, Oklahoma Gas & Electric (OG&E) designed a study and communications plan to learn more about how customers could and would use new Smart Grid tools.

A Study is Born

In March 2010, the utility began Smart Study TOGETHER™, an effort funded by part of a $130 million grant from the U.S. Department of Energy and endorsed by the Oklahoma Corporation Commission in July 2010 when it approved a $240 million rider on customers' bills for system-wide smart grid deployment. Some 3,000 volunteer households and businesses in Norman, Okla., were recruited to join in the study, which ran from June 2010 through September 2010 and will run again during the same four months in 2011.

Residential participants are assigned one of two dynamic price plans and one, two or all three of the in-home tools enabling them to monitor their energy use – the PCT, IHD and energy management website. Business participants have their choice of price plans and technology. The goal of the study is to determine, with statistical validity, if OG&E in partnership with its customers can reduce system-wide peak demand by approximately 160mW.

Two in-home devices used as part of OG&E's Smart Study TOGETHERTM in Norman, Okla.

Ultimately, by seeing how customers react to having more information about the cost and their use of energy, OG&E will be able to learn what combination of pricing plans, technology and customer messaging will result in the most significant behavioral changes. Smart Study TOGETHER aims to provide a template for OG&E – as well as the DOE and other utilities – to consult when planning future applications for Smart Grid technologies and pricing plans.

Focus on the Customer

From the start, OG&E's focus has been on the customer. The company continues to proactively communicate with customers to clearly describe the benefits of the comprehensive deployment of Smart Grid using paid mass media, letters mailed to homes and businesses, door hangers and fliers distributed by field personnel, and information available online. The same tactics along with e-mail and face-to-face "sales calls" were used to recruit study participants last spring.

To complement this effort, meter techs, field service representatives and call-center employees receive special training to help them answer customer questions. OG&E representatives attend community meetings to explain the benefits of the program and also meet with local leaders to gain their support and understanding of the benefits to the community. OG&E continues to assure customers that while the new Smart Grid technology can empower them to control their energy use and lower their bills; it does not provide the utility direct control of customers' devices. Customers control and predetermine their price and comfort sensitivity. To monitor awareness of the Smart Grid and brand reputation, the company conducts quarterly telephone surveys.

Finally, OG&E ensures that its customers and employees understand the importance of participation in the study. Several customers have provided testimonials about why they want to be part of the study. (See sidebar featuring Steve Kaplan, owner of Native Roots Market in Norman.)

Building on Success

Smart Study TOGETHER builds on the positive results of a smaller, three-month study that OG&E conducted in the summer of 2008 with 25 residential customers in Oklahoma City. At the conclusion of that pilot, a survey of the participants found that 100 percent were more aware of their energy consumption and pricing. This knowledge enabled the participants to cut their energy use during peak hours of 2 p.m. to 7 p.m., with the households saving an average of 10 percent to 13 percent per month on their energy bills during the summer months.

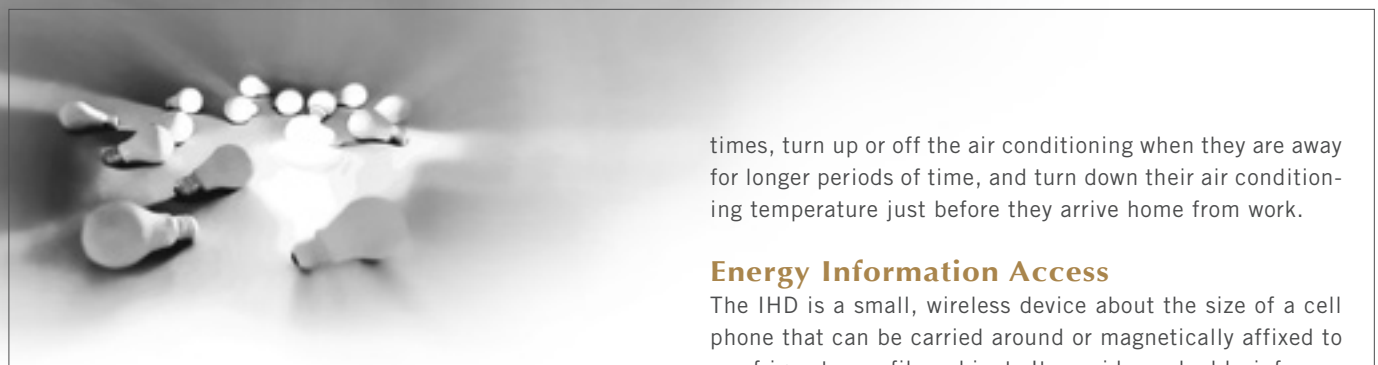
OG&E also realized operational savings from smart meters and the rest of the advanced metering infrastructure installed in the same area to serve 6,600 customers. This data helped drive OG&E's decision to pursue a comprehensive integrated Smart Grid deployment – including advances in demand response, wind energy and regional transmission – to reduce peak demand enough to avoid building new fossil fuel capacity before 2020.

Pricing Plans

For the study, OG&E is testing two innovative pricing plans to determine which is best suited to which customer groups. One is a standard Time-of-Use (TOU) plan, and the other option is Variable Peak Pricing (VPP). Both plans include a Critical Price (CP) overcall component. Under TOU, customers pay a higher price for energy used during the peak demand period of 2 p.m. to 7 p.m. weekdays. VPP offers four peak period prices.

The peak price for a day is set by 5 p.m. the evening before. These prices are communicated to participants in the study through one or all of the methods of their choosing, including automated phone calls, e-mail, and cellular text messages. The day-ahead prices also are posted each day on the corporate website *www.oge.com/price* by 5 p.m. and in the future will be available via an Apple iPhone application from OG&E. The peak prices also are communicated via sophisticated back-end software to study participants via their IHDs, PCTs and the *myOGEpower.com* website.

A PCT displays the peak price for a customer in OG&E's Smart Study TOGETHERTM Program



These smart tools also display a highly accurate estimate per kWh, including taxes and other charges, so study participants receive the most actionable information possible to make choices about their energy consumption each day. Similarly calculated month-to-date cost estimates are also available on the IHDs and web portal.

Smart Energy Platform

The Smart Energy Platform (supplied by OG&E partner Silver Spring Networks) enables the demand response capabilities. This Smart Energy Platform includes an AMI network, the communications module in OG&E's Smart Meters, back-end demand management software, the secure energy management website, and in-home devices such as PCTs and IHDs. The tools provide customer-friendly views and management.

Diagram depicts 2-way communication between the Home Area Network (HAN) and the Wide Area Network (WAN). Electricity usage data is collected at the meter and then distributed to in-home devices within the HAN. At the same time the data is sent out via access points to OG&E's back office via the WAN. That information is then routed back to the consumer via the internet and viewed using *myOGEpower.com*.

The thermostats, for example, feature a simple interface for efficiently using air conditioning during off-peak hours, critical since 35 percent of power in Oklahoma is used for central air. The thermostats offer customers five separate settings that allow them to easily balance comfort and economy in their homes or businesses, taking into account time of day and kWh price. For example, participants can choose programs that "pre-cool" their homes before peak demand times, turn up or off the air conditioning when they are away for longer periods of time, and turn down their air conditioning temperature just before they arrive home from work.

Energy Information Access

The IHD is a small, wireless device about the size of a cell phone that can be carried around or magnetically affixed to a refrigerator or file cabinet. It provides valuable information on energy pricing and use. Using its six buttons, users can easily scroll through the device's screens to find data on current electricity use, in dollars, cents and kilowatt hours; daily, weekly and monthly usage; and the current price of energy. Even more energy use and cost information is available when study participants log-on to their own personalized websites at *myOGEpower.com*.

On the web, customers find their energy consumption and cost information, as well as being able to compare their usage to that of others in their community and see details about their carbon footprint. Each customer's energy consumption is presented in detailed graphs, showing usage by time and price. This data allows customers to see how their energy prices fluctuate depending on the weather and time of day, allowing them to make choices based on more information.

Throughout the study, OG&E is checking back with participants to gather intelligence about how they receive the most value from Smart Grid applications and about how to best engage customers in programs to capitalize on the promise of Smart Grid technology.

OG&E's *myOGEpower.com* website enables customers participating in the study to view electricity pricing and their consumption information in near real-time.

A Customer's Experience

As the owner of the Native Roots Market in Norman, Oklahoma, Steve Kaplan specializes in offering his customers organic, locally grown and high-quality fresh foods. Since opening the store three years ago, Kaplan also has tried to conserve as much energy as possible, taking steps such as installing energy-efficient lighting, motion-activated lights in his stock-room, and ceiling fans to reduce the energy draw for air conditioning. So Kaplan was intrigued when he saw an insert with his regular OG&E bill promoting a chance for businesses to join a study seeking ways to cut energy use. He signed up online, and his store was soon fitted with new programmable communicating thermostats, as well as a wirelessly connected smart meter. Kaplan also gained access to a personalized website detailing his store's energy use and daily e-mails from OG&E relaying energy prices for the next day's peak period of 2 p.m. to 7 p.m.

Armed with this information, Kaplan began to make some small adjustments that have resulted in significantly curtailing his store's energy consumption. He stocks a refrigerator of grab-and-go drinks early in the morning, so that the doors aren't opened as frequently during peak-hour energy prices. He also pre-chills the store to 73 degrees in the morning and then cuts off the air conditioning for an hour or two when the 2 p.m. peak price period begins. In addition, Kaplan regularly checks the OG&E website to review his store's energy consumption. The changes are modest, but the results are astounding. "When our first bill came, we were shocked at the savings that they reported. We just couldn't believe them," he says. "The bill would normally have been approximately $1200, and it was $700."

That $500 in savings sold Kaplan on the new technology. "Now that we have the in-home device and the thermostats, we look at it every day to see what our usage is and what we can possibly do to conserve during the peak period," he says. "I expected that we would save something, but I didn't think there were that many things we could do at our store to affect the bill because of the nature of our operation. So we're just delighted with what's happened."

PROGRAM FACTS: Smart Study TOGETHER™

Launched: March 2010

Study Size: 3,000 volunteer households and businesses in Norman, Oklahoma

Timeline: June 2010 through September 2010; will run again during the same four months in 2011

About the Study: Residential participants assigned one of two dynamic price plans and one, two or all three of the PCT, IHD and web tool to monitor energy use; Business participants have their choice of price plans and technology.

Goal: To determine if, through a statistically valid trial, OG&E in partnership with its customers can reduce system wide peak demand by approximately 160mW

Funding: Part of $130 million grant from the U.S. Department of Energy

Technology Partner: Silver Spring Networks

About the Authors

Ken Grant is Managing Director of Positive Energy® Smart Grid Programs at OG&E. His education includes a BS from the University of Oklahoma and an MBA from the University of Central Oklahoma. Ken has worked for OGE for 18 years. In his current role he directs a team of professionals tasked with understanding all aspects of smart grid technologies and the potential implications on OG&E and its customers. The team completed deployment of the first Positive Energy® Community in Norman, Oklahoma in May 2010, and is continuing deployment across the remainder of OG&E's service territory.

Matthew Smith heads up Silver Spring's product marketing team for the energy efficiency, demand response and electric vehicle charging solutions. Matthew has over 20 years of startup business experience in the energy management, home computer, consumer electronics, and Internet industries. Prior to Silver Spring, Matthew was in charge of marketing and sales for Greenbox Technology, an early leader in customer facing, smart grid applications. Matthew holds an MBA in Sustainable Management from the Presidio School of Management and a B.S. in Computer Science from the University of Pittsburgh.

A "Customers-First" Smart Grid?

Bluebonnet Seeks to Empower Members with Daily Energy Usage Information

By Matt Bentke, Chief Operating Officer, Bluebonnet Electric Cooperative
Bastrop, Texas USA

There's an interesting Smart Grid experiment underway deep in the heart of Texas. Bluebonnet Electric Cooperative, a member-owned utility with over 80,0000 meters across hundreds of miles of Central Texas, has teamed up with Smart Grid software company eMeter and Siemens Energy Inc. to provide its members with the information they need to better manage their power consumption and electric bills.

What's different about Bluebonnet's Sustainable Grid Project is the way in which we're engaging our members in the Smart Grid implementation process long *before* installing any new smart meters in their homes. We fully intend to upgrade our existing meters with two-way AMI infrastructure, but before we do, it is imperative that we engage and educate our members with the same energy-saving tools that many smart meter deployments have promised they'll deliver. The fact that we, along with eMeter and Siemens, have delivered this level of connectivity without installing any smart meters brings into focus a key question — should the meter or the customer come first?

Smart Meters Everywhere

Smart meters are being rolled out in the millions across the United States and are a critical component of most electrical utilities' Smart Grid plans. Investor-owned, municipally owned and cooperative utilities alike are assessing the value of digital meters to their current business model from simply automated reading to more fully integrated systems. Yet not as many utilities are looking into the most fundamental challenge of shifting control from their internal systems to the customer's home. While consumers can gain insight into almost all other aspects of their daily lives, from banking to cell phone minutes, their electrical bills are often an expensive reaction to shifting weather and seasonal fuel prices.

If empowered with basic information on when and what appliances and various electrical users in their homes actually cost each day or each month, the consumer joins their utility company as a partner to modernize the grid. Armed with better feedback about their usage, consumers will continue to enhance their responses by shifting consumption to off-peak hours so that new rate pricing models enabled by smart meters can effectively cut costs.

But Smart Meters Alone Won't Do It!

In fact, the American Council for an Energy Efficient Economy concluded in a June 2010 report that smart meters on their own are not enough to cut customer costs or save energy. Instead, it will take a host of new tools and services to deliver on smart meters' promise to save power and money. That promise is significant but absolutely attainable — ACEEE concluded smart meters could cut customer costs by 12 percent and save the country some $35 billion over the next 20 years, but only if utilities provide their customers with a range of tools to make smart decisions about their energy usage.

Photos courtesy of Sarah Beal, Staff Photographer, Bluebonnet Electric Cooperative.

The Net Energy Market, our member web portal, was launched in June 2010. As of this summer, we are now giving thousands of Bluebonnet members insight into their daily electricity usage, their corresponding carbon footprint, and the power to set monthly energy usage budgets by sending online or text message alerts when those budgets are exceeded. It's also giving members updates on our Smart Grid deployment plans to come, including time-of-use pricing and ways to compare household energy usage to that of one's neighbors.

Net Energy Market Web Portal Gives Members Daily Energy Usage Insights

By connecting with our members before deploying smart meters, Bluebonnet also seeks to avoid some of the customer engagement problems that have plagued other smart meter rollouts. In the past year, several utilities have faced lawsuits alleging that newly deployed smart meters have overcharged customers. Most consumers assume that these bill discrepancies were caused by incorrect readings by the meters; however recent tests have shown that smart meters are 99.9 percent accurate.

These issues are proof positive that while specific technological problems can be easily dealt with, it's much more difficult to change negative public perception. The Net Energy Market platform is meant not only to explain the benefits of smart meters to our members, but also to ensure they are well acquainted with watching their energy use and communicating with us before we begin installing smart meters in their homes.

Information Access is Key

Opening up energy usage information to our members has been an extensive but pivotal step in Bluebonnet's long journey towards a transformed electrical infrastructure. Of our 80,000 meters, more than 80 percent are residential and spread out over a wide, largely rural geographic area (averaging seven meters per mile over more than 11,000 miles per line), presenting a wealth of challenges in ensuring reliable, consistent service.

Moreover, we can anticipate large increases in electrical demand and consumption due simply to population growth in the next ten years. Because we've invested in the right technologies, implemented the proper programs and tools, we are confident that we'll be able to scale up as needed and support the growing demands of our members.

In 2004, Bluebonnet embarked on an aggressive strategy to develop a new infrastructure to position us for substantial future growth. Our Board of Directors challenged us to purchase a new business operating system (SAP), develop a digital microwave network, invest in new equipment, install a Geographic Information System (GIS), and place automatic meter reading technology (AMR) throughout our service area.

What is Past is Prologue

During the next four years, we accomplished these goals while meeting the board's requirement for maintaining competitive rates and a sound equity ratio. By 2008, we had installed SAP, AMR, GIS, a digital microwave system, an outage management system (OMS), and also placed an automatic vehicle locator (AVL) system and a laptop computer in each of our trucks allowing field employees to efficiently utilize the new technology.

It's important to remember that we are not rejecting smart meters as part of our future plans, as demonstrated by our previous installation of earlier generation AMR digital meters throughout our service area. Due to our early commitment to transforming the grid infrastructure, those Aclara meters communicate over power lines and deliver reliable reads and outage detection, an enormous realization of efficiency even before we put the first AMI meter in the field, and were managed on software from the same company. Now, data from those meters is managed through our new Siemens/eMeter platform — a move that allows us to test the platform's capabilities on our existing infrastructure, while ensuring its ability to accommodate whatever smart meters we may install in the future.

Transitioning for the Future

This fall, we will begin deployment of a demand response pilot project in our territory, as well as a host of distribution automation plans, all of which we hope to manage on the Siemens/eMeter platform. Utilizing an integrated approach to the Smart Grid will help us avoid the unexpected costs of integrating disparate systems after installation. The pilot will assess the effectiveness of managing load based on profiles that participating members set up through the Net Energy Market for their thermostat, hot water heater, etc.

In preparation for this pilot, we have increased the level of consistent messaging delivered on the Sustainable Grid Project through a variety of channels, including bill inserts, our website, social media and local news outlets. Outlining the three central themes of our Project – saving money for members, improving service levels to members, and improved environmental impact – we intend to address any community concerns over the course of the year-long pilot and as we move further forward in our transition to AMI digital meters.

As our Chief Executive Officer Mark Rose has continually said, if we are to envision an electric delivery system worthy of the 21st century and beyond, then we must think past the next round of traditional generation sources or even the more popular renewable energy programs. It is not as simple as 45 more nuclear plants, cleaner coal, solar paint or 40,000 megawatts of wind.

We must fundamentally transform the partnership between the utility and the consumer by empowering the latter with as much information and as much access to the grid as is held by the distributor or the wholesale generator. From our member service representatives to the linemen and staking crews, consumer empowerment is a shared vision and philosophy. For us, the answer is simple: putting our members first is the smartest way to ensure our Smart Grid success. ■

About the Author

Matt Bentke is Bluebonnet's Chief Operating Officer. He is responsible for oversight of all daily operations and manages 10 business units: Field Operations, Engineering, Member Services, Administration, Purchasing, Operations Technology, Government Affairs and Economic Development, Public Affairs and Communications, Corporate Initiatives, and Safety. He leads Bluebonnet's senior leadership team. Prior to becoming Chief Operating Officer in 2008, Matt served as Manager of System of Operations and Manager of Finance and has been with Bluebonnet since 2000. Matt serves on the Lower Colorado River Authority's generation advisory board. He graduated from Texas A&M in 1995, with a BBA in Business Management.

Engaging your Consumers for Smart Grid Success

By Victor Jimenez, Strategic Planning and Architecture, Pacific Gas & Electric, with Kael Kelly, Senior Director, Varolii

The United States government continues to ramp up its investment in the modernization of our country's energy grid system. The recent federal stimulus package included a $3.4 billion grant to incent private companies, utilities and manufacturers to develop and install technologies that will transform today's grid into a smarter, stronger and more reliable electrical system. In turn, a smarter system will empower consumers to monitor their consumption, reduce their demand and ultimately conserve precious energy resources.

As utilities consider how best to leverage various Smart Grid technologies ranging from improved grid infrastructure to in-home smart meters, they can't overlook an essential component of a successful transition that has nothing to do with the technology: ensuring consumer support. Making consumers better aware of Smart Grid is the first step. And then proactively educating them about the positive impact that a Smart Grid system will have on reducing their energy consumption and how it will place more control in their hands are the keys to getting consumers on board with the new program.

For the most part, consumers like the underlying idea of a Smart Grid. According to a recent Harris Interactive research poll, a majority of U.S. adults (57 percent) are aware of how much electricity they are currently consuming, and an even greater number (67 percent) say they would reduce their energy usage if they had visibility into it. A fundamental promise of smart meters is to provide continuous consumption feedback to consumers. This is critical because someday, as a standard practice, meter rates could be tied to the cost to produce electricity, which rises during peak hours. If this type of pricing replaces the current flat rate pricing, 75 percent of Americans would "want to be able to see and control how much electricity" they are using, according to the survey.

Just as people like to see the calls and text messages they're being charged for on their phone bill, knowing how much electricity they're consuming gives customers control over their use and how much money they're spending. According to Oracle's 2009 online survey of U.S. energy consumers, an estimated 95 percent of Americans say they are interested in receiving information about their energy consumption from their utility provider. However, not all consumers realize they can (or soon will have) this kind of real-time visibility into their consumption rates – let alone that their utility providers are even making major technological investments to overlay the conventional energy system.

According to the Harris Interactive research poll, 68 percent of Americans haven't heard of Smart Grid and 63 percent haven't heard of smart meters. This low level of awareness implies that consumers may not know the long-term benefits of a Smart Grid system and will be less willing to initially pay higher premiums associated with the technology upgrades.

Consumer Awareness and Education Starts with Providing Reasons for a Smart Grid

Our nation's electric infrastructure is rapidly running up against its own limitations, according to the U.S. Department of Energy. The risks associated with relying on an often-overtaxed grid grow more complex every day. Emerging challenges, such as security and the effects of climate change, make system transformation necessary. However, not all consumers are aware of the reasons why our country needs a new energy system.

The first step utilities need to consider before implementing a Smart Grid program is to educate consumers on why making the investment today is critical for seeing benefits tomorrow. For example, one way that utilities can convey this message is by posting the following reasons for a new energy system on their websites or as a bill insert:

1. **Bloated Energy Demand** - Since the early 1980s, peak demand for electricity exceed transmission growth by nearly 25 percent every year due to a growing population, bigger homes and more advanced appliances. And, during peak consumption hours, power and distribution centers face a virtual traffic jam of consumers using massive amounts of energy at the same exact time.

2. **Aging Infrastructure** – The power grid is nearly a century old; it is becoming increasingly frail due to rising energy demands and limited visibility into grid operations. As expressed by the Office of Electricity Delivery and Energy Reliability, "...the U.S. electrical grid, once the envy of the world, is no longer world class [and] remains bogged down with mid-20th century technology."

3. **Minimal Funding** – Even with a clear need for upgrading the grid, the portion of utilities' revenues that are spent on research and development is the lowest of all industries (less than 2 percent). In order to make any change at all, all parties involved in our nation's energy consumption, including the government and consumers, need to make initial investments to see any progress.

4. **Pricing Spikes** – As states remove rate caps and the cost of electricity multiplies, consumers are seeing their power bills increase with little information on how to combat rising costs. With a Smart Grid system, consumers will be able to see real-time usage and pricing information, giving them the opportunity to immediately alter their rate of consumption and ultimately, save money.

5. **Exacerbated Outages** – More outages are occurring due to the slow response times of mechanical switches, lack of automated analytics and lack of visibility into the existing grid infrastructure. In fact, there have been five massive blackouts in the past 40 years, three of which occurred in the past nine years. An upgraded grid will improve energy efficiency and reduce outage occurrences that can cost businesses millions of dollars in recovery and lost revenue today.

6. **Environmental Awareness** – If the current grid were just 5 percent more efficient, the energy savings would equate to permanently eliminating the fuel and greenhouse gas emissions from 53 million cars. The new grid system will not only save energy, but it will incorporate technology applications that allow easier integration and higher penetration of renewable energies.

Smart Grid Success Depends on Consumer Support

The key to convincing consumers that Smart Grid is a worthwhile investment is to proactively educate them about what changes to expect and the specific benefits they will see on a daily basis. Getting program information in front of them before making major service and pricing changes will ultimately impact the success of the program. The benefits to consumers include:

- More accurate and timely billing;
- Better energy consumption information to understand and manage their bills;
- Faster outage notifications and restoration times;
- More energy efficiency and demand response programs to help lower costs;
- Reduced inconvenience associated with meter reads and service turn-on and shut-off.

Lessons Learned About Smart Grid Education Programs

There have been several cases where North American utilities did not proactively communicate with their customers about fundamental elements of Smart Grid programs, such as the installation of smart meters, and suffered consumer backlash as a result. By not informing their customers, these utilities suffered a spike in complaints to the Public Utilities Commission because electric bills soared right after the meters were installed. The lack of consumer education and ongoing communication can make for a turbulent start to these Smart Grid program roll-outs.

And, the government is recognizing the importance of upfront communications. For example, Baltimore Gas & Electric's (BG&E) proposal to install 1.2 million smart meters was initially rejected by Maryland's Public Service Commission, in part, because the BG&E proposal contained no detailed customer education plan or messaging to drive the new behavioral changes required to make the transition. The commission's decision also noted that any Time-of-Use pricing scheme would need an even savvier education plan for customers to comply with the program.

In contrast, a Canadian utility took a more proactive approach by communicating with its customers prior to smart meter installations, letting them know exactly what to expect and how they could save money on Time-of-Use rates.

Several months after the meters were installed, and after several reminders, they placed all residential customers on a voluntary Time-of-Use rate program, and allowed customers to opt out if they chose to do so. As customers saw concrete, daily benefits from their smart meters, they reacted positively towards the program.

Usage Notifications Eliminate the Surprise Factor

In the past, the utilities industry has relied on direct mail and door-to-door task forces to spread awareness about changes to services or new program offerings. Typically, utilities experience a low response rate to these basic communication initiatives. It is clear that if utilities want to spread the word about their Smart Grid programs and ensure customer enrollment, a smarter communications strategy will be required.

Today, more progressive utilities are turning to automated and interactive communications via multiple channels, such as voice, text messages and email, to send customers information about upcoming changes and the benefits associated with new programs. Several are even using automated communications to send customers ongoing usage alerts, giving them more frequent information about their energy consumption to help them think about scaling back.

Previously, this type of information was not available with older meters that were read on a monthly basis. Also, utilities are starting to use automated communications for their demand side management programs to provide their customers with timely information about curtailment events or time-sensitive programs.

Pacific Gas & Electric (PG&E), a regional utility serving 15 million people, recently implemented a Smart Grid automated communications program. The utility sends residential customers who have electric smart meters an automated alert when their usage has either crossed or is approaching the threshold for a higher payment tier. The early results are encouraging as most customers were previously not aware of their usage tiers, and the information was not available with legacy meters. PG&E expects most customers will respond to the increased awareness of their usage habits by reducing their energy consumption and/or exploring alternative rates or programs.

Automated communications have helped PG&E provide even better service to customers at a fraction of the cost of direct mail and door-to-door task forces. Additionally, the automated communications deflect inbound calls into the utility's contact center by anticipating questions customers may have and proactively sending them information to address their concerns. In turn, the utility's contact center agents can focus on the customers who have more serious service issues and require immediate assistance.

Early and Frequent Communication Ensures Program Success

Smart Grid programs are rapidly picking up steam. In fact, more than 8 million smart meters have already been installed throughout the United States, and an additional 50 million are expected to be in use by 2015 (according to a list of publicly announced projects kept by The Edison Foundation). While this increase suggests a fast and inevitable transition to a national Smart Grid, consumers must be on board with it. However, experts point out that consumer cost-sensitivity is one of the biggest challenges to overcome. While many agree about the benefits of tomorrow's utility grid, in the present economy, consumers are still reluctant to pay for anything they don't deem a vital necessity.

It's essential for utilities to communicate early and often with their customers about Smart Grid programs before and during implementation. Consumers must be fully aware of the changes to expect and the immediate and long-term benefits they will experience. Proactive education and transparent communication will allow adoption of the new program to be far more successful and help utilities drive higher customer satisfaction levels.

About the Authors

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You've Got the Meter Data – Now What?

By Tony Giroti, CEO, BRIDGE Energy Group, Inc.
Marlborough, Massachusetts USA

As Smart Grid continues to transform the entire power industry, some of the initial focus around Smart Grid and Demand Response (SG & DR) has been in the areas of deploying Smart Meters and reading these through Automated Meter Reading (AMR) and Advanced Metering Infrastructure (AMI). As Meter Data Management products and applications are being employed to collect the data for various Smart Grid initiatives such as advanced billing, real-time pricing and managing grid reliability - the enormous increase in data volume has prompted a broader look at not only how to access data, but how to subsequently manage, analyze and utilize the data. The missing link from accessible to actionable comes down to a lack of strategic IT infrastructure.

Unfortunately, the power industry has traditionally been a laggard in adopting Information Technology (IT), either because of a lack of funding or the absence of business drivers mandating the development of a strategic IT architecture. As a result, the motivation for creating a strategic IT architecture, also known as an Enterprise Architecture (EA), has not been compelling to date.

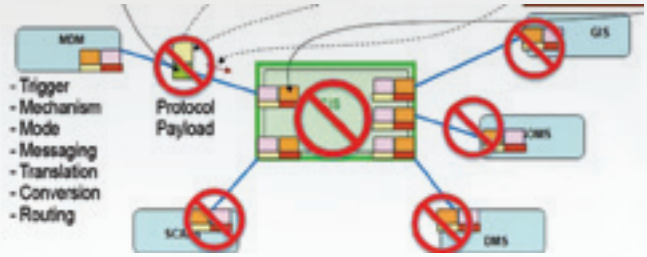
IT as an afterthought – especially around application integration – continues to be the norm for a majority of Smart Grid pilots across North America. Most utilities focused exclusively on deploying Smart Meters, communication infrastructure and Meter Data Management (MDM) products in their pilot phases have not included developing a strategic integration architecture that ties MDM data with other enterprise applications such as Outage Management System (OMS), Customer Information System (CIS), Geographical Information System (GIS), Distribution Management System (DMS), and Supervisory Control and Data Acquisition (SCADA).

This is primarily due to the fact that up until now, the industry has had minimal real-time integration demands. In fact, most integration needs have historically been met tactically through a one-off and project-based approach. IT has never had the motivation, the business drivers or the budget to develop a strategic architecture or develop a standardized approach to integration. Application and data integration requirements have been met through a tactical approach based upon any available technology or middleware offered by the application or system vendor.

As a result, quick *point-to-point* interfaces that are non-standard and custom-coded have evolved as the norm, simply to achieve short-term objectives. Compounding the issue, many of these interfaces are batch rather than real-time, with database links and proprietary code that is customized by writing more code within the application.

The Current State of Integration

How does P2P custom code become problematic as MDM products pave the way in many Smart Grid pilots? Take the example of the popular approach of connecting MDM with CIS in a point-to-point manner. That may work for low volume and low transaction pilots but will not scale to production quality volumes and bi-directional communication models as needed. Moreover, if the CIS is ever to be replaced, the MDM integration with CIS will require redesign and rework. This highlights the case that a point-to-point integration approach is not scalable, precludes future upgrades, and increases risk to the organization, as any change to the application would have a "ripple effect" on other downstream applications.



Example- Connecting MDM with CIS – Everything must be hand coded. If you replace or add an Application, the entire Ecosystem will be affected.

Moreover, the integration gap continues to widen over time as custom code is written for each P2P interface. The viral impact of the point-to-point architecture continues to reduce the overall integration capability, making each change riskier than the one prior. Data continues to be locked in silos and sharing becomes a significant challenge over time. This growth over time has resulted in what is referred to as "Accidental Architecture" where custom code is required to handle all aspects of communications between applications. Thus, the current tactical approach that served companies well in the past will not scale to support the larger vision of Smart Grid and Demand Response.

The back office has not been a major area of focus, which has created a gap in strategic IT architecture.

Smart Grid Architecture, the P2P Antidote

As an alternative to P2P architecture, there is a more strategic "Smart Grid Architecture" that specifically addresses integration and interoperability challenges. Smart Grid and Demand Response initiatives will require real-time integration of applications and systems to enable real-time communication and timely sharing of data to make informed decisions. The tools and infrastructure that are required to realize the Smart Grid architecture and vision will vary from project to project and may include: SOA toolset, development tools, configuration management tools, a source control tool, infrastructure for development, testing and production, etc.

Real-time Enterprise Architecture

One of the key aspects of the Smart Grid Architecture is to provision real-time decision making, which is possible only if data can be harnessed as it is generated (without much latency) and is applied towards a specific objective that requires data as it happens. Such capabilities are possible only with a Real-Time Enterprise Integration Architecture (RTEIA), where immediacy of data is critical and data flows seamlessly between applications and systems (with appropriate governance and security controls).

This real-time or "active" data has significantly more value than the static and old data as it can be harnessed to make just-in-time decisions, such as automated outage detection through the last-gasp meter data for proactive customer service and proactive self healing of the grid; detection of current load and critical peak conditions to initiate automated load curtailment programs to curtail power at participating C&I customer premises, or to perform air conditioning load curtailment at participating retail households. Non real-time integration requirements via batch-data or "passive" flow of data can be leveraged appropriately for non real-time decision-making. Both active and passive data has value and can be used strategically.

Event Driven Architecture

Another key aspect of the Smart Grid Architecture is its ability to manage hundreds, or thousands, or even millions of transactions in such a way that events are generated, detected, and processed with pre-defined business logic and predictable conditions. An event can be considered as any notable condition that happens inside or outside your IT environment or your business. Usually, an event is detected as data and message flows between applications. An event in general could be a business event – such as detection of an outage condition or a system event such as failure of the MDM application to collect meter data. An event may also signify a problem, an exception, a predictable error, an impending problem, an opportunity, a threshold, or a deviation from the norm.

Given the transaction volume generated by Smart Meters, Smart Grid Architecture would also require a Management by Exception (MBE) capability where any error related to the integration of data and messages between systems and applications is captured, a trend identified and eventually addressed within a meaningful timeframe. In this case, MBE alludes to the capability where an abnormal condition, such as an exception, or an error requires special attention without any significant overhead or management on the rest of the system.

The Smart Grid Architecture should include an Event Driven Architecture (EDA) capability to process events as and when they occur with minimal human intervention.

The Future of Smart Grid Architecture

It is at this vital crossroad that the power industry has two choices:

1. To be proactive and have a strategy for managing Grid Operations & IT transformation through a strategic Smart Grid integration architecture; or,
2. To be reactive and tactical in responding to problems as they appear.

The latter approach is risky and will prove to be a major impediment to Smart Grid success. However, for those willing to take the proactive road, success or failure could rely squarely on the approach to solving the core IT challenges. For Meter Data Management, there are the inherent challenges of data volume, transaction performance, event handling and database performance as outlined below.

The Data Volume Challenge

As Meter Data Management products and applications are being employed to collect the data for various Smart Grid initiatives, these programs call for collecting huge volumes of meter data on a 15-minute interval basis. For a million meters, this data amounts to roughly 1,111 TPS (transactions per second).

Transaction Volume =1,000,000/(15 x 60) = 1,111 tps

Challenge: High Transaction Volume & Distributed Transactions

If each transaction is 1,000 bytes (1Kb) then 1Kb x 1111 transactions = 1,111 Kb are required per second. This is equal to 1Mb of data gathering and storage per second. Data Collected Per Hour = 1 MB x 60 x 60 = 3.6GB. This is equal to 85GB per day; 2.6TB per month; and 30 TB per year.

Challenge: Data Volume & Performance

Transactional data collected from customer meters can quickly reach staggering proportions that will require significant storage capacity and an information life cycle management approach to managing the data based upon some strategic approach where the value of data or at least that level of granularity, will gradually diminish over time.

Transaction Performance Challenge

Transaction performance is critical to the success of any system. Many SG & DR projects are hitting performance bottlenecks due to architectural constraints. Energy companies might consider the TPC-APP Benchmark™ as a way to measure their application performance. TPC-C is a transaction processing benchmark that can be used to do performance related planning that might be required to manage the transaction load and throughput.

Consider an AMI/AMR project that requires collection of data from a million smart-meters at 15-minute intervals. Per the previous section, the transaction volume is equal to 1,111 tps. This is equal to over 90 million transactions per day. The sheer handling of such transaction load may be a significant challenge and will require careful planning and selection of the appropriate communication technologies and MDM vendors. In addition to collecting the data, an organization will need to manage performance and storage challenges.

Event Handling Performance Challenge

A Complex Event Processing infrastructure is required to detect system and business events. This infrastructure will need to detect events "just-in-time". With over 90 million records, the detection of a "needle in a haystack" must work day after day, month after month, with little to no room for error.

If any of the transactions is a "last gasp", then such events will require tracking and action. One could assume that there may be 0.01% chance or 1 in every 10,000 meters that may send a last-gasp every day. As a result there may be about 100 last-gasp messages per day that require a business action like automated self-healing or a work order creation and crew-dispatch. Either way, such a transaction needs to be processed when it occurs.

Database Performance Challenge

A large volume of transactions will also need to be written into the database. At the rate of 1,000 - about 90 million transactions may be written in a day. In some instances, to narrow down an outage, the last gasp meter data may need to be accessed from the ever-growing transactional

database (as shown in Data Volume section) resulting in significant performance bottlenecks in database I/O. In this example, if there is 30 days worth of data in the database, then database records that will have to be searched = 90 million x 30 days = 2.7 billion records. This may result in serious database performance issues. Optimizing the database indexes and parallelizing the databases will be a pre-requisite.

Leveraging the Data – We're Going to Need a Bigger Boat

There are many other IT challenges that that must be addressed as organizations launch SG & DR programs. However, one final challenge for the purpose of this article is the issue of reporting and leveraging data warehouses. To date, corporate or enterprise data warehouses have not been a norm in the power industry. Reporting needs have been met traditionally through the use of operational reports taken directly from the transactional systems. Going forward, the status quo is not the recommended approach, due to the fact that when real SG & DR programs are launched, IT will have a transactional database requiring high throughput and large data volumes, as previously illustrated. In addition, reporting off of transactional systems may reduce application performance and impact other critical systems.

Additionally, once organizations are able to mine volumes of usage, outage data, peak load and other market and operational data that will be collected from Smart Meters and other applications, this information will need to be sourced and consolidated from disparate systems such as meter readings from MDM, operational data from SCADA, customer data from CIS and outage data from OMS. With so much actionable intelligence at stake, transactional systems should not be used to perform reporting. Instead an enterprise data warehouse should be developed that leverages data from the transactional system to do historic reporting, trend analysis, ad-hoc reporting, "what-if" analytics, better planning, and forecasting. Such data can also be used to improve customer service, lower cost of operation, increase grid reliability, and improve market operations.

Successfully tackling these challenges will enable organizations to clearly execute on their vision of developing a Real-Time Integration Architecture that will serve as a foundation for all SG & DR programs.

Making Smart Grid a Reality

Given the critical role that IT systems will play in concert with MDM and AMI/AMR projects, many of the decisions for Smart Grid & Demand Response initiatives will originate from the programmable business rules, and SG & DR applications resident within the IT realm. Transactions such as triggers to connect/disconnect a customer's Smart Meter could originate from the CIS application, perhaps based upon a change in customer status, or an outage pattern could be detected based upon consistent "last-gasp" reads from a localized set of meters.

The ambitious objectives of Smart Grid, when combined with some early warning signs from those who've embarked on the journey, indicate that the role and complexity of IT is being grossly under-estimated, and that IT is going to play a more prominent, if not dominant, role in making Smart Grid a reality. The Power industry needs to take a careful, hard look at these indicators, do appropriate course correction and reconcile with the role that IT will play in Smart Grid and Demand Response programs. IT will need to develop a Strategic "Smart Grid Architecture" as opposed to an "Accidental Architecture."

The bottom line is that IT systems will be integral to increasing the reliability of the grid and empowering customers with new demand response programs as more smart meters are deployed across the nation. Organizations implementing SG & DR programs based on strategic vision, planning and an architectural approach will ultimately be the leaders in making Smart Grid a reality. ■

About the Author

Tony Giroti is the Chairman & CEO of BRIDGE Energy Group Inc. and has over 23 years of experience in managing information technology products, platforms and applications. He is a Board Member of OASIS and member of the Smart Grid Architecture Committee, U.S. NIST. Tony is the former Chairman of the IEEE; Past President of the IEEE Power Engineering Society; Chairman CISA/ISACA New England; and former President, CEO and Chairman of two venture capital-backed global technology companies. Mr. Giroti is a certified information systems auditor (CISA) and has been granted four patents in the areas of SOA/XML/IT platforms.

After completing his Bachelor of Science in Electrical Engineering, Mr. Giroti trained at Crompton Greaves Ltd. in the Power Systems division designing large transformers. He also holds a Master of Science in Electrical and Computer Engineering from the University of Massachusetts.

Internet Standards Come to the Advanced Metering Infrastructure

By Roland Acra, CEO
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The AMI industry faces challenges today that were not anticipated even a year ago, when the industry was abuzz with news of smart meter rollouts and talk of pending IPOs. Now Congress has shelved the national energy bill, deeming it too difficult to pass in a mid-term election year, and California's groundbreaking energy legislation (AB 32) is threatened with suspension by a ballot measure, pushing the regulatory impetus for energy efficiency even farther into the future. Calls for balancing the federal budget are dimming the prospects of a renewal beyond next year of the Recovery Act funding for smart grid investments. A wary and skeptical public is scrutinizing the smart meters themselves. And public utility commissions are putting the brakes on the utilities' plans to roll out smart meters that may become obsolete in less than five years due to a lack of standards[1] or transferring the cost of upgrading those early meters to the ratepayers.

While the first of these problems are political – and beyond the control of the AMI industry – the last two may in fact be helped by standardization. This article surveys the efforts under way to converge on standards for the AMI industry that will mitigate obsolescence (and may thus help ease the public's fears of smart meters) and examines the key standards themselves.

The AMI landscape is currently dominated by a few pioneering and innovative vendors who have literally created the industry from scratch. As is common in these situations, each player has created solutions based on its particular strengths. But, because these solutions are not interoperable, a utility is forced to select a single vendor for all components of the AMI system, rendering the utility susceptible to the risks of vendor consolidation that must occur in any new market. This proprietary environment, while it initially spurred the nascent industry's growth by helping to raise awareness of the benefits of AMI, is now acting as a limiting factor on the rapid expansion of AMI networks.

Add to this the longevity of metering equipment (15-20 years), the comparatively short lifespan of networking technology (five years), and the even shorter lifespan of software (18 months), and it is clear that standards are the only way to achieve an operational model wherein each AMI component can evolve independently without compromising the whole architecture. All players recognize the need for standards, including the government, which has issued a clear call for smart grid standards and is taking a proactive role in coordinating their development.

Before examining the forthcoming AMI standards, it is worth taking note of a comparable standardization effort that has succeeded well beyond the expectations of anyone involved in the industry at the outset – the global Internet. The scale of an AMI network is in fact very nearly the same as the Internet and those wired and wireless broadband networks deployed worldwide over the past 15 years. The Internet consists of hundreds of millions of consumer devices (PCs, laptops, mobile phones, game consoles, etc.), all interacting with Internet-based servers by communicating over a network of diverse physical networks all "speaking" the IP protocol. Furthermore, as a public network, the Internet constantly faces the dual challenges of securing the network infrastructure and protecting the end devices from attack – and meets these challenges successfully.

Like the Internet, an AMI network consists of millions of devices – in this case, smart meters in a utility company's service territory. Millions more devices may join the AMI network in the future: Home Area Network (HAN) devices such as Programmable Communicating Thermostats (PCTs) and other load-control devices, dedicated energy management displays, Plug-in Electric Vehicles (PEVs), and distributed power-generation devices (e.g., inverters for solar arrays on home and business rooftops).

[1] Maryland Public Services Commission; Case No. 9208; Order No. 38410

Organizations and Their Roles in AMI Standardization

- NIST, the National Institute of Standards and Technology (part of the Department of Commerce), is coordinating the standardization efforts for the entire smart grid, with contributions from other organizations in their respective areas of expertise and focus.
- IEEE, the Institute of Electrical and Electronics Engineers, is working to standardize the MAC and physical layers of wireless AMI networks.
- IETF, the Internet Engineering Task Force, is working to define the IP routing and adaptation layer protocols to enable efficient IP implementation over emerging link technologies from IEEE that are relevant to AMI networks.
- W3C, the World Wide Web Consortium, is working to standardize the message formats for efficient data delivery over AMI networks.
- IEC, the International Electrotechnical Commission, is defining the common information models for AMI and the smart grid.
- UCAIug, the Utility Communications Architecture International Users Group, has, through its OpenHAN working group, led the efforts to define the requirements for devices communicating over the HAN.
- The ZigBee Alliance is an industry organization that has led the effort to define the Smart Energy Profile, a common information model for in-home control and display devices.

Figure 1: AMI System Overview

In addition to AMI and HAN devices, smart grid networks also include generation, transmission and distribution automation networks with hundreds of thousands of controllers and sensors. The challenge the smart grid industry faces today, then, is not that we don't know how to solve the problems of a huge internetwork similar to the Internet, but that we need to solve the problem RAPIDLY, so as not to lose industry momentum and public confidence.

With this in mind, it becomes clear why many of the standards being pursued for the AMI are in fact the same IP standards that power the Internet; and the public forums and organizations where they are being debated and finalized have familiar names: IETF, IEEE, and W3C. Other organizations leading AMI standardization are less familiar in the Internet arena but no strangers to the utility industry: IEC and UCAIug. Coordinating all of these groups' efforts is the NIST's Smart Grid Interoperability Panel (SGIP), using a process known as the Priority Action Plans (PAPs) for addressing critical gaps in smart grid standards, of which AMI is one. (Network communications and cyber security are others.)

Figure 1 illustrates the components of an AMI system. HANs (Home Area Networks), typically considered Customer Premise Equipment (CPE) and not included in the AMI, are shown here for completeness. Collection networks for meter data, referred to in Figure 1 as Neighborhood Area Networks (NANs), may be any one of wireless, cellular, power-line, etc. The utility Wide Area Networks (WANs) may similarly be private or public Wi-Fi, T1, WiMAX, fiber or cellular networks. NIST has strongly encouraged the industry to converge on IP standards over any of the link types above for this and other internetworking components of AMI and the smart grid.

Gaps in the IP standards are being addressed by IETF working groups. The IEEE 802.15.4 committee is addressing the gaps for cost-effective, unlicensed spectrum-based wireless mesh NANs at the physical and MAC (Media Access Control) layers. W3C committees are addressing end-to-end messaging and formats. The IEC has created the common information models for AMI.

Figure 2 illustrates the protocol layering of the AMI communications stack for wireless mesh networks. Wireless mesh networking is well matched to the AMI collection networks in North America, with its lower density of homes compared to some parts of Europe and Asia (where power-line communication, or PLC, may be quite cost-effective), and its wider geographical spreads within cities, towns and neighborhoods. Another distinct advantage to wireless is the coverage it provides for non-electric meters such as gas and water.

In these cases, long-life batteries can power the meter communications, and the meters may be considered "constrained devices" (low-power consuming). Even in electric meters, stored-energy-operated (e.g., using super-capacitors) wireless communication has the benefit of providing meter connectivity during power outages, when that connectivity – and the resulting remote visibility – is at a premium.

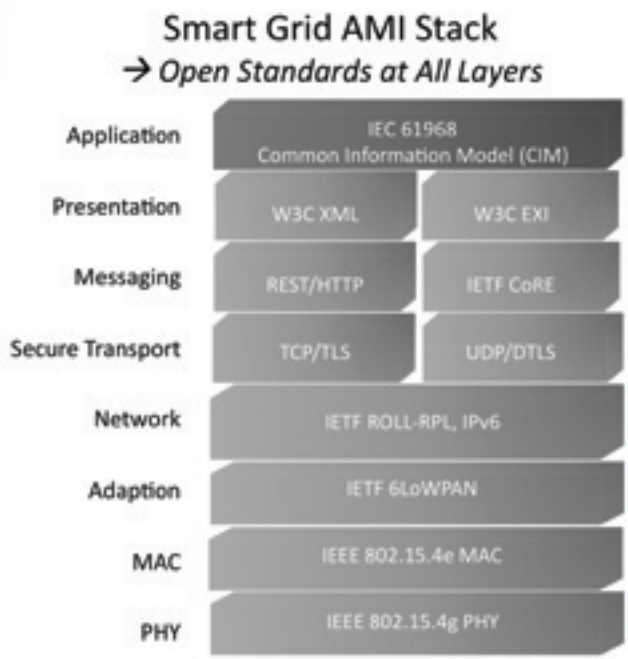

Figure 2: AMI Protocol Stack

Let us examine each of the standards in some detail...

At the highest layer of the AMI, Meter Data Management Systems (MDMSs) need to have a common understanding of the capabilities of a variety of meters from a number of different vendors. The Common Information Model (CIM) standardized by IEC addresses this requirement via the standards suite 61968. This set of standards encompasses many aspects of utility operations, from customer support to network planning, operations and maintenance, to records and asset management. In particular, IEC 61968-9 governs the meter reading and control functions, including data collection, service connect/disconnect, service outage detect/confirm, and reset.

The meter-based layout of data is standardized by ANSI and called C12.19. Application-layer protocols for transporting the meter data have ranged from entirely proprietary representation and transport of meter data, to proprietary transport of C12.19 data, to use of another ANSI standard called C12.22. However, the more modern and future-proof implementation of the above applications relies on web-centric paradigms (HTTP and XML) while making those especially efficient over the new resource-constrained but cost-effective collection networks for AMI.

The format of the data exchanged between the meter and the MDMS is XML, which is a W3C standard. However, in constrained devices and networks, the sheer volume of XML data needs to be pared down significantly. The W3C and IETF are defining a pair of standards to address this need. EXI (Efficient XML Interchange) is a W3C draft that implements a compact and efficient representation of XML that the meter can use to encode meter data tables and that the head-end can then "uncompress" back into XML, which the MDMS can use to decode them. The IETF's CoRE (Constrained RESTful Environments) working group has a draft for a messaging protocol (Constrained Application Protocol, or CoAP) over constrained networks that is similar to HTTP "GET" and "POST" messages, but much more compact and efficient.

At the transport layer, TCP (Transmission Control Protocol) and UDP (User Datagram Protocol), along with their secure counterparts TLS (Transport Layer Security) and DTLS (Datagram Transport Layer Security), will carry the end-to-end data (from meter to head-end) over a variety of physical networks (NAN, WAN) using IP routing.

At the routing layer, the IETF RoLL (Routing over Low-power and "Lossy" Networks) Working Group defines a new IP routing protocol called RPL (Routing Protocol for Low-power and Lossy Networks) between embedded devices with limited bandwidth, power, memory and processing resources. These devices can be interconnected through a variety of links, such as IEEE 802.15.4, Bluetooth, low-power WiFi, wired or other power-line communication links. Some of RPL's vital features for AMI include multi-hop mesh routing, robust operation in the presence of packet loss, and efficient implementations in constrained network nodes with limited power.

The IETF working group 6LoWPAN (IPv6 over Low-power Wireless Personal Area Networks) has already defined the adaptation layer for IPv6 over IEEE 802.15.4 networks. The benefits of IPv6 for the AMI include a large IP address space to accommodate virtually unlimited growth of meters and other end-devices, and "plug and play" capabilities of IPv6 such as stateless auto-configuration of devices.

At the MAC layer for low-power wireless networks, the proposed IEEE 802.15.4e standard enhances the 802.15.4 MAC with MAC-layer security, industrial-grade robustness including frequency diversity via hopping, and low-energy operation.

Definition of new physical layers by the Smart Utility Networks Task Group – IEEE 802.15.4g – is providing global standards on radio communications and enhanced minimal throughput including in the sub-GHz license-free frequency bands. This opens the door to standards-based semiconductor offerings from the leading radio transceiver vendors, with expected volume-based cost improvements, in contrast to the very sub-optimal current situation in which each AMI vendor offers its own in-house, proprietary and (to the utility) cost-inefficient radio implementation.

The smart grid will doubtless increase the power grid's efficiency and bring unprecedented opportunities for energy savings, but it will also create a number of operational challenges. Security is at the top of that list. Some even claim that the use of TCP/IP may itself represent a security issue. But the adoption of the TCP/IP architecture and associated standards by the smart grid industry does NOT mean that a utility's private resources will be exposed to all Internet users. Even today, the Internet is a collection of public and private networking infrastructures running IP everywhere, with each organization free to decide how to set its level of security by publicly exposing all, some or none of its networked resources.

Furthermore, the Internet represents the largest possible community effort and knowledge database for monitoring, analyzing and fixing flaws and threats – something no closed and proprietary system could ever hope to achieve. The old paradigm of "security by obscurity," referring to the false premise that proprietary networks are somehow more secure, has long been rejected by the security community. The belief is that the open protocols and paradigms are by far the most secure ones, given their maturity and the thorough understanding of their vulnerabilities and threat models, for which remedies have been found and incorporated.

Years of experience in the Internet community have led to the development of effective IP security standards, security products and solutions (e.g., firewall, intrusion prevention, encryption), best practices and policies (access control, traffic filtering, security zones, virtual private networks) and their adoption by all organizations connecting to the Internet. These clearly apply to the smart grid infrastructure. Open standards and protocols have driven cooperation on security, enabling global teams to identify, inform and fix security issues. Organizations such as the Computer Emergency Response Team (CERT), the CERT Coordination Center, and the Computer Security Incident Response Team (CSIRT) are collaborating with vendors. Utilities deploying smart grid infrastructures can leverage and benefit from this collaboration.

Generally speaking, the Internet protocols may in fact represent our best opportunity to rapidly converge on a set of standards for the networking aspects of the smart grid. At a time when the industry faces many challenges, this is a very timely and welcome opportunity to reassure the public and regulators that development of the smart grid will not be slowed by the lack of standards – or the early obsolescence that would be its logical consequence. ■

About the Authors

Roland Acra joined Arch Rock as president and CEO in December 2005. Prior to Arch Rock, he was President and CEO at Procket Networks, a high-end core Internet router manufacturer, which he successfully led to an acquisition by Cisco Systems in 2004. Before that, Acra held several senior management positions at Cisco Systems from 1991 to 2003, including senior vice president and chief technology officer, group vice president and general manager of the Public Carrier IP Group, general manager of the Remote Access Business Unit and technical director of Cisco in EMEA. Acra holds Diplome d'Ingenieur degrees from Ecole Polytechnique and Ecole Nationale Superieure des Telecommunications (Paris, France).

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The Human Side of Smart Grid

Utilities that fail to look beyond the technology of Smart Grid do so at their own peril

By Tim Wolf, (former) Senior Director, R.W. Beck – An SAIC Company
Seattle, Washington USA

In October 2001, Apple's CEO Steve Jobs stood on a stage in blue jeans before an auditorium of invited journalists to unveil Apple's newest product and first foray into consumer electronics, the iPod. The audience was polite but somewhat skeptical at the time, particularly about the $400 initial retail price. Now, after 10 billion songs have been sold on iTunes according to Apple, it is quite clear that the digitization of music and the iPod eviscerated the business model for the music industry and left record companies flatfooted, defensive, and dumbfounded about how to respond.

Whether it is music (the iPod), books (the Amazon Kindle), imagery (digital cameras), or movies (Redbox), the brief history of the "digital" revolution is replete with winners and losers, innovators and followers, and clear lessons that new, disruptive technologies drive fundamental changes in the business model rather than vice versa.

But what about the energy industry?

While we have not yet – in Steve Jobs' words – "found the recipe" for the Smart Grid, the shopping list is largely written and many utilities are now in the kitchen. Further, companies such as Google and Microsoft as well as a dozen start-ups searching for the recipe expect the utility business to foot the bill for the underlying technology as they take the customer high ground.

The convergence of Smart Grid technologies with consumer electronics, wireless communication networks, and the Internet will enable what all the attempts at deregulation have failed to: the creation of a platform for true customer choice and a sea change in how customers buy, use, and perceive energy. One of the things that has made the iPod so successful is that Apple has focused so effectively on the wants and needs of the end user to deliver ease of use, freedom, and true value. And there is money to be made in this rapidly emerging market space. That's why many companies such as Google, Microsoft, Intel, and Cisco are entering the Smart Grid market space with new energy management products, software platforms, and services to get in on what has always been the utilities' private domain. The deployment of Smart Grid technologies brings with it significant threats and opportunities for the traditional utility franchise—depending on how the utility decides to approach it.

It won't be easy!

The Smart Grid technology revolution will require utilities of all types and sizes to develop new business and investment models, new business processes, new skill sets, new ratemaking strategies, new programs, and a laser-like focus on the customer. These challenges presented by the "Human Side of Smart Grid" may well prove to overshadow the technology challenges, as utilities struggle to adapt their organizations and implement effective change management programs to a landscape that is rapidly shifting under their feet.

Today, according the Edison Foundation's Institute for Energy Efficiency, there are less than 10 million truly smart meters (with two-way communication) deployed at utilities in the U.S. The American Recovery and Reinvestment Act's Smart Grid Investment Grant (SGIG) program will support the deployment of an additional 18 million smart meters over the next three years. And this does not include the ongoing or planned advanced metering infrastructure (AMI) deployments by utilities that did not ask for, or receive SGIG monies. That means by 2015, as the adoption curve steepens, there will be some 30 million smart meters deployed. By 2019, that figure is expected to nearly double to almost 60 million smart meters.

Think about it. Utilities will be adding tens of millions of intelligent, near real-time, two-way communicating "computers" to the side of everyone's house, so say nothing of the millions of devices – from programmable communicating thermostats to in-home displays to smart appliances – that will be installed behind the meter. If we as an industry, steeped in a nearly century-old, protected business model, think we know exactly how all this will turn out, what sort of innovation will be unleashed, and how customers will respond, we are kidding ourselves.

What is clear is that faced with higher prices and desiring higher levels of service, consumers will react and make choices. Utilities that innovate and work with their regulators or governance boards to adapt – even transform – their business models, will find themselves in a much stronger position to shape their future. Those that do not may well have their future shaped for them. And, all the while, the expenses for building out support systems in areas such as billing and control will be left with the regulated business as newcomers grab customer attention and revenue. There is a significant chance of stranded assets as utilities build infrastructure only to have the fruits of their labor taken by other firms.

To stay ahead of the disruption curve of Smart Grid, utilities must move beyond the mere technical questions and orchestrate a cultural shift that results in a new level of focus on their organizations and their customers. This is not to suggest that utilities do not currently do so, but rather that they must shift their focus to the context of a new business model in which real-time information, communication, control, and customer interaction are the norm.

Inside the Utility

The planning and implementation of a Smart Grid initiative is a complex endeavor that will fundamentally transform the way a utility delivers energy and the way its customers use energy. The effort will cut a wide swath and impact a broad array of stakeholders across the organization. And though the technologies involved are critically important, the success of any utility's Smart Grid initiative will also depend on non-technological elements such as change management; solid program design; rate analysis and development; marketing, communication and outreach to customers; and building a project atmosphere and organizational culture of innovation and openness to change within the utility.

Over the course of dozens of Smart Grid and AMI projects over the past two years, R.W. Beck has found the following elements are essential to building a foundation for Smart Grid success within the utility organization.

A Clear Vision and Strategy

Where does the utility want to be in 10 or 20 years? What will it look like; how will it operate; and what goals are to be achieved? Without a common, unifying vision that is broadly understood throughout the organization, it becomes very challenging to transcend the organization's traditional silos and barriers. Strong support and buy-in from the entire senior management team is equally critical. The visioning exercise for Smart Grid is efficient and straightforward and is readily harmonized with the utility's enterprise resource planning and strategic planning.

The vision is supported by a strategic messaging map that provides a clear set of "home base" messages that articulate the purpose, goals, and value proposition of Smart Grid in a clear and compelling way to both internal and external stakeholders. If executed correctly, all communications about the project will clearly map back to the core strategic messages to help ensure understanding, organizational alignment, and a broad base of support.

Technology Road-mapping – A View from the Future

Taking place a level down from the vision and strategy development, the technology road-mapping process assesses the current technology landscape at the utility and the business goals and objectives supported. The process challenges the utility to honestly explore 10 or more years into the future with respect to its mission and business drivers. Participants envision a future state consistent with the utility's mission then work backward from that state, defining the steps, the sequence of technology investments, and the dependencies to get there. The technology roadmap contains both strategic and tactical elements and must remain a living document that can be updated as new conditions arise.

With the roadmap in place, senior management has a valuable tool and well defined technology pathway to prioritize capital investments across the organization, align utility activities with strategic planning, and enable utility employees to better understand and support the strategic direction because they see where they're heading.

Whether it's AMI, outage management, distribution automation, integration of renewables, mass-market demand response, distributed generation, or energy storage, the technology roadmap provides the basis for integrated, effective decision making at both the strategic and operational levels.

Business Process Redesign

A key element to ensuring strong return on the Smart Grid investment is to re-engineer, streamline, or even eliminate business processes to take advantage of the capabilities of the technology and the value of the data the systems deliver. R.W. Beck's experience has shown that a focused business process re-engineering effort to streamline internal processes is one of the most valuable endeavors the utility can undertake in concert with AMI/Smart Grid deployment.

The process starts with the utility management team identifying the business functions that will be impacted by implementing Smart Grid technologies. The process then digs deeper to capture the work processes to support those functions. From there, it's a matter of prioritization – identifying the business process opportunities that will deliver the greatest value to the utility and its customers. Developing honest, accurate assessments of the current state is critical.

As the process moves forward, team members lay out those processes and deconstruct them, always asking the questions "Why?" and "What if?" From there, the teams work collaboratively to define a future state for each of the processes based on the capabilities of the systems and data they provide.

The future state is then laid over the current state to fully identify the required changes to implement the new process. These inputs include resource requirements (organization, staff, systems), as well as upstream and downstream dependencies. The key consideration during the business process redesign phase is to identify the low-hanging fruit: those processes that can be re-engineered and implemented in the near term to optimize the return on technology investment.

Organizational Refinement

AMI and Smart Grid are transformational technologies that bring with them significant changes and far reaching impacts on how a utility will run its business, how it will interact with customers, how data will be managed and applied, and how energy will be delivered and used. Therefore, the Smart Grid utility will require new and different skill sets as well as organizational structures to optimize performance and return on technology investment.

The organizational refinement process involves tough choices. People's jobs may disappear or change dramatically. In the typical utility we see management teams and workforces that can be segmented into three groups regarding their receptiveness to change. About one-third of the people in a typical organization are change agents. Another third are "on the fence" about whether change is a good thing. The final third are resistant. Focus change management efforts in the context of the established vision and technology roadmap on the middle third to tip the scales for the organization in the right direction.

Internal Stakeholder Engagement and Communication

Internal utility stakeholders hold the key to Smart Grid success. They will implement and operate the Smart Grid, and their involvement and understanding from the beginning is critical. The senior management team must commit the time and effort to meet with employees across all groups, evangelize the vision and strategy, and maintain that effort until alignment and inertia to move the project forward take firm hold. This internal communication effort must be continued throughout the project based on a comprehensive communication plan and messaging map established early in the process.

Outside the Utility

In March of this year (2010), a Harris Poll of 2,576 adults in the U.S. gauged public attitudes toward electricity consumption and the Smart Grid. While the poll provided interesting and timely insight into consumer thinking, it also underscored the great need for education and outreach to consumers about the purpose and need for Smart Grid. Among the findings:

- When asked if they've ever heard the term "Smart Grid," 68 percent said "no" and 32 percent said "yes." When asked if they had ever heard the term "Smart Meter," only 26 percent said "yes," while 69 percent said "no" and 9 percent were "unsure."

- When asked if they would be willing to pay 10 percent more right now for electricity each month to get the benefits of Smart Grid in the future, nearly half responded negatively.

- Two in five (42 percent) Americans were unable to agree or disagree with the statement, "The electricity system is fine the way it is, and Smart Grid is not necessary."

- When asked about the impact of Smart Grid on the security, reliability, and increased renewable sources of energy on the electric system, at least one-half of Americans expressed uncertainty.

- The general population is also uncertain about what will happen to the cost of electricity once these investments are made, and as such are very unwilling to pay for it. Those familiar with Smart Grid are more likely to believe that the cost of electricity will increase once it is deployed (51 percent) than those who have not heard of Smart Grid (39 percent).

"While the need for and benefits of Smart Grid and smart meter may seem obvious to industry insiders, this is not the case with consumers. In light of the huge investments about to be made that ratepayers will ultimately be responsible for, utility companies need to formulate, test, and launch a sustained communication strategy," said Tish Pasqual, senior research director, Harris Interactive Business and Industrial, Harris Interactive.

This dearth of knowledge and familiarity with Smart Grid and AMI is likely a strong contributing factor to consumer unrest associated with Pacific Gas & Electric's deployment of smart meters in Bakersfield, California. There a state legislator is seeking a suspension of all smart meter installations in the state until the meter accuracy controversy is resolved through an independent assessment. This issue is now spilling over into the Texas market as well.

While those of us who have worked in the metering industry for a while know that today's solid-state meters are highly accurate measurement devices – more accurate than their electromechanical forbearers across the entire load curve – the public is skeptical (particularly when the utility is asking them to pay for hundreds of millions of dollars for the meters).

Yet despite PG&E's best efforts to explain that the higher bills associated with the smart meters is attributable to weather and rate increases, many consumers, consumer advocates, and politicians aren't buying that. Instead they see that customers received smart meters and bills went up, so they assume that smart meters must be the cause.

Customer Perceptions Rule

The results of the Harris Poll and the trouble in Bakersfield underscore the point that technology is only part of the Smart Grid recipe. Significant education and sustained customer outreach will be required to ensure that AMI technology is accepted, but that's just the first step. Changing customer perceptions about energy usage and costs will be critical to driving meaningful adoption of programs – time of use (TOU) pricing/ critical peak pricing (CPP), demand response, load control etc. – that actually deliver the value and outcomes that Smart Grid promises.

Voluntary TOU programs have been in place for 25 years or more, and to this date, adoption remains woefully low. An entirely new and challenging period of rate analysis and design will be required to create the economic incentive to make customer participation worthwhile. In the next couple of years, we will likely see programmable communicating thermostats, in-home displays, and perhaps even smart appliances available at retail outlets such as Home Depot and Lowe's.

What happens when a consumer buys one, comes home and installs it, and it doesn't configure properly with the meter and home area network? Do they call the utility? Do they call the device manufacturer? Who fills that need in the marketplace if the utility decides it doesn't want to deal with anything beyond the meter?

These are just some of the challenging questions the industry will have to wrestle with and communicate clearly to consumers as Smart Grid becomes a reality in people's homes. As with every other product or service, consumers will be seeking value and ease of use. Apple's mantra in developing the iPod was "if you make it easy, the customers will come." Utilities who take a page from the Apple playbook, and focus on the user, will find themselves in a much better position as Smart Grid rolls out. ■

About the Author

Tim Wolf is a consultant focusing on AMI and Smart Grid; formerly with R.W. Beck, an SAIC company.

Communications: Making Smart Grid Sing More Than AMI Songs

By Lisa Ludwig, Vice President – Smart Grid Markets & Applications, Ambient Corporation
Newton, Massachusetts USA

Taking a look at the federal grants and stimulus packages, one would be led to believe that "smart grid" equals "smart meter". If only it were that simple. Some utilities are furiously charging forward, installing smart meters and slapping communications devices on poles and transformers of the distribution grid. But after this is done, more questions may come to mind only too late. What do you mean we can't deploy a different brand of meters? Why doesn't the communications node support various meter types or meter models? And why do we have to buy separate communications devices to support sensing for voltage and current reads? The answers can get pretty ugly. So let's face it, a little planning up front can go a long way to cost savings, facilitating future deployments, and getting the most out of the smart grid. Don't be a "one-hit AMI wonder" when you can make several smart grid hits on your communications strategy album. Here's how...

Composing the Best Communications Solution

There are two key areas of consideration for your communications strategy: 1) smart grid applications desired beyond Advanced Metering Infrastructure (AMI) and 2) understanding the communications technology options that best suit the applications. Let's examine this duet in further detail.

Applications: The Tracks for Your Smart Grid Album

Smart Grid Application Songs. So why do you need to think about smart grid applications beyond AMI now? What's the big deal? Let's start with an example. Many vendors offer an "AMI solution" that includes both the meters and communications device that delivers the meter reads to the utility. In this scenario, most have engineered the communications device with a proprietary interface to work only with a single meter brand. This is perhaps the most direct path to finding yourself locked in to a single meter supplier. It can be a baffling experience when you learn later that you can't add additional meters from the same vendor that are different model numbers from the original deployment! Furthermore, it can also be frustrating to find the communications devices used in the original deployment are not interoperable with other brands of electric meters or other types of utility meters for water and gas.

Now let's go beyond meters; do you want to entertain the opportunity to do monitoring and sensing? Measuring voltage, current, or something else? Do you want to be able to do partial discharge monitoring? Or do you want to focus on demand response applications such as peak load management or distributed generation? Obviously, it's hard to know what you'll need in ten years. But smart grid is a long-term investment so you'll want your songs to continue to be hits for years to come.

Data Volumes and Tempo. Once you've figured out which applications will be most beneficial to your utility operations, you'll need to size the data that these applications generate and scale your songs appropriately. Obviously, a little tap dancing will be required to come up with the numbers, but a calculator in hand and some assumptions will help.

For example, consider the amount of data and how often the data must be transmitted to the utility's operations center. New electric meters can be configured to deliver once-a-month meter reads, hourly reads, or a fast tempo with reads at 15- minute intervals. Even if the same meter is used for each of the scenarios, the first scenario requires 12 messages a year, whereas the last scenario requires 35,040. Extrapolate this data increase across hundreds of thousands – ultimately millions – of meters, and the enabling communications requirements look very different. The nature of the data volume and tempo will dictate what network protocol options for are best suited for your applications.

Selecting Communications in Rhythm with Your Smart Grid Applications

Now that you've done your homework, having come up with the requirements or at least a wish list for smart grid applications, where do you start your quest for the ideal communications solution? What should you be looking for when evaluating communications nodes? Unless you want the one-hit AMI wonder, you can't go wrong with the following chromatics to compose a harmonious communications solution.

Hitting All the Notes on the Technology Scale

- **Flexible Interface.** A flexible interface that can communicate with any IP-based device such as electric meters, gas meters, and distribution line sensors is key to leveraging current and future applications for the smart grid. Examples of applications derived from a flexible interface could include energy sensing for current and voltage levels or a partial discharge monitor that detects deterioration in power cables before they fail.

- **Support for Multiple Network Protocols.** Also key to enabling smart grid applications is a solution that supports multiple network protocols. The communications node should be configurable to the protocols required in various scenarios. Examples include Ethernet and serial ports, cellular, IEEE 802.11 (a/b/g) Wi-Fi, and Power-line Communications (PLC), and RF. The applications and environment will dictate which protocols are best suited for the smart grid communications solution.

- **Layered Security.** The communications nodes should be protected both at the physical and logical levels. The physical device should be encased in such a way that it cannot be opened by anyone who is not authorized (for example, a padlock). The logical level includes network and system access. SSH encrypted login should be available for network access. While system access should also support password encryption. Further, there should be varying levels of system access for users (i.e., normal vs. root).

- **Mounting Options.** Depending on the application and entry points on the grid, various mounting options should be available with the communications device selected. (Also, keep in mind that the optimal mounting scenario includes a single communications device with a small form factor.) The first and most obvious mounting option should include brackets for attaching the communications node to the utility pole or wall. Additionally, a kit that allows the node to be securely fixed to a transformer pad without having to modify the transformer cabinet should be available as an option.

- **Weather Proof.** The communications unit should be able to handle a range of weather conditions, from severe heat to extreme cold, rain, snow, and whistling winds to name a few.

- **Automated Configuration.** Deployment time is an underestimated expense. Shortening deployment can enable a faster ROI. Look for a system that automatically activates and registers itself upon installation. No need for a long configuration prelude if you find the right vendor.

- **Backup Power Options.** Look for solutions that offer both extended backup power and short-term backup power. Extended backup power should allow a node to continue running for a minimum of 15 minutes when AC power is lost, enabling utilities to continue monitoring the distribution system during an outage. Short-term backup power typically maintains the nodes connectivity for a minimum of 2 minutes, allowing it enough time to send an alarm that an outage has occurred.

- **Remote Upgrades.** Remote upgrades save truck rolls and resources in terms of time and money. A top-notch remote upgrade system will upgrade any firmware or software on the communications node – including the node operating system, component firmware, and module applications.

- **Management and Reporting.** Software designed to manage communications nodes in the smart grid network should be available to utilities as part of the communications solution. Look for a vendor that has a Web-based solution. This will facilitate management of the network by enabling utility operations personnel access to the network status any time, from anywhere. In addition to the network management capabilities, the system should be designed to collect information from the nodes at various intervals and generate reports.

Cost Considerations

Assuming your evaluation encompasses the elements mentioned above, chances are you will indeed find a more cost-effective solution than taking the "one-hit wonder" approach. At this point vendors will be narrowed down and you will hone in on the features vs. cost chorus.

A Final (Power) Chord

The smart grid hype can make us all want to be AMI rock stars and overnight sensations. But it's important to remember that smart grid is a new and evolving style, and communications deployment mistakes now will make your album short-lived. Take the time to make sure your smart grid communications strategy will "rock on" for years to come. ■

About the Author

Lisa Ludwig is Vice President, Smart Grid Markets and Applications for Ambient Corporation. With over twenty years of high-tech experience, Lisa previously held executive roles in telecommunications, smart grid, security, and storage technology market segments. Prior to joining Ambient, Lisa was Senior Director at SEPATON, Inc., a virtual storage technology company focused on utilities, telecom and financial markets. Most notably, she was head of Ericsson's worldwide Network Management Business Unit. Lisa has authored many articles and papers for industry trade magazines and IEEE publications and holds a B.S. in Computer Science from Merrimack College in North Andover, Massachusetts.

EXECUTIVE Directions

Utilities Telecom Council

Bill Moroney, President & Chief Executive Officer

The Utilities Telecom Council (UTC) is the telecommunications and information technology trade association for electric and gas utilities, water companies, energy companies, and other critical infrastructure companies – including investor-, publicly- and cooperatively-owned – as well as their technology partners – all united in their commitment to ensuring the best, most reliable systems and networks critical to their core businesses and the customers they serve. Founded in 1948, UTC is now an international federation of direct business members and affiliated trade associations representing over 10,000 organizations serving all corners of the world and virtually every community in the North America. I recently talked with UTC's CEO, Bill Moroney, about UTC's role in utilities' communications from smart grids to emergency response and restoration. – *Ed.*

EET&D: It's probably best to start with how UTC fits into the overall mix of electricity and telecommunications trade associations, since there are actually quite a few of them…

MORONEY: Sure, Mike. The majority of our core members are energy or water utilities. Most major telecom service providers and equipment manufacturers belong to UTC as associate members, because they have a stake in our core members' success; but we exist to advocate for and help electric, gas and water utilities. The "telecom" part of our name speaks to the part of the utility that we support.

EET&D: This might seem like a silly question, but why the telecommunications emphasis?

MORONEY: Not at all; and the fact is, most people don't realize that utilities have built, own, and manage very extensive private communications networks all across the country. Utilities have their own fiber networks, microwave networks, and mobile radio communications systems. It is the people who design, build, and manage these networks – from the Chief Information Officer down to radio technicians – that UTC interacts with.

EET&D: But, how does UTC differ from the other electricity trade associations in Washington like the Edison Electric Institute, the American Public Power Association, and the National Rural Electric Cooperative Association?

MORONEY: For starters EEI, APPA, and NRECA are members of UTC along with about 10 other DC-based energy and water associations plus over 500 utilities and their technology partners. We have both utility organizations and trade associations as members. For their members, EEI, APPA, and NRECA are the absolute best representatives they can have in Washington. UTC's role is to represent all types of utilities on communications related issues. In addition, we focus on providing "anticipatory analysis" for our members from a cadre of senior staff legal, engineering, standards, and research experts.

EET&D: Is this focus on communications for utilities something new with the advent of smart grids or have utilities been in the communications business for a while?

MORONEY: Utilities started building their own communications networks in the 19th century with the application of telegraph technology to remote power facilities simply because we needed reliable communications to ensure the reliability of the energy grid in places that commercial communications providers could not make a business case to offer it. This is not a criticism of commercial providers, just recognition that we have very different business models.

In the early 20th century, utilities started using radio technologies long before most businesses. UTC was created in 1948 by utilities that had been using a variety of private communications networks for decades. Today, the industry is beginning to radically increase its reliance on 21st century information communications technology networks as we deploy smart grids.

EET&D: When you talk about utility telecommunications, exactly what are we talking about?

MORONEY: When we build giant solar and wind farms to add this great renewable energy source to the grid, this does not magically happen. It takes a fairly sophisticated communications system to control the integration of this variable energy source into an incredibly complex mix of energy resources and demands. Often these renewable energy sources are not located where commercial telecom networks exist.

Another example is when hurricanes strike, we are all moved to see utility bucket trucks among the first to respond to the emergency. What keeps these crews safe and makes them so effective are their private voice and data radio systems that are designed to work when the power is out for everyone else. Often, one of the first restoration jobs we have is getting power back on for the other emergency responders who do not have the kind of backup power that utilities have.

Overall, utilities' communications systems fall into at least one of four buckets: (1) smart control systems on the transmission and distribution grids down to the substation level; (2) smart edge devices like smart meters and distribution system monitors; (3) private mobile voice and data systems; and (4) traditional business enterprise systems like LANs and smart phones.

EET&D: Radio spectrum seems to be the top issue UTC has worked on over the years. Is that still the case?

MORONEY: Access to radio spectrum has always been very important for utilities. UTC was established specifically to help utilities cope with new spectrum regulations immediately following World War II. We still have a radio licensing and frequency coordination business – UTC Spectrum Services – that traces its origins back to those early days of UTC. Since then, our role has expanded beyond radio systems as utilities use of other technologies, notably fiber optics networks, has expanded.

Today, we are helping utilities assess new technologies and new offerings from commercial service providers. To illustrate how times have changed, we are just wrapping up a comprehensive study of how utilities use communications, outlining what their options are looking to the future, and suggesting ways each utility can assess when it is best to expand their own communications systems and when partnering with a commercial network might be better.

EET&D: But, isn't UTC trying to get an allocation of spectrum from the Federal government?

MORONEY: We are seeking to share, not take away, spectrum that the Federal government uses so that we can build smart control grids and emergency response communications systems faster and at less cost to the public than doing it without spectrum would dictate.

In the late 19th century, the U.S. government decided it would be in our national interest to have transcontinental railroads; and, so they said to the railroads, if you build it, we will give you the land you need.

Today, the clean environment and energy independence benefits of smart grids are equally, if not more, important to Americans as railroads were a hundred fifty years ago. Using secure spectrum to build out these networks would help us realize the promised benefits of smart grids far faster than waiting for more expensive solutions to be financed and built. Sharing government spectrum is how Canada has already helped utilities there; and the European Union is considering a similar sharing of spectrum with utilities there.

EET&D: Is spectrum the most important telecom/IT issue facing utilities today?

MORONEY: Spectrum is a value tool to implement the promise of what energy utilities will contribute to society in the years ahead, but the most important issue is data itself – managing massive amounts of new data, understanding what it all means, and keeping it secure will be the challenge for utilities in the decade ahead. On cyber security alone, utilities will spend far more time and money addressing this challenge and most are planning on it right now. We know that efforts to penetrate utilities' control networks and usage data are ongoing.

We also know that all types of individuals and organizations make these cyber attacks, ranging from disgruntled employees and hackers to common data thieves and foreign governments. To date, utilities have been fairly successful at stopping these attacks and catching the perpetrators; but logic says their numbers will increase and they'll get even better at in the future. The biggest problem utilities face today is conflicting messages from the Federal government on what to do, how much to do, and how to pay for it all.

Congress, NERC, FERC, and the Departments of Energy and Homeland Security are all proposing cyber security requirements; however, the best direction out there today are new smart grid security guidelines from the National Institute of Standards and Technology (NIST). This will sort itself out over the next few months, but addressing cyber security will dominate utilities' telecom and IT work in the months ahead.

EET&D: I notice that UTC's volunteer leadership has an annual strategic planning process that it uses to set priorities for the organization. Can you tell our readers a bit about how that works?

MORONEY: UTC is a technology organization that is not preoccupied with technology. Our purpose is to help those utility professionals with experience and responsibilities in the telecom and IT fields to use their skills to help achieve their organization's overall goals. Last year, when we started our strategic planning process, our Board identified four, overarching requirements:

1. Supporting utilities' need to address climate change policies;
2. Helping utilities contain costs while increasing investments in new technologies;
3. Managing the dramatic increase in telecom and IT regulations for utilities; and
4. Enabling improved cybersecurity for all utility systems.

And, it is from these four priorities that our policy, compliance, education, and information services evolve. All of us who work at UTC take a great deal of pride in being very good at supporting a member-driven organization. ■

SECURITY SESSIONS

Volume 2 No. 6

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

Merging and Converging Networks Change All the Rules!

Welcome to Security Sessions, a regular feature focused on security-related issues, policies and technologies. During the last couple of years I've had the opportunity to be involved with several generating plants going through upgrades and expansions and work with the plant, corporate and vendor personnel responsible for handling these various efforts. One facility was upgrading their automation systems; another was upgrading and expanding their security systems; and the third was replacing their antiquated telephone system. The people involved had years of experience with the systems and technologies at their respective plants, but in each of these three cases the plant personnel had limited or no experience with the state –of-the-art in any of the three areas being updated (i.e., plant automation, telecommunications and security). This lack of awareness led to misconceptions and security presumptions that were dangerously wrong. – ***Tim.***

Many years ago when the first of these plants was built, the telephone system they installed was a typical analog PBX system that provided voice-grade phone lines to all of the offices and various other locations on the site. It also supported the connection of FAX machines, dial in/out modems and could even support some dedicated, point-to-point circuits within the plant for interconnecting external systems and devices. Although the PBX had been updated a few times, it was still basically an analog telephone system. Their plan was to replace the old phone system with a modern VoIP (Voice over IP) telephone system. This in and of itself was not an issue. But they were thinking about the new phone system as if it were still an old analog PBX, presuming that it would continue to utilize dedicated wiring, when, in fact, the existing plant-wide LAN was actually going to be used for the new phone system.

In discussing the new digital VoIP phone system with the vendor – and with the plant telecom folks overseeing the upgrade – the picture became clearer. That is, the existing Ethernet switch network in the plant would now be expanded to reach every point where a phone was needed and/or currently existed, including some located in obscure locations along the periphery of plant grounds. And, as one might expect, that same LAN network supported the desktop PCs as well as business and various engineering servers, isolated from the automation systems only by an "internal" firewall. Also, the PBX server – which turned out to be a full-blown Microsoft Windows server – would sit on that same LAN and have a T3 circuit connection from the phone company to interface with the public telephone system.

But, in order to provide remote administration and management of the PBX and phone system, the vendor planned to separate part of that T3 bandwidth and have the phone company route it onto the Internet. This would allow the vendor to remotely manage and support the system (how convenient!) and establish a direct Internet connection pathway to all of the plant PCs and the plant-wide LAN, totally bypassing the carefully established "external" firewall that corporate IT had installed to isolate the plant's networks. (Oops!)

The problem was that the vendor and the plant personnel were dealing in mutual-mystification. The vendor just figured that the plant people understood how a modern digital PBX worked and the plant people just thought it was a cool new phone system with lots of fancy features. Fortunately, the problem was discovered in time to make changes to the plan and preserve the necessary electronic security perimeter.

In another plant, where an automation upgrade was planned, many of the plant personnel carried two-way radios even though many of these personnel also carried cell phones – you know, the ones that act like a walkie-talkie – and used them as often as they used the two-way radios – or frequently in place of those radios. The automation vendor in the project was trying to offer the plant the 'latest and greatest' technology as well as expanding their "$cope" of work as far as possible. As part of that offer, the vendor suggested establishing a WiFi "umbrella" over the plant site to allow for the use of wireless devices/instrumentation and for their in-plant communications. This would have entailed placing wireless WiFi repeaters and access points around the plant, connected to the plant LAN at various points.

The vendor promised to upgrade plant personnel with cell phones that could make use of the WiFi, eventually replacing the two-way radios. The plant personnel didn't immediately understand the security implications posed by cell phones that use the public cellular infrastructure versus those that seemed to work the same way, but actually make use of the private wired and wireless plant-wide networks. In particular, they didn't understand that the WiFi infrastructure would offer an attack portal into the plant networks, whereas the public cellular system did not. (Fortunately, the vendor did finally raise this point and offered to add various kinds of wireless security to plug the potential security breach – which I might remind you, they were implicitly going to create – in the electronic security perimeter!)

The third plant had a mix of security technologies. The plant's security systems – which were added after the plant was built – were a combination of analog and digital technologies. A Closed Circuit Television (CCTV) system connected by dedicated coaxial cables allowed remote monitoring of various entrance points and critical plant areas. And analog video tape recorders maintained a compressed recording of the camera inputs. A key-card access control system had also been installed, along with card readers and door controllers scattered around the plant and connected by serial communication links to a central configuration and monitoring computer.

The security vendor was proposing to upgrade the plant to use "WebCam" technology so that the existing plant-wide LAN could be used rather than running new,

separate cables. Moreover, that same LAN was going to be used to connect the replacement access control units and associated RFID tag readers and intrusion sensors. This, in turn, allowed all of the information to be routed to a plant security office, where PCs would be used to display and record the video and manage the access controls.

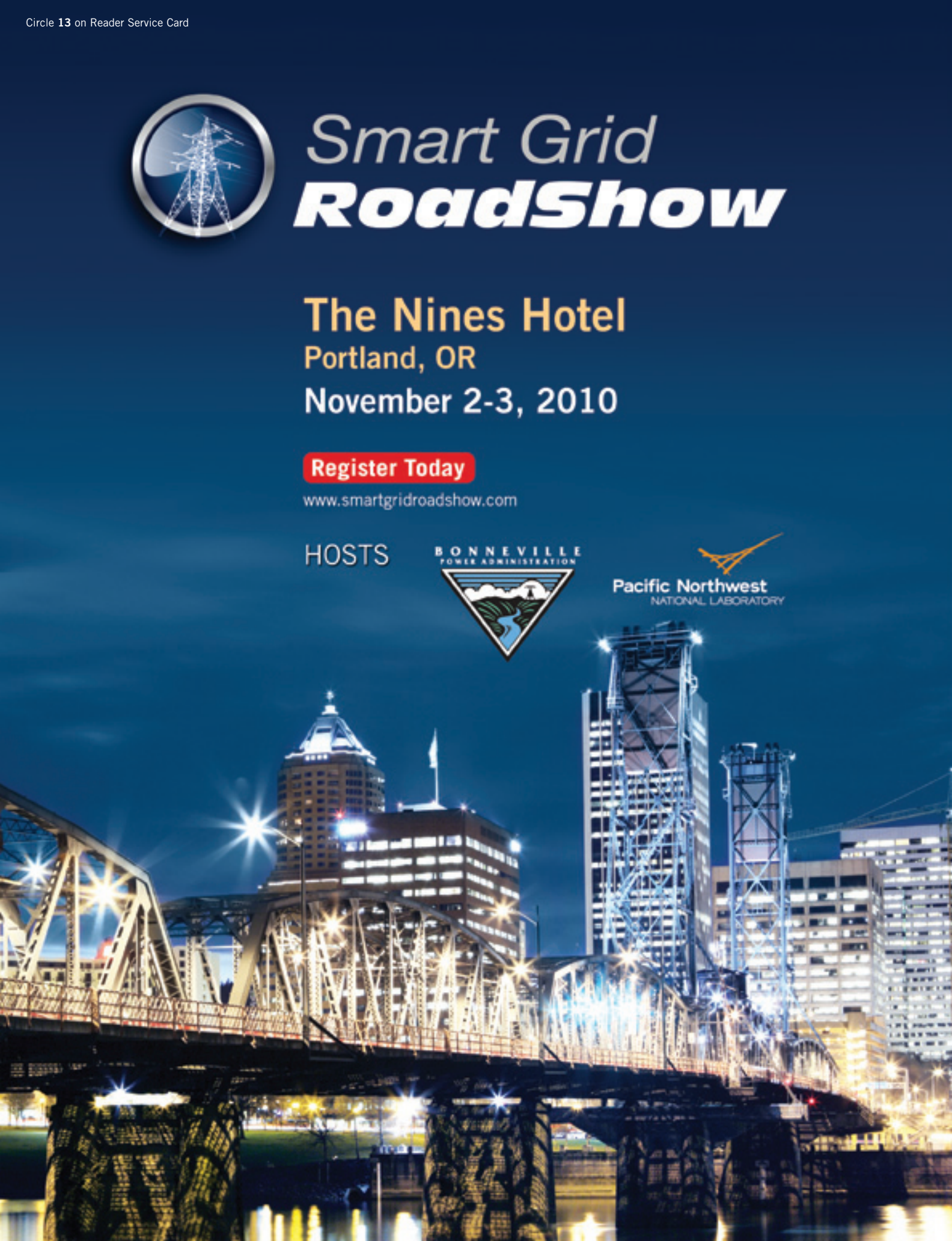
The server for the access control system was also going to be given a second Ethernet interface so that it could connect to the corporate WAN. Notably, this approach would allow their corporate HR department to remotely administer the access rights and personnel enrollment. Of course, this design also introduced unacceptable cyber vulnerabilities. For example, it created a 'bridge' between the plant LAN and the corporate WAN so that an attacker who penetrated the corporate network had an unprotected path onto the plant LAN that could potentially compromise or disable both the alarm/access control system and the video surveillance system. Again, this oversight was caught in time and corrected.

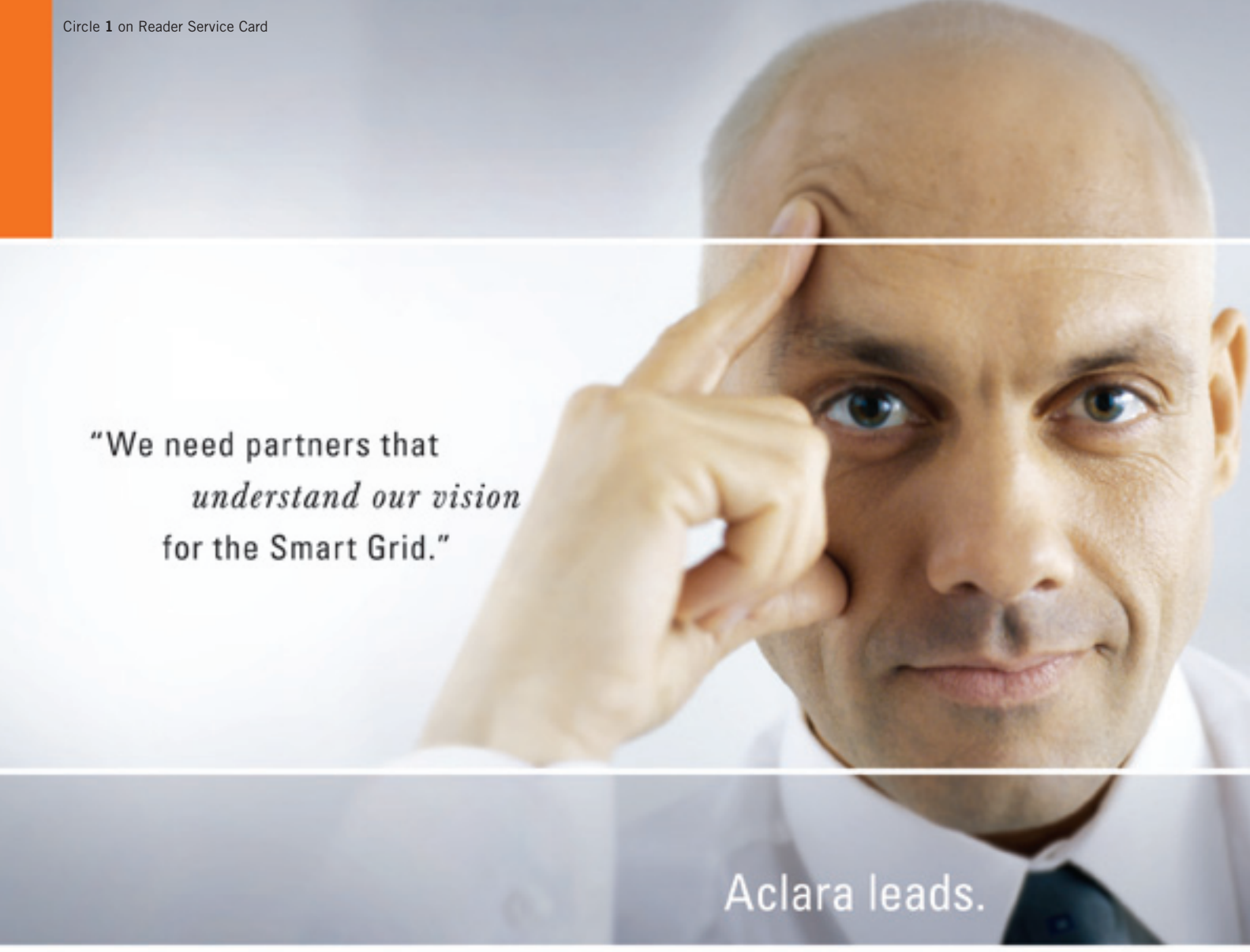
In all three of these examples it became obvious that the people involved, though perhaps well meaning and well intentioned, lacked a sufficiently current awareness of how the various technologies they planned to employ had converged and changed over time. Worse yet, they might have even been inadvertently aided by support from the corporate IT folks. In some cases, these IT personnel might not have had the requisite telecommunications expertise or experience with modern security systems technologies, but they would have been much more likely to have spotted the security issues.

The plant personnel – due to budget cuts and spending limits – were not being allowed to take continuing education courses or attend technical conferences; thus, their knowledge was outdated. This, more than anything else, contributed to the lack of awareness of the vulnerabilities they were poised to inadvertently introduce. Unfortunately, these are industry-wide issues and are not limited to just the three organizations used here as examples. There is certainly a case to be made for how some organizations are being "penny wise and pound foolish" when they skimp on continuing education of their engineering staff – but that will be the subject matter for a future session. – ***Tim***

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*.





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