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Electric Energy T&D MAGAZINE

MAY-JUNE 2012 Issue 3 • Volume 16

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Electric Energy Magazine is published 6 times a year by: Jaguar Media Inc.
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Terrebonne, QC Canada J6W 5S6
Tel.: 888.332.3749 • Fax: 888.243.4562
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Account #1899244

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GridLines

Michael A. Marullo,
Editor in chief

The 'Other' Smart Grid

As it turns out, there are actually TWO Smart Grids. The first is the one we all know about – the one where we force smart meters on everyone – and they really hate it and everything about it. The 'other' Smart Grid, however, has very little to do with smart meters and until recently was one of the best kept secrets around, except for the select few who realized early on that the first one was really an elaborate socialist-commie-pinko plot to control our lives through an electricity meter. (Clever, verrrry clever!)

More specifically, the 'other' Smart Grid I'm alluding to is the one where we actually modernize the grid and prepare ourselves for the challenges of the 21st century. Among other things, that will involve tackling issues like the fact that the average transformer in service today is 42 years old and we no longer have an extra one tucked away in the warehouse in the event of a failure. It also involves recognizing that it isn't just old transformers that we have to worry about, but also that a large portion of the grid infrastructure is nearing the end of its useful life, and we don't have the requisite funding to repair it – much less replace it!

Then there's also the human capital component of the 'other' Smart Grid. As we now know, the bulk of the current work force – the part that knows how all of the old grid works – has started retiring at the rate of about 1,000 workers a day for the next 20 years. Are you getting the picture here? Or, as the kids say these days, "*Do you feel me?*"

And that 'other' Smart Grid has so many dimensions to it that it's much harder for average people to understand. Therefore, it can't be neatly confined to a simplistic rollout of standardized widgets. Because it's so complicated, it doesn't usually get anywhere near the same level of recognition that the 'regular' Smart Grid gets either. It just isn't all that interesting for most folks, I guess.

But I think perhaps that's beginning to change. Recently there was a post on one of the online groups I belong to asking the question: *If Smart Grid is the solution, what is the problem?* This question evoked a number of really interesting responses, looking at various aspects of the issue from a wide-ranging spectrum of opinions and viewpoints. The one that really stopped me in my tracks, however, was a post from an engineer in India who said – and I've taken some license here to clarify and do a bit of paraphrasing, hopefully without changing the meaning of the original post…

"Smart grid is nothing but [the] modern grid. It has two components: One [is] IT, and the other is old style systems engineering, etc. Now, in the IT business, we are going to go to plug-and-play devices, and the rest is just as it was before. Do we need pubic voting for something that is technical and administrative? In India, we are close to plug-and-play devices for smart metering. We will probably build eight smart grid cities because we are not arguing about it. I think the biggest mistake has been to start a public debate on something that has always been there. True, the money has to be recovered, but then that is the cost of any improvements. [The] real problem is hijacking of this by IT companies, whereas really it is [a] power sector game!"

While you may not agree with all of it, I think the central point here is that in the industrialized world, we're busy arguing about the IT side of things and debating whether or not there will even be a Smart Grid.

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GridLines

Michael A. Marullo,
Editor in chief

Yet, the reality is that Smart Grid is fundamentally a power engineering issue and clearly something that must be done; it really isn't optional or even up for debate. Indeed, with or without smart meters, I'm sure we all want to continue having electricity to keep the lights on; heat and cool our homes and businesses; ensure that traffic lights are working 24-7; and retain all of the other beneficial dimensions of electricity that most of us take for granted. Whether the source generation comes from oil, gas, the sun, the wind, or a steaming pile of garbage, we still want that power to be there when we need it.

Let's not kid ourselves; the state of the grid today is a direct result of decades of deferred investment and deferred maintenance. The power grid has a lot of company in that respect. Over the past 50 years or so, we have been very democratic in our neglect of virtually every aspect of critical infrastructure: roads, bridges, telecommunications, railroads – even our educational institutions are straining under the burden of deferred infrastructure investments and deferred maintenance. All told, the price tag for fixing even the most critical of those deficiencies is in the trillions – yes, trillions (with a 'T') – of dollars.

Meanwhile, back at the Smart Grid we all know about, we've just spent (or will have spent very soon) several billion dollars on smart metering projects, funded primarily by the American Recovery and Reinvestment Act (ARRA), or the Stimulus Bill, if you prefer. When you add the required utility matching funds, you wind up in the neighborhood of $10-12 billion invested – again, mostly on smart meter projects. Sure, some other good things have been accomplished as well, but those projects are mostly in the minority when it comes to overall SGIG (Smart Grid Investment Grant) spending.

The good news is that the 'other' Smart Grid is finally starting to peek out from under the covers and get the recognition and attention it has always deserved. The bad news, however, is that the 'other' Smart Grid now needs an 'other' Smart Grid budget. Unfortunately, there isn't one – at least not yet. It seems like that might be something worth considering, don't you think? – ***Ed***.

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AEP and Great Plains Energy Form Competitive Transmission Company First projects to include 200 miles of 345-kV transmission in Missouri

Columbus, OH, April, 2012 - American Electric Power (NYSE: AEP) and Great Plains Energy (NYSE: GXP) have formed a new company to develop and invest in transmission. Through Transource Energy(SM) LLC (Transource), AEP and Great Plains Energy initially plan to pursue competitive transmission projects in the PJM Interconnection, Southwest Power Pool (SPP) and Midwest ISO (MISO) transmission regions. AEP owns 86.5 percent of Transource. Great Plains Energy owns 13.5 percent.

"Our nation and utility customers have benefited from the significant transmission investments made by AEP and other utilities decades ago, but it is critical that we move forward with substantial new transmission investment. Transmission infrastructure expansion is essential to ensure that the U.S. continues to have a reliable transmission grid to support both fundamental changes in how we generate electricity and future economic growth," said Nicholas K. Akins, AEP president and chief executive officer. "Order 1000, issued by the Federal Energy Regulatory Commission last year, creates new opportunities for competitive transmission investment by giving incumbent and non-incumbent transmission developers similar cost-recovery mechanisms for regional and interregional projects. Increased competition in the transmission space will foster cost-effective grid expansion for the benefit of customers."

"Our new venture will complement the transmission investments that AEP has been making through our existing transmission partnerships and state-level transmission companies, while giving us the flexibility to focus resources on the competitive transmission opportunities created by Order 1000," said Lisa Barton, executive vice president of AEP Transmission. "AEP continues to lead the industry in transmission design, engineering and construction innovation. Transmission infrastructure improves reliability, promotes access to renewable energy resources and enhances the efficiency of regional energy markets for the benefit of customers. Our experience and expertise put us in a unique position to provide creative, efficient transmission solutions that will help ensure future access to affordable and reliable electricity."

Great Plains Energy will seek regulatory approval to transfer two SPP-approved regional transmission projects, located in Missouri, to Transource. The Sibley-Nebraska City line is a 175-mile, 345-kilovolt (kV) line linking the Nebraska City substation (owned by Omaha Public Power District) near Nebraska City, Neb., with the Sibley substation near Sibley, Mo. Transource would construct and own approximately 170 miles of the project. Omaha Public Power District would construct the remainder of the transmission line. The project, estimated to cost approximately $380 million, has an anticipated in-service date of 2017.

The Iatan-Nashua line is a 30-mile, 345-kV line from the Iatan substation near Weston, Mo., to the Nashua substation near Smithville, Mo. The Iatan-Nashua project, estimated to cost approximately $54 million, has an anticipated in-service date of 2015.

Transource expects to file an application with the Missouri Public Service Commission this summer for line certificates granting authority to construct, own and operate the two SPP regional projects. Transource also intends to apply for a FERC formula rate for the Missouri projects later this year.

"These projects provide a foundation for the future growth of Transource. Great Plains Energy's strategic location between the SPP and MISO interface and its utility presence in Missouri and Kansas provide Transource with additional growth opportunities," Barton said.

Information about Transource can be found at *www.transourceenergy.com.*

Southline Transmission, Western Move Forward on Transmission Project

Lakewood, CO, April, 2012 - Western Area Power Administration and Southline Transmission, L.L.C., have signed an advanced funding agreement that will pay for Western staff support for the proposed Southline Transmission Project during its development phase.

The Southline Transmission Project would collect and deliver electricity across southern New Mexico and southern Arizona, relieving congestion, strengthening the existing electrical system and improving transmission access for local renewable and other energy sources.

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The project consists of two segments:

- One segment would be a new double circuit 345-kilovolt transmission line linking existing substations at Afton, south of Las Cruces, N.M., and Apache, south of Willcox, Ariz.
- The other segment would be an upgrade and rebuild of about 130 miles of existing transmission lines to provide increased capacity to transmit electricity between Apache and Saguaro substations, northwest of Tucson, Ariz.

Western Administrator Tim Meeks said, "We're pleased to be able to work with Southline during the development phase in a way that uses Western's expertise and is consistent with our principle that beneficiaries pay for Western's products and services."

"We look forward to a successful and collaborative relationship with Western as the Southline Transmission Project proceeds through the development process," said Hunter Hunt, President of Hunt Power, which is the parent company of Southline Transmission, LLC. "A fundamental premise of this project is to provide needed infrastructure in a way that minimizes impacts and maximizes benefits. Western's knowledge and experience will be critically important in developing a project that can achieve these goals."

Under the agreement, Southline will cover Western's costs related to National Environmental Policy Act compliance, Western Electricity Coordinating Council path rating, as well as Western's review and due diligence of the proposed project and development of interconnection agreements. The agreement will remain in effect throughout the proposed project's development period, after which it is anticipated that both Western and Southline will evaluate the project's progress and determine whether it should proceed to a request for Western's Transmission Infrastructure Program borrowing authority.

Western is serving as joint lead agency with the Bureau of Land Management in the preparation of the environmental impact statement for the proposed project.

EPRI Tests Confirm Viability of Using Drones to Assess Storm Damage on Distribution Systems
Technology Could Help Accelerate Outage Restoration

Palo Alto, CA, April, 2012 - The Electric Power Research Institute (EPRI) has completed tests determining that unmanned aircraft systems, or drones, can be used effectively to assess storm damage on utility distribution systems.

Conducted at the New Mexico State University Flight Test Center, the tests involved navigating several aircraft technologies and using high resolution video cameras to transmit images of power lines from a height of 5,000 to 7,000 feet. The tests determined that such images can be used by electric utilities to assess damage and pinpoint its location following a storm.

In the wake of a storm, damage assessment is frequently a choke point in power restoration due largely to obstacles, such as downed trees blocking roads or icy conditions that make it extremely difficult for utility crews to get to and report on distribution line damage.

"Our research clearly shows that drones may provide utilities a tool that could reduce outage restoration time," said Matthew Olearczyk, senior program manager for distribution research at EPRI.

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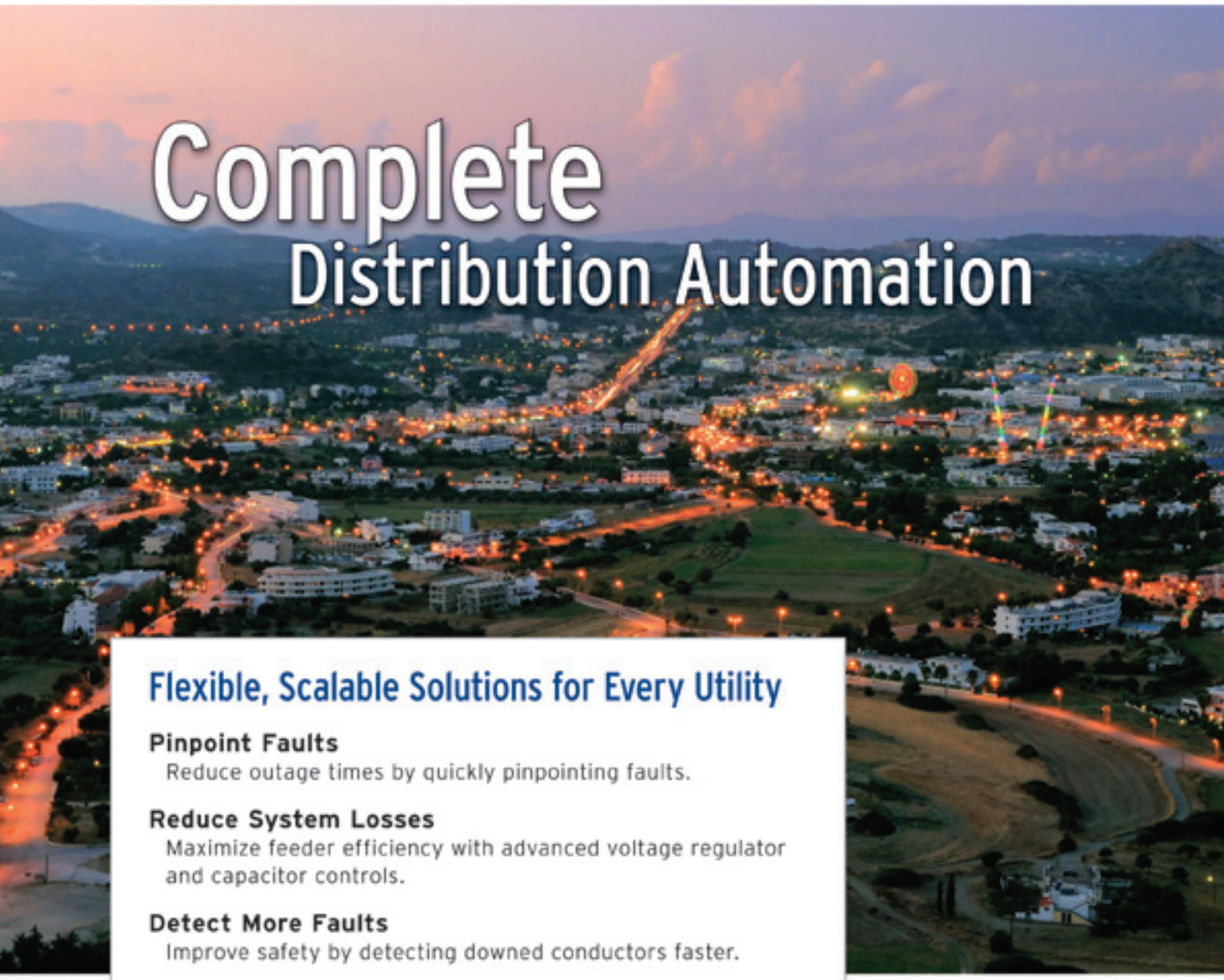

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"Using live steaming video information, utility system operators would be able to dramatically improve damage assessment."

With more accurate and timely information, system operators can better dispatch crews, establish repair priorities, and communicate more timely and accurate information to their customers.

Researchers assessed several drone technologies, looking at aircraft performance, control systems, and payloads.

The tests indicated that unmanned airborne technologies equipped with sensors, cameras and global positioning systems (GPS) could be deployed quickly, allowing utilities to evaluate large areas more quickly than ground-based crews, then develop a repair strategy and mobilize repair crews more quickly and effectively.

EPRI will also be evaluating drones and remote sensing technologies for inspection and assessment of overhead transmission lines. As part of this research, functional requirements will be identified for UAV inspection and market surveys will identify available UAV inspection technologies, services, and their costs.

Other industries such as oil and gas, forestry, and meteorology are evaluating or using unmanned air vehicle technology.

U.S. Energy Information Administration seeks input on proposed changes to two electric power surveys

Washington, DC, April, 2012 - The U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy, is proposing changes to two electric power survey forms. EIA is soliciting comments on the proposed changes in a Federal Register Notice.

The changes would reduce the number of power plants reporting fuel cost, quality, and receipts, and narrow the scope of data collected from smaller utilities on retail electricity sales and related data. The proposed changes would also reduce the workload for survey respondents and reduce EIA's costs for operating the surveys.

The changes would be effective starting in 2013.

The proposed changes to the fuel cost, quality, and receipts collection would eliminate from the survey all power plants with a capacity of less than 200 MW (the reporting threshold has been 50 MW), and limit the range of fuels collected to coal, petroleum coke, distillate and residual fuel oil, and natural gas. Minor fuels, such as blast furnace gas, kerosene, and jet fuel would be dropped from the survey.

These changes would not apply to the collection of data on power plant generation and fuel consumption. This information would continue to be collected for all power plants and fuels.

The proposed changes to the annual retail sales survey would direct the full survey to the largest 2,200 utilities, which account for about 98% of total U.S. electricity sales. About 1,100 smaller utilities (accounting for about 2% of annual electricity sales) would generally be required to complete only a short form each year. In addition to retail sales, other data affected by this change include information on demand response, distributed generation, and smart meters.

Comments on the proposed changes are due to EIA by May 14, 2012. For additional information see the EIA web site at *www.eia.gov/survey/changes/electricity*.

The product described in this press release was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analysis, and forecasts are independent of approval by any other officer or employee of the United States Government. The views in the product and press release therefore should not be construed as representing those of the Department of Energy or other Federal agencies.

Algonquin Power & Utilities Corp. provides update on Emera's increased ownership in the Company under the Strategic Investment Agreement Maine Public Utilities Commission indicates intent to approve Emera's continued investment in Algonquin

Oakville, ON, April, 2012 - Algonquin Power & Utilities Corp. ("APUC") (TSX: AQN) is pleased to announce that, following deliberations held on April 10, Maine Public Utilities Commission ("MPUC" or the "Commission") has indicated it intends to approve increased investment by Emera Inc. ("Emera") (TSX: EMA) in APUC under the APUC-EMA strategic investment agreement.

Under the terms of the expected decision, APUC anticipates in Q2 2012 to issue to Emera approximately 16 million shares in connection with subscription receipts previously issued to Emera for APUC's acquisition of Granite State and EnergyNorth and the 49.999% interest held by Emera in APUC's electric distribution utility in California. Further, under the 20% ownership threshold contemplated by the order, Emera would be approved to acquire approximately 10 million additional APUC shares. The Commission has left open for approval Emera's further investment of an additional 5 per cent in APUC through a future application to the MPUC.

"We are pleased by the deliberations today (April 10) as they allow us to complete the previously announced subscription receipts Emera has in APUC and provide comfort regarding the additional investment in APUC as we continue to execute on our growth strategy," stated Ian Robertson, Chief Executive Officer of APUC.

"We are very encouraged by the deliberations; this is good news for Emera," stated Chris Huskilson, Chief Executive Officer of Emera. "Our relationship with Algonquin is strong and we remain committed to further investment as contemplated in the Strategic Investment Agreement."

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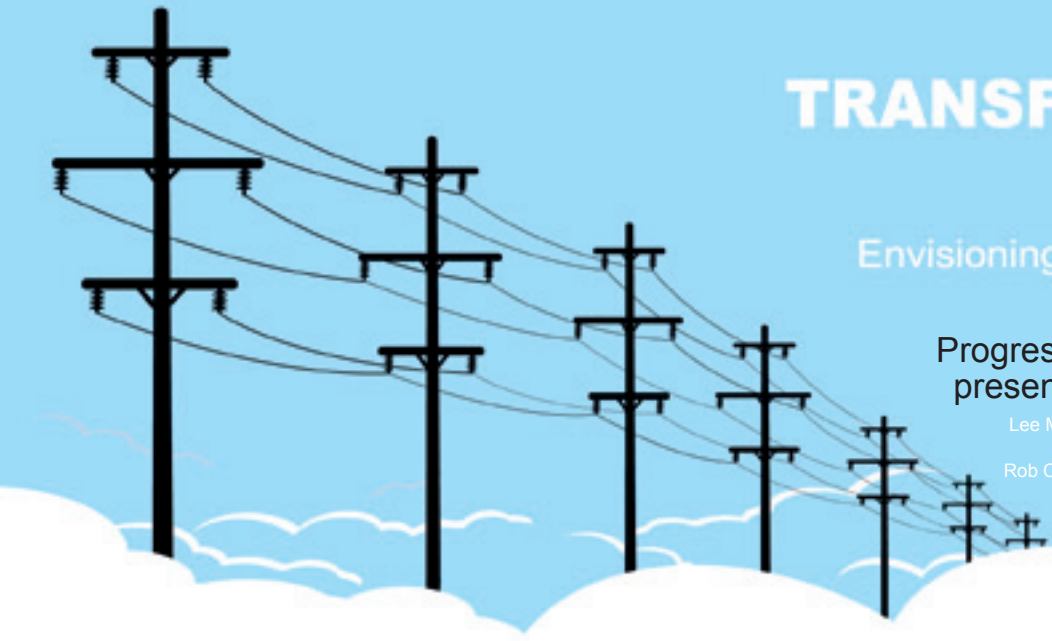

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Lee Mazzocchi, Vice President & Chief Procurement Officer (Progress Energy)
Rob Caldwell, Vice President, Efficiency & Innovative Technology (Progress Energy)
Michael Lewis, Senior Vice President, Energy Delivery (Progress Energy Florida)

EET&D: When we talk about Smart Grid, what does it mean to Progress Energy?

Mazzocchi: Smart Grid is a term used to describe a modernized electric transmission and distribution system – utilizing digital technology – that provides advanced information about the status of the transmission and distribution system and customer energy use. Progress Energy is primarily taking a grid-first approach to our Smart Grid investments, to enable the grid to become more efficient and support future potential customer-facing programs. This grid modernization effort involves significant upgrades to our existing infrastructure and strategic investments in two-way communications technology.

EET&D: How do these investments change the way Progress Energy delivers electricity?

Mazzocchi: Well, for one, it will create new efficiencies in the way we deliver electricity, which means we can help optimize our existing generation capacity during periods of peak customer demand. The advanced communications technologies we are building into the grid will also provide us with real-time information on the health of our system, enabling us to better meet our customers' expectation of reliable service every day.

In the years ahead, we expect that our customers will increasingly look to the modern grid to provide even more functionality to meet their needs. So we fully expect that the way we deliver electricity – our work force and our processes – will continue to evolve as we seek to provide new value to our customers.

EET&D: The transition to a smarter grid doesn't come without a lot of change for the utility. How are you effectively managing the changes this new technology will bring?

Lewis: The utility industry, as a whole, is currently experiencing transformational changes, of which Smart Grid is just one part. New policies at the state and federal levels, the need for fleet modernization and technological advancements all have impacts on the way we do business.

At the operational level, new technologies and programs will require significant changes in process for our company. We recognize that the evolution of process doesn't happen overnight. We are leveraging established change management practices to help employees transition to new systems and processes.

EET&D: How important is change management to this transition?

Lewis: It is very important. Utilities must make change management and process optimization a core part of their Smart Grid deployment early in the process to be successful. This is also important at the industry level. As each utility takes a different path on their Smart Grid journey, standardization will become an important challenge and opportunity for us all in the years ahead.

EET&D: Tell us more about Progress Energy's grid modernization initiatives and what they may mean for the customer.

Caldwell: Sure. As was mentioned already, we are focusing our investments primarily on the grid side. These investments include installing advanced communications and load management technologies on our distribution grid to make the system operate more efficiently, especially during periods of peak demand. We're also installing technologies to isolate outages faster and monitor the health of assets on our system, which will improve service quality and reliability for our customers. And we are enhancing our electric system to support emerging technologies such as renewable energy and electric vehicles, as well as customer-facing programs that a smarter grid can make possible.

EET&D: So how will these initiatives be financed?

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Caldwell: Progress Energy is investing more than $500 million in its EnergyWise® Smart Grid initiatives. The company is proud to have been one of only six utilities in the nation to receive a $200 million U.S. Department of Energy grant for Smart Grid projects. Our total Smart Grid investment includes more than $300 million in company matching funds, which will help to support projects in the Carolinas and Florida. The long-term result will be improved efficiency, quality and reliability for our customers and communities all across our service territories.

EET&D: As you deploy this technology within the utility, what are some of the challenges you are facing?

Lewis: Many of the challenges we are facing are the same as those being experienced across the industry. These challenges include preserving customer privacy and data integrity, addressing potential threats to cyber-security, anticipating impacts to reliability and grid management, responding to regulatory requirements and navigating political change. As with the introduction of any new technology, developing and implementing new processes will present additional challenges.

EET&D: You call your Smart Grid program "EnergyWise." Why did you feel the need to brand your grid modernization activities?

Caldwell: Branding our initiative was about more than a catchy name or a marketing gimmick. When we talk about Smart Grid at the national level, the discussion often goes directly to the customer side – in particular, smart meters. And for many utilities, that approach makes sense. But Progress Energy took a different, and, we believe, very unique approach to modernizing our grid. Our initiatives are helping the company and our customers use energy wisely. Because of that, we felt that building our own identity for these investments was important.

Mazzocchi: I think Rob's comment makes an important point. Each utility approaches Smart Grid a little differently. Our program evolution was driven by a number of factors, including the effects of existing and future regulation on our business, customer needs in our various markets, where we are operationally as a utility in each state that we serve, the business case for the investment and our risk assessment and recovery model for those investments. Each business case is different, making each utility's grid modernization path different as well.

Lewis: The diversity of Smart Grid programs across the country also means that we have a lot we can learn from each other. We see that even within our company. In Florida, we are building on our existing direct load control successes. In the Carolinas, they are building on a different set of successes. But, in the end, we will share those strengths across our two utilities and move forward together. The same opportunities can exist across the industry. There isn't a one-size-fits-all solution to Smart Grid.

EET&D: How will your proposed merger with Duke Energy change your approach to Smart Grid?

Mazzocchi: Each of our companies approaches Smart Grid investments a little differently, and those differences are largely due to the different business situations and regulatory environments in which we operate. But, as companies, we are much more alike than different. And just as we currently apply lessons learned between Progress Energy's two utilities, we will have opportunities to combine the best practices of both companies to build a stronger Smart Grid vision for the future.

EET&D: I want to thank all of you for taking time out of your busy schedules to share this information with our readers and for being so forthcoming with details about your plans and programs. Best of luck to all of you as you continue along your strategic roadmap to creating an ever-smarter grid!

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GREEN OVATIONS

Innovations in Green Technologies

Prepay Energy's Pathway to Consumer Satisfaction and Benefits

By Cindy Boland O'Dwyer, Vice President, DEFG LLC

EcoAlign is a strategic marketing agency focused on energy and the environment. DEFG LLC is a specialized management consulting firm in the energy space. In November 2011, the two firms partnered to conduct approximately 900 online interviews to test customer awareness and acceptance of prepay electricity offerings in Texas and Arizona,[1] the two states with the largest base of U.S. consumers currently on a prepay electricity plan. The EcoAlign-DEFG team worked with the members of the Prepay Energy Working Group[2] to finalize the survey instrument, and research for the survey was conducted by Russell Research.

DEFG's Prepay Energy Working Group – now in its third consecutive year – has researched trends and levels of consumer satisfaction across different prepay industries. In late 2010, a national consumer survey was conducted to test perceptions and expectations related to a variety of prepay services and products, and to examine the potential for voluntary prepay electricity options offered by local utilities.[3]

One objective of the latest survey conducted in Texas and Arizona was to revisit trends and levels of consumer satisfaction across different prepay industries. Even more important, however, was an effort to gain insight around consumer awareness and acceptance of prepay electricity service. Survey questions explored actual or perceived benefits, concerns and expectations tied to prepay electricity.

Survey Findings

The 2010 national survey revealed prepay as an option for a variety of products and services that had in fact become mainstream. Americans were increasingly using prepay in many forms, such as reloadable debit cards, transit cards, healthcare, wireless service plans, etc., and they were satisfied. Moreover, once consumers used a form of prepay, they were likely to continue using it, to try it for other services/products, and to recommend it to family and friends. The survey discovered "ease" and "convenience" to be the drivers behind customer satisfaction with various prepay options.

The latest results from Texas and Arizona point to consumers strongly correlating prepay electricity with increased control and management, and the potential to use less energy and save money. Nearly all U.S. energy consumers currently receive an energy bill at the end of the month with no real or temporal linkage between consumptive behavior and cost. Prepay electricity enabled by smart grid is a billing option with the potential for a consistent feedback loop delivered via SMS, email, web, in-home display, or possibly a combination of these channels.

The consistent information flow provides consumers the opportunity to monitor their usage and credit balance, thus linking dollars and energy usage in close-to-real-time. Prepay service providers have in fact realized an energy consumption impact, with Salt River Project in Arizona reporting an average decrease in usage of 12 percent per household.[4]

While still a nascent offering in most U.S. jurisdictions, prepay electricity shows promise for high satisfaction among the consumers that choose it. The top line findings include:

- The top reasons consumers would enroll in a prepay electric service plan are: "control over energy costs and budget" (46 percent), "prefer to pay for energy as you use it" (37 percent), and "want to reduce energy use and monitor closely" (32 percent)

Total Respondents	Total (880) %	State: Texas (470) %	State: Arizona (414) %	Gender: Male (442) %	Gender: Female (450) %	Home Ownership: Own Home (490) %	Home Ownership: Rent Home (313) %
You want control over energy costs and budget	46	46	45	42	49	45	48
You prefer to pay for energy as you use it	37	38	36	37	37	39	33
You want to reduce energy use and monitor closely	32	29	35	32	32	31	28
You don't want to pay a security deposit to open up an account and/or avoid other fees	25	27	23	24	26	23	28
You do not want a monthly bill	22	17	27	24	19	18	27
You want to go paperless and save a stamp	11	12	9	13	9	13	8
You want more feedback/advice from your utility to manage your bills	11	10	12	12	10	13	10
You want to help pay/manage a family member's account, e.g., student at college or elderly parent	10	12	8	9	12	11	11
You have a seasonal home and prepaid provides greater flexibility	7	8	5	7	7	6	8

Top Two Reasons Would Choose or Have Chosen to Enroll in Prepay Electric Service Plan [5]

[1] *Prepay electricity service, or a "pay-as-you-go" option offered by a utility or energy supplier, would be voluntary and require the customer to prepay or pay upfront for electricity before using the service.*

[2] *The Prepay Energy Working Group is managed by DEFG LLC and consists of market participants (utilities, energy retailers, metering and software vendors) and a pro-bono advisory panel of regulators and consumer advocates. Member interacts on a regular basis, and all research efforts and deliverables are put through an iterative process and thoughtful discussion prior to public release.*

[3] *The results and key findings from the national survey were shared in EcoPinion Survey Report No. 9, "Is Prepay the Way? Consumer Perceptions of Prepay in the Utility Sector."*

[4] *Paying Upfront: A Review of Salt River Project's M-Power Prepaid Program. EPRI, Palo Alto, CA: 2010. 1020260.*

[5] *Question 10: Which of the following are the top two reasons that you and your family would choose or have chosen to enroll in a prepaid electric service plan?*

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- Consumers think the most important features of a prepay electric service plan are: "using less energy and saving money" (33 percent), "avoiding fees" (25 percent) and "helps manage my budget better" (24 percent)

- When asked for one word to describe prepay electric service, "convenient" was mentioned the most by far. Other terms mentioned at lower levels were: "interesting," "easy" and "savings"

Provide One Word To Describe "Prepaid Electric Service [6]

- When asked for one word to describe the biggest concern regarding prepay electric service, the most frequently-mentioned were: "cost," "price," "overpaying" and "expensive." At slightly lower levels, consumers mentioned: "money," "unknown," "reliability," "running out," "usage" and "budget"

- When asked to rate their concerns using a ten-point scale, consumers applied a "9" or "10" (representing extreme concern) to the following: "service disconnect/electricity going off when my prepay account balance runs out" (53 percent); "price/higher rates" (48 percent); "fees associated with prepay" (43 percent); "expiration of credits over time" (37 percent); and "knowledge/awareness of my account status" (35 percent).

	Total	State		Gender		Home Ownership	
Total Respondents	(890)	Texas (476)	Arizona (414)	Male (440)	Female (450)	Own Home (490)	Rent Home (313)
	%	%	%	%	%	%	%
Service disconnection/electricity going off when my prepaid account balance runs out	53	54	51	47	58	55	51
Price/higher rates	48	47	48	43	53	47	48
Fees associated with prepay	43	41	46	37	50	43	44
Expiration of the credits over time	37	36	39	34	40	37	37
Knowledge/awareness of my account status	35	35	34	29	40	32	38
Security	31	32	30	29	33	30	35
Privacy	30	32	28	28	33	31	28
Consumer protection	30	32	27	26	33	29	32
Making payments	26	26	27	21	34	24	32

Specific Concern regarding Prepaid Electricity Service (applied a "9" or "10" which represents extreme concern to the following) [7]

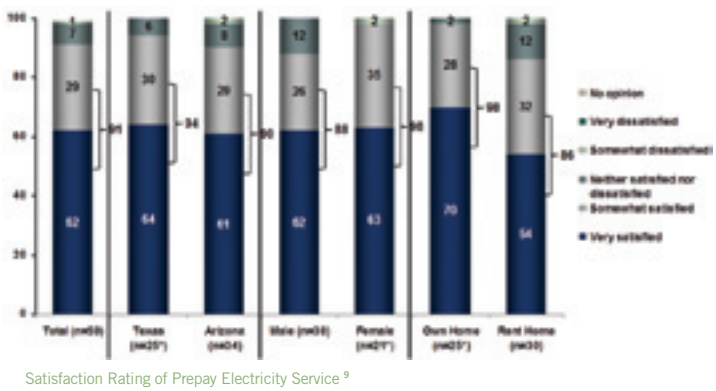
- One half of the respondents do not know whether prepay or post-pay energy costs more, and one fifth think prepay energy is more expensive

- When the respondents were asked what types of consumers may benefit from a prepay electric option, 18 percent thought it was best suited for low-income consumers, but 27 percent thought it would benefit all the consumer segments that were listed (i.e., renters, seniors on a fixed income, young people 18–30 years old, among others)

- As noted earlier, Texas and Arizona were chosen as the focus of this consumer survey because they are the states with the greatest number of consumers currently on a prepay electricity plan. Responses reveal both states to still be in the early stages of adoption, with 7 percent of respondents in Texas and 10 percent in Arizona indicating they currently receive prepay electricity service [8]

Admittedly a small base of respondents, but nearly all of the current prepay customers are satisfied with their current prepay electric service:

- More than half (62 percent) indicated being "very satisfied," while an additional 29 percent are "somewhat satisfied" (totaling 91 percent)
- When asked if they were likely to recommend prepay electric service to family and friends, 63 percent are "very likely" to recommend, while additional 25 percent are "somewhat likely" (totaling 88 percent)
- These numbers are nearly identical



Satisfaction Rating of Prepay Electricity Service [9]

[6] *Question 16: What one word would you use to describe prepaid electric service? Please be as specific as possible.*
[7] *Question 18: When considering prepaid electric service, how concerned would you say you are when thinking about each of the following? Please use a scale from 1 to 10, with 10 being Extremely Concerned and 1 being Not Concerned At All.*
[8] *The total number of consumers enrolled in a prepay electric plan in Texas and Arizona is currently in the hundreds of thousands, which is still substantial and also ripe for growth.*
[9] *Question 6: How would you generally rate your satisfaction with your prepaid electricity service? (Caution, small base size: total currently enrolled in prepaid electricity plan.)*

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What Does It All Mean?

The findings show that the trend towards prepay products and services continues to intensify, with approximately two thirds of consumers in Texas and Arizona having used some type of prepay method in the recent past, in particular reloadable debit cards, gift cards, and/or wireless services. Prepay as a bill payment option or alternative means to transact business is clearly used and accepted by a majority of Americans regardless of income.

What is behind the trend? Why are consumers satisfied with prepay options? Leading drivers for customer satisfaction with various prepay products and services are convenience and ease. Similarly, the perceived attributes of prepay electric service and top reasons to sign up for prepay electric service in both the 2010 survey and the latest survey were convenience and control over costs and energy usage. These drivers are directly related to lifestyle, budget and bill payment preferences.

Consumer segments that will be interested in prepay service will have different sets of motivations and expectations. The ability to pay for electricity in any amount (small or large increments) at a selected time via a preferred channel (e.g., mobile, online, or pay center at a local supermarket) will be valued by a certain segment of customers over a one-time lump sum monthly bill.

Perhaps more affluent "snowbirds" might like the ability to pay in advance for several months and receive regular updates with usage data for a home they left vacant, or possibly even "self disconnect" (i.e., purposely allow credit to run to zero, prompting a disconnect) for an extended period without the hassle of late payment penalties and the reconnect process typical for post-pay service.

An interesting finding is the potential willingness of 88 percent of current prepay electric consumers to recommend the service to their families and friends. While an admittedly small sample, the finding indicates high satisfaction and also points to these customers having trust in the potential for benefits to be shared by a certain segment of their family and friends network. This impact can be employed as a customer satisfaction metric referred to as "net promoter score," which over the last few years has garnered greater significance with increased communication via mobile lifestyles and social media.

Prepay electricity is a voluntary option that will be preferred and valued by certain segments of customers, but not by others. An offering such as prepay electricity – and other options enabled by smart grid – mandates a more nuanced, segmented view of the marketplace that goes well beyond the "ratepayer" construct where everyone is treated the same regardless of personal preferences.

Recommendations

With a line of sight to customer satisfaction and benefits for certain segments of consumers that will opt for prepay electric service, the DEFG-EcoAlign team makes the following recommendations:

- **Research:** There is a need for more research to identify and better understand the segments of customers that are going to like prepay electricity, and the different motivations and expectations for each segment.

- **Satisfaction and Benefits:** Perceived benefits of prepay electricity include: using less energy and saving money, increased budget control, convenience, no security deposit and late fees, and no monthly bill. Indeed, prepay can meet expectations around improved cash management in a number of ways. For instance, the nature of prepay is incremental compared to traditional monthly billing. As more consumers, especially younger adults, increasingly conduct financial transactions via smart phone, there is an opportunity for consumers to make payments wherever, whenever, and in an amount that best suits them. More frequent payments in smaller amounts align nicely with a mobile lifestyle.

- **Messaging:** With different segments identified, a provider can market to customers in a manner (via preferred communication channel) and with content that aligns with their motivations and expectations (e.g., explain why prepay provides additional budget control).

- **Education:** Prepay electricity is a bill pay option, but also a very different way of buying and using electricity that changes the relationship between the provider and the customer. Education on how prepay works is important. Over time, with substantial analysis and data of actual use, consumers would appreciate predictive recommendations to help them optimize their use of the service.

- **Transparency:** There is real uncertainty regarding the price of prepay electric service and concern regarding the possibility of service disconnect / electricity being turned off. Service providers must be transparent to dispel confusion—the basis for pricing and the applicable policies and protections for service disconnection must be clearly addressed.

- **Potential for Energy Management and Pricing Options:** Results point to consumers making a strong correlation between prepay electric service and using less energy and saving money. Prepay should be viewed as a platform for energy management and other pricing options.

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Prepay could be viewed as a daily bill pay conservation that is transactional (dollars and cents), relevant (focused on saving energy to manage bills), and actionable (today's information could result in impacts on tomorrow's conversation). As part of the conservation, consumers would be open to receiving relevant and actionable information such as rebate details, different pricing options and energy assistance.

The facts show real potential for a substantial consumer base to use and value prepay electric service. Prepay service, however, is often framed as a low-income option within the utility sector. As many low-income consumers value the option to better manage their cash/credit, so too would other consumer segments. The key is to identify them.

About the Author

Cindy Boland O'Dwyer is a Vice President with DEFG LLC, a specialized management consulting firm in the energy sector, and a lawyer with LEED G.A. Certification, the U.S. Green Building Council's Leadership in Energy and Environmental Design Green Associate designation. Ms. O'Dwyer leads DEFG's Prepay Energy Working Group and activities in legal and regulatory matters.

PREPAID ELECTRICITY POWERS A SHIFT IN CONSUMER BEHAVIOR

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"Direct Energy's prepaid service is designed to give people control over their electricity bills," said Jim Steffes, vice president and general manager for Direct Energy. "With quick, easy access to their energy usage information, customers can take some easy steps to reduce costs by reducing usage."

As customers are becoming more aware of their daily usage, they are better able to manage their energy bill. "My prepaid electricity has been running $25 to $30 a month, whereas my bill used to be somewhere between $100 and $180," said Marilyn, a prepaid customer.

Not only does prepaid provide cost savings to customers, but it encourages customers to be more conscious of the environmental impact of those changes– last summer prepaid customers used 14% less peak energy. This proves that prepaid electricity is not just a new way to pay for electricity; it's a fundamental shift in the customer experience around electricity consumption.

Direct Energy was the first of the three largest retail electric providers in Texas to offer consumers the choice of a hassle-free way to pay for their electricity, as and when they need it. Consumers now can be in control – simply by paying for what they use and the flexibility to pay for more electricity when it meets their needs.

"With pay-as-you-go, you know each day what you spend. You can remember what you did yesterday versus what you did a month ago," said Tonie a prepaid customer. "I love the program. I've recommended it to my father, two of my coworkers and my best friend." This level of consumer interest helps to explain how prepaid has achieved a 16 percent monthly compounded growth rate in 2011.

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Integration Meets Main Street: City of Glendale Takes on the Smart Grid Challenge

By Edward Fraga, Director of Information Services, City of Glendale Water & Power
John O. Wambaugh, Senior Vice President and Joe Tellez, VP of Smart Grid Integration Consulting, UISOL

Municipal utilities – or 'Munis' as they are often called – are the hometown power provider for more than two thousand communities across America. They are the personal face of energy to the 46 million people to whom they deliver not only electricity but often the gas, clean water, and wastewater infrastructure – the very underpinnings for public safety and economic prosperity for entire regions. As community-owned resources, MUNI interests are closely tied to the consumers they serve. Today, and over the next two decades as utilities update aging infrastructure with Smart Grid applications, municipal utilities face uniquely complex integration challenges and opportunities.

The Muni Smart Grid Premise

When a municipal utility deploys advanced metering infrastructure (AMI), adds two-way communications devices to its T&D resources, or incorporates renewable resources onto its power grid, it is likely to generate exponentially greater volumes of data. Likewise, every Smart Grid application tends to trigger new needs for managing and sharing information. Smart grid innovations bring complexity to any type of utility, but particularly for munis. For the muni –– often tasked with providing multiple services to diverse users across a community with a generally small in-house staff -- the resulting architectural complexity can be tremendous.

However, the potential gains for munis are great, too. Municipal utilities may be smaller in size and capability than their larger IOU counter parts, but they often also have relatively short infrastructure deployment cycles; small, lean IT departments; and more extensive application of standards. Municipalities are well placed to unlock additional opportunities by leveraging their technology investments across their communities. For example, munis have greater opportunities to integrate city-wide services which historically may have resided in departmental silos. In fact, munis, by the very nature of their mission and role in their communities, may be better positioned than any other utility type to readily enable the truly integrated "Smart City."

Glendale's Smart Grid Vision

From a national perspective, Glendale Water and Power (GWP) is a medium-sized municipal utility. It is owned and operated by the City of Glendale, the third largest municipality in Los Angeles County, which provides municipal utility and public works services to 200,000 residents. GWP manages a service territory with 71,000 residential and 12,000 commercial and industrial electric customers. GWP also manages about 29,000 residential and 4,000 commercial and industrial water customers.

The City of Glendale was the first ARRA Smart Grid Investment Grant (SGIG) recipient in the nation to sign a contract with the Department of Energy and is currently implementing Smart Grid technology and business processes to transform utility operational efficiency and sustain strong customer satisfaction. GWP recently completed the implementation of a new Advanced Metering Infrastructure (AMI) project as well as beginning to implement new distribution monitoring and control systems for power and water. These implementations represent enterprise data management systems that will significantly enhance Glendale's capability to interact with its water and power customers.

Smart City Starting Point

Glendale's technology started in a position that is common among municipalities. Originally, the structure was one of departmental silos and manual processes. Basic utility operations were achieved through applications that were not integrated to support process automation. Employees had little access to information from other operational areas. The infrastructure and application portfolio was managed by the individual departmental organizations with little city-wide consistency or standardization. Overall, GWP's operational systems were both deployed and managed outside of the centralized city IT department. The following diagram depicts the architectural starting point for Glendale's path to Smart Grid integration. City enterprise back-office systems (on the right) were isolated both physically and logically from the operational systems (on the left).

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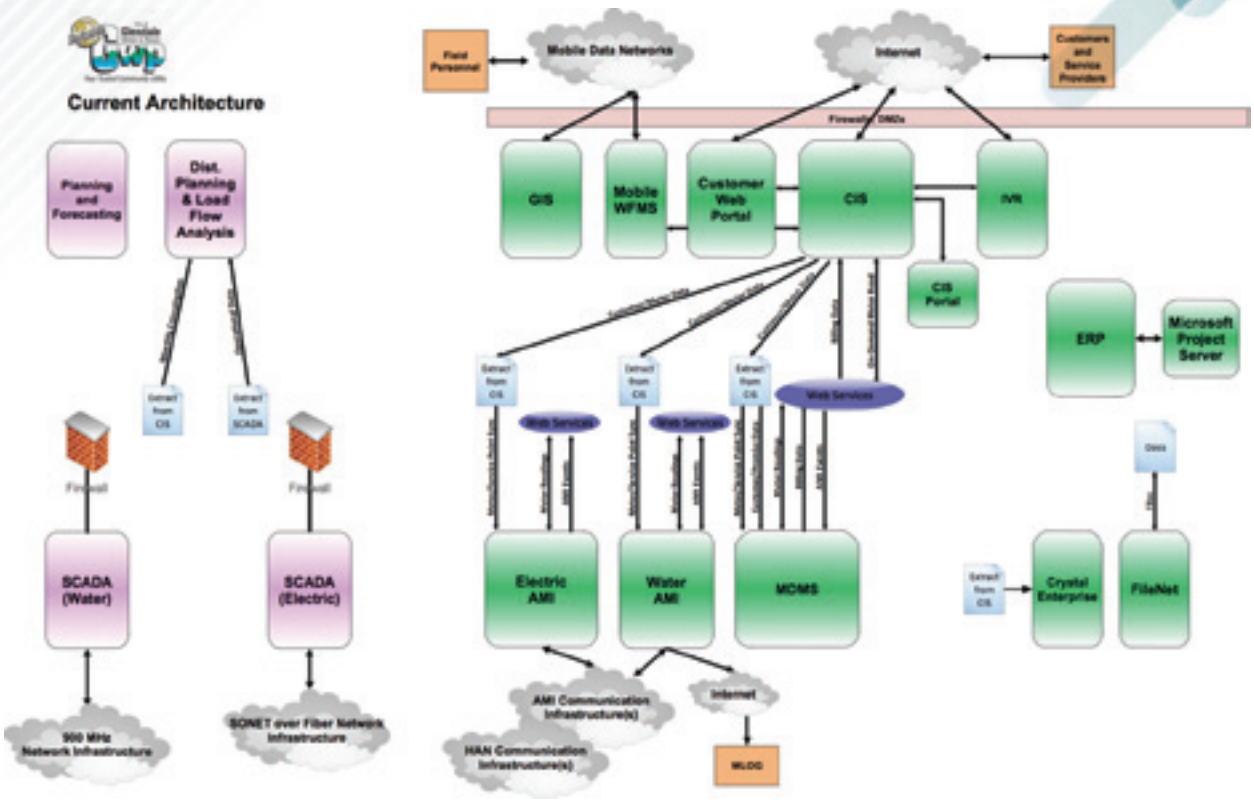

Integration Comes to Main Street

Depicting existing architecture is an essential step toward Smart Grid integration. It helps ensure that all city services are included in the overall effort. Early in the Smart Grid movement, the application of architecture as a discipline to systems integration was considered something only larger organizations with sizeable IT resources could consider. However, advances in data standards and systems integration platforms can now provide municipal utilities with a solid foundation upon which to integrate Smart Grid applications in a more effective and efficient manner than ever before. To achieve this vision, a municipal utility's management must maintain an open view and willingness to consider alternative approaches. Fortunately, these qualities tend to be found readily in the smaller, more collaborative municipal enterprises.

As at many munis, staff in GWP's operational departments felt the city's IT department lacked the level of understanding and responsiveness needed to address the mission critical support needs of real-time operational systems that manage the electric and water distribution network. This perception drove operational departments to provide their own applications support outside of the city IT control. This siloed IT/OT arrangement is common throughout the utility industry and, historically, was considered adequate. However, the need to replace, upgrade, implement and integrate smarter utility applications requires the sharing of data across silos. It needs highly integrated systems that go beyond the basic support capabilities of the operational areas.

As each department began to orient itself around Smart Grid and began defining information system projects, city IT staff quickly realized that the overall program and infusion of SGIG funds meant that they would need to implement or enhance at least ten new enterprise-class utility applications. These applications would include:

- automated metering,
- outage and distribution management,
- workforce and asset management, and
- demand response.

In addition, it would require building more than 60 new interfaces between these new systems and existing legacy applications within a five-year window.

This program is a tall order even for the more capable and disciplined IOU's, so how could it be implemented through the practices of the past and without a systematic approach to architecture? Would it require an army of IT resources and systems integrators that would quickly overwhelm both the internal staff and program budget? Was there, perhaps, a more tactful model that leveraged the existing organization and provided augmentation to key critical skill set areas?

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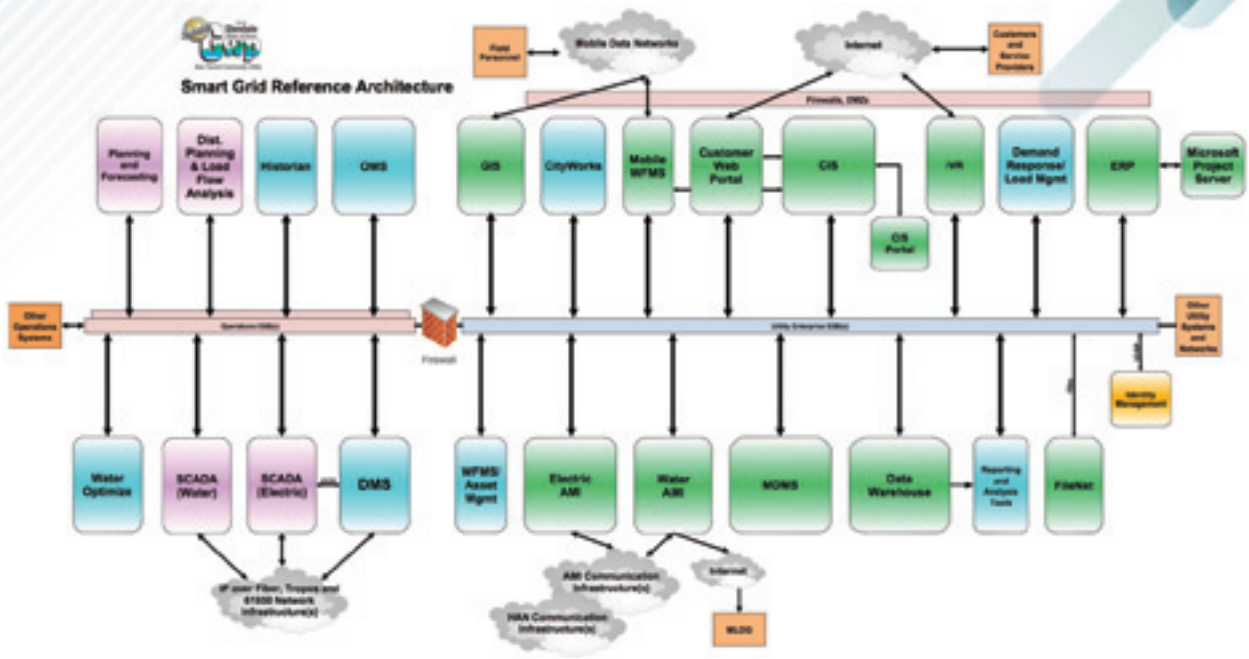

Framework for a Smarter City

Although the primary source of funding for the program is the SGIG, budget approval processes needed to still flow through the city council. This requirement soon brought the IT department, a team that needed to understand complex information technology investments in order to appropriate funds, to the forefront of city management. Not only did this move present a set of challenges to the IT department to convey how such investments are needed in support of Smart Grid, but it also required the explanation of why the benefits of enterprise architecture and having a standard approach to application integration are foundational elements for a 'Smart City' framework with city-wide benefits potential. Although the new IT 'assets' are primarily for the operational departments, they essentially become shared, enterprise-wide utilities that present additional cost allocation challenges to ensure that the operations side is only funding its fair share.

GWP General Manager Glenn Steiger and City of Glendale IT Director Ed Fraga, both recognized the need for a comprehensive technical roadmap for the future integration of Smart Grid systems. They committed to mutual cooperation between the city and operations to ensure that the new technology investments would work together to provide city-wide benefits. They envisioned a roadmap to reflect the technology principle of implementing best-of-breed commercial, off-the-shelf software (COTS) and integrating standards rather than attempting to build custom application solutions. The principle of 'buy and integrate' vs. 'develop and customize' is much better suited for Glendale given the availability of technical resources on staff and the desired timeframe to implement the new systems. Accordingly, they decided to develop an architectural roadmap to achieve their objectives.

This roadmap, known as the GWP Smart Grid Architecture, is an overall guide for the acquisition and implementation of all systems and integrations. It is designed to ensure Glendale has a consistent, secure and reliable set of technologies and interactions. The advancements will make information available when and how it is needed by GWP operational and city enterprise systems, employees, customers and stakeholders. Both water and electric departments participated in developing the architecture as did City central IT to ensure that the architecture would bridge the current state of processes and systems to the future state of the integrated utility. The resulting architecture reflects both the business and technical needs of operations and the city by incorporating a broad set of requirements and addressing critical gaps in the current state.

The Enterprise Service Bus

Glendale's Smart Grid architecture, in support of the Smart Grid and city-wide business strategy, is composed of four architectural domains - data, applications, infrastructure and security - and describes state-of-the-art technologies, processes, policies and standards. The Smart Grid Reference Solution Architecture, shown in the figure below, is a fully-integrated set of applications utilizing an Enterprise Service Bus (ESB) as a common integration platform foundational to the architecture.

ESB software connects applications and users via a set of standards and provides the interoperability that is essential to support and simplify complex application integrations. ESB software is vital to the integration architecture of GWP, which is based on a utility common information model standard data model, web services and a service-oriented architecture. The integration platform will be used to facilitate the exchange of information across various GWP operational and city enterprise applications; enabling more complex system, data and business process integration among a variety of legacy and new Smart Grid applications.

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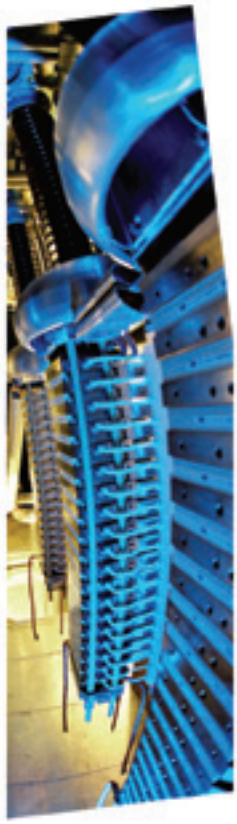

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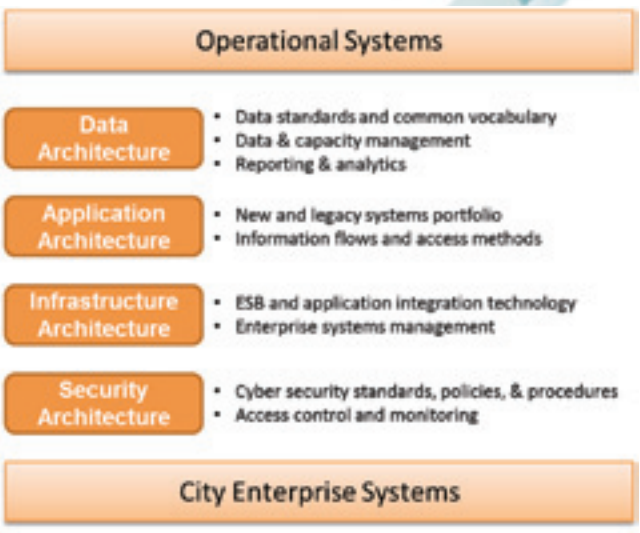
An ESB solution provides synergies by utilizing a common integration platform for the many applications. It reduces the overall number of application interfaces needed to be constructed, deployed and maintained for the Smart Grid program. Due to its sophistication, the adoption of an ESB platform was once considered beyond the capabilities of a municipal utility and reserved for large IOU class deployments. However, Glendale determined that the interoperability facilitated through the use of integration standards could actually provide more benefit to them as an organization. For example, the ESB eliminated the need to continually spend to support on extensive custom integration for point-to-point application interfaces for an increasing number of Smart Grid applications and systems.

The Transition Process

The City of Glendale is now transitioning from technology selection to the beginnings of concurrent implementations of various Smart Grid systems. GWP has successfully completed the installation of AMI for each of its electric and water customers. By using the Smart Grid Reference Solution Architecture as a planning tool, the city can ensure adherence to the architecture and fulfill the data access needs of each department.



This system often requires trade-offs, and at times, concessions to either avoid duplication of functionality by utilizing systems to serve common requirements or prevent the fall back position of silos in OT/IT. For example, one approach to asset management considers city-wide assets regardless of whether they are parts of the electric or water infrastructure. Glendale realized an immediate benefit of the new approach with a degree of coordination, cooperation and communication between the GWP and city departments, which was often tenuous prior to the adoption of the Smart Grid architecture. Other current phase activities include:

- Development of a common data model and standards for messaging, which are used to guide the acquisition and implementation of all systems. The city is establishing architectural guidelines for applications and databases to improve maintainability and reduce costs.
- The creation of an Information Technology Executive Board, with members of both IT and OT, to track and evaluate new technologies and systems and ensure alignment with standards and the overall architecture.
- Implementation of an Enterprise Service Bus (ESB) across all GWP and city applications to provide a shared integration platform and reduce ongoing integration and maintenance costs through standardization.
- Implementation of new and enhanced applications as planned including DMS, OMS, & Water SCADA, and Water Work Orders leveraging the established standards.
- Formalizing security policies and standards across GWP and city organization, including the establishment of a Security Architecture Review Team.
- Enabling an Organizational Change Management program that establish roles, responsibility and organization to best leverage the Smart Grid Architecture and realize benefits.
- Initiating a formal Program Management Office (PMO) framework and an approach to risks & dependencies management, change management, and overall project management.

Smart Benefits Reach Main Street

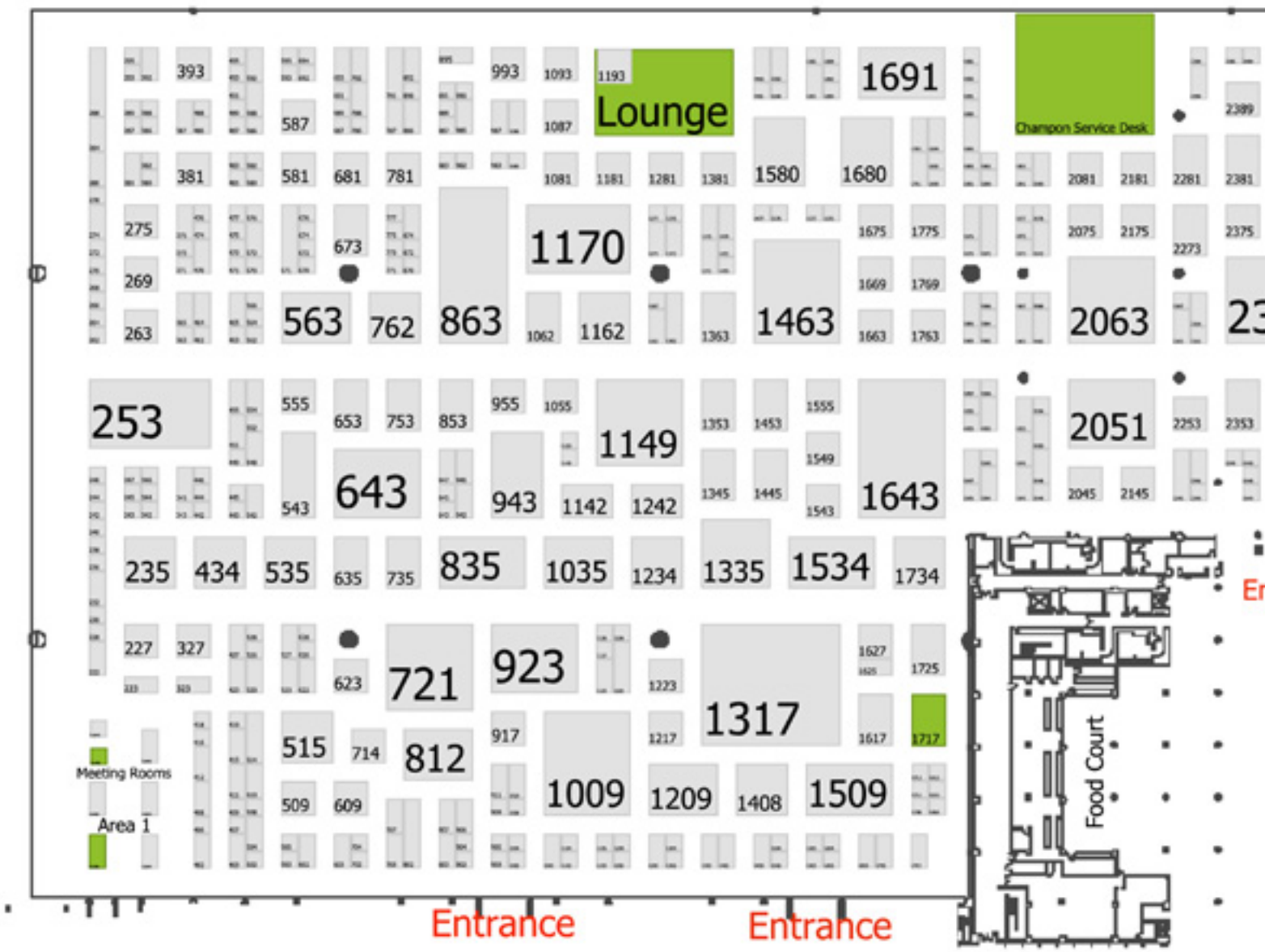
Beyond electric operations and customer services, other city services will benefit from the Smart Grid integration. The City of Glendale's water, public works, police and fire services will be able to share data. The adoption of standard information models, including IEC[1] CIM, is increasing interoperability among a highly heterogeneous application portfolio. In the future, the city will be able to manage the sharing of operational information with outside agencies. For example, future integration may include integration with the Department of Homeland Security's UICDS[2] standard, allowing for multi-jurisdictional emergency operations management and coordination. When the 21st Century integration of Homeland Security with local government services is practical, the City of Glendale will be among the few cities well positioned to realize the full benefits of that integration.

Through the combination of a pragmatic approach to enterprise architecture, a strategic acquisition of technology, a tactical augmentation on critical skill sets, and the adoption of a sustainable program governance framework, the City of Glendale is well on its way to meeting the Smart Grid challenge -- without the need for a large department of personnel or an army of contractors. Ultimately, Glendale's foresight in making an enterprise-wide investment in systems integration technology, standards and new processes is laying the foundation for a Smart City, whose benefits extend in practical ways to all of its consumers on Main Street.

[1] *IEC – International Electrotechnical Commission*
[2] *Unified Incident Command and Decision Support - standards based interoperability for emergency operations.*

About the Authors

Edward Fraga is Director of Information Services for the City of Glendale Water and Power. **John Wambaugh** is senior vice president and **Joe Tellez** is vice president of Smart Grid Integration Consulting for UISOL (Utility Integration Solutions). The three have collaborated to design and deploy GWP's Smart Grid architecture and to craft this article.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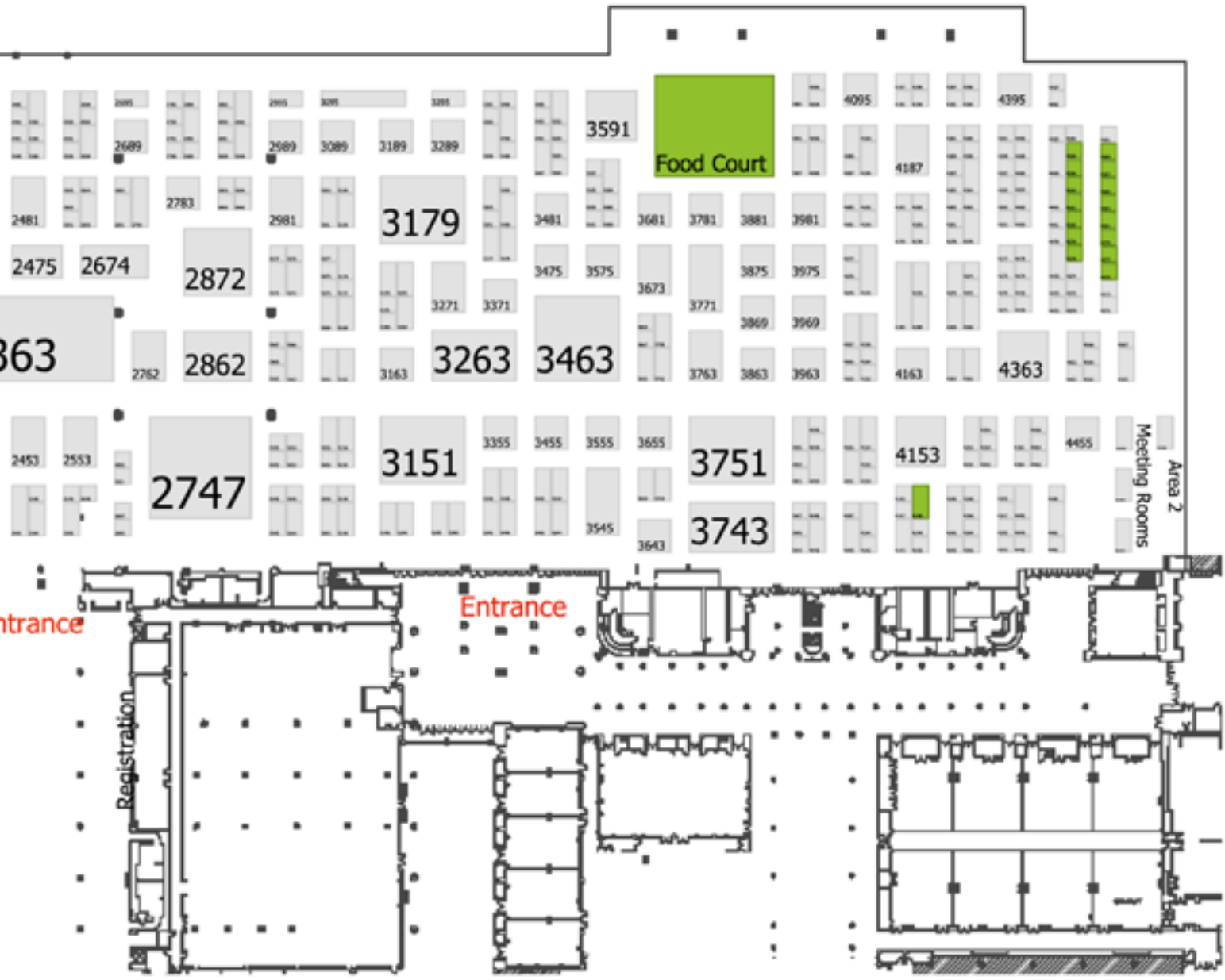

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Scheduling and Dispatching Success at Lee County Electric Cooperative

By Donald King, Senior Supervisor for Electric Operations, Lee County Electric Cooperative

Linemen live for emergency repairs. Along with emergency work, they also love scheduled overtime – the kind of job where they have to replace, for example, a transformer at a large shopping center. However, making the distribution of that work fair and equitable can be an ongoing challenge for utilities.

Economics can change the type and amount of work a utility has to accomplish, thus affecting schedules. Living in an area where summer storms can wreak havoc on electrical systems, necessitating a large amount of the workforce to report for emergency work, often confounds well-oiled schedules too. Other factors affecting the smooth scheduling and dispatching of linemen include limited – or a lack of – technology for determining the location of resources and order of callout. At times, technology creates unexpected consequences.

These challenges do not bring scheduling or dispatch to a complete halt or cause power restoration work to go unfinished, but they can delay the process, cost considerable time and money, and make it difficult for managers to get a global view of what is happening on their watch.

The process for scheduling and dispatch at Lee County Electric Cooperative (LCEC) has worked well. In fact, LCEC has always been able to maintain the approximately 8,000 miles of energized line it owns in Southwest Florida. However, there was room for improvement in the process for the supervisors and nearly 60 linemen and apprentices employed.

Scheduling Crews in a Changing Economy

In the last four years, among the biggest scheduling changes LCEC's electric operations group has seen was the shift from a large amount of capital build-outs (i.e., expanding the LCEC infrastructure to accommodate for growth in Southwest Florida) to focusing, instead on internal projects. As we went through the economic downturn, LCEC had a sizable workforce working the 7 a.m. to 5 p.m. schedule, geared for completing the large demand for new service work and customer installations. Where we once had difficulty meeting customer demands to get a lineman on site, we now were having difficulty filling the schedules with work. We were also saddled with rising overtime costs and our measure for customer-related power outages, SAIDI (Sytem Average Interruption Duration Index), was on the rise.

We started by looking at our daily, monthly and annual workload. Ideally, we wanted to get most of our work done during the day, but we also needed to reduce the overtime burden and improve SAIDI. Our goal was to staff most efficiently to meet these competing demands. We reviewed data that we had on hand – types of work, available days and hours, and cycle-time on electrical lines that required service call outs.

Next, we arranged our shifts to be staggered throughout the day to best address those competing demands. Further, shifts were designed to change with the weather, so to speak, to meet the challenges of the higher callout rate during the summer. Ultimately, our analysis helped us restructure our shifts to obtain 24-hour coverage with 12 starting times. The result has been a significant decrease in LCEC's overtime, and a sizable contribution to a 25 percent year-over-year decrease in the utility's SAIDI since 2010.

Over time, LCEC has established a baseline for the number of line personnel needed to complete its forecasted workload for the year. We set up crew structures to complete the different types of work that are common in the industry. For instance, one type of structure is for larger crews handling infrastructure expansion, and another type is a one-man crew that troubleshoots or takes care of customer appointments.

We arranged the crews in shifts throughout the day, which provides flexibility in pairing up crews to complete work and to provide coverage for outages. We analyzed our callout activity, determined what hours were the most active and established shifts in these areas to handle that demand.

Like many utilities, LCEC relies on contractors as its flexible workforce. The utility expands and contracts those requests for help, depending upon the amount of work it faces at any given time. LCEC has supervisors who oversee the internal electric operations workforce and another group of managers who coordinate contractors.

LCEC schedules its contract workers to handle more of the engineer-designed and capital build-out projects; in general, LCEC has structured scheduling so that its contractors tackle the production work. By relying on its contractors to arrive at a jobsite to set poles and string wire, LCEC's schedule isn't impacted as much when linemen and supervisors are required to address service calls, attend company meetings or participate in training activities.

The LCEC electric operations group also has a crew, which it calls a "build-out crew," which is designated for capital projects. This provides an additional crew at the ready for build-out projects when needed. LCEC linemen and apprentices are rotated in and out of the crew, so that their skills remain sharp.

Scheduling for Weather

The LCEC service territory covers a vast geographical area. In major storm-related restoration situations, the utility taps its internal supervisors to lead a team with both LCEC personnel and contractors. A typical crew for a catastrophic weather event would have a supervisor leading three LCEC personnel, three contractors, one runner who would handle mapping outages and damage, and a logistics coordinator to address equipment needs for the crew. Arranging housing, food and laundry for the crew is handled at another level of the organization, allowing the electric operations team to focus on restoration.

LCEC has pre-arranged disaster plans, each of which varies slightly depending on the timing and magnitude of the weather event (e.g., CAT 5 hurricane versus CAT 3). For each weather scenario, pre-determined levels of needs and methods for securing resources help to streamline the worker dispatching process.

Deploying Technology for Scheduling, Dispatch and Callout

Prior to 2010, LCEC relied on a system designed to dial line personnel when storms, power outages and other events struck. But the tool offered no reporting, metrics or analysis. That challenge was overcome in 2010 when LCEC implemented cloud-based software that automatically tracks the status of linemen. The automated crew-calling system, developed by ARCOS, Inc., also launches programmable callouts to bring linemen together in crews when needed and in compliance with LCEC rules and bargaining unit agreements.

Prior to implementing the automated crew callout system in 2010, we incurred several bargaining unit grievances each year, mainly due to errors in placing manual callouts, which in turn, have a negative financial impact on the organization. The ARCOS Suite gives LCEC supervisors and dispatchers a view of personnel on-site, personnel due on-site, linemen on sick leave and workers on vacation. It also enables LCEC to prepare long-term planning for crews and efficiently manage personnel leave. Since implementing the new system, we have not had a single callout-related grievance filed. The system also provides up-to-the-minute, accurate statistics on callout, whereas our previous callout data collection was prone to errors, since LCEC compiled statistics manually. Moreover, the quality of the callout statistics has vastly improved and has become a useful tool throughout the organization.

By managing our callouts and scheduling with the automated system, our callout response from the linemen has also improved. The system also reports on LCEC's turnout ratio for callout (i.e., the percentage of people we have answering calls). LCEC aspires to have a 33 percent turnout ratio on callout. When linemen are not meeting that threshold, we pull the data to show them both the callout goal and current performance and then discuss areas for improvement.

The LCEC electric operations team also uses a work management system to define work, schedule hours and track progress. Using an automated mapping and outage reporting system and geographic informtaion system (GIS), LCEC is able to extract data from the appropriate database. We then use another application for designing reports from the various data sources to see the details and timeframes of every outage. This helps LCEC supervisors identify when staffing or scheduling changes are needed.

When calls come into the LCEC outage management system, it records them and dispatchers determine the number of resources needed. If there is a shortage of linemen who can respond, LCEC schedulers turn to the callout system to see who is onsite and available to work. They can also use the ARCOS system to launch a callout. When a lineman calls in sick or takes an unplanned absence, the system captures this information, allowing resources to be adjusted accordingly.

Measuring Success

LCEC department metrics measure success across a number of areas including quick service installation dates, lighting repair turn-around and maintenance work. There are annual targets that supervisors and linemen must meet as part of that work. And, of course, LCEC measures itself on callout response. On a corporate level, all of the LCEC repair and maintenance work feeds into SAIDI, which is a company KPI (Key Performance Indicator).

Wringing Efficiency from Analysis and Automation

Without technology, LCEC would not have the ability to collect and analyze the data that allows for split-second, objective decisions about scheduling, dispatch and restoration. A utility can make decisions from the gut or because of the influence of a large customer, but those kinds of decisions can be problematic. For example, in any given year, we may have one bad week of outages across a stretch of afternoons. The outages are real, and they do affect customers, albeit a subset of the overall service area. This enhanced ability to analyze data allows LCEC supervisors to more easily identify and separate actual outage data from periodic system anomalies. In that case, it would not be prudent to change shift coverage as a result of those rare events since changing shift coverage for such reasons could possibly impact efficiency down the road.

Today, we have a much better baseline in place for decision-making than we did two years ago. We can notify line personnel within seconds of an outage and track their status until power is restored. In addition, we have the operational metrics to help us monitor response time and availability of linemen, which roll up into higher level metrics that measure the average outage duration for each customer.

About the Author

Donald King is a senior supervisor for Electric Operations at Lee County Electric Cooperative. He is based in the utility's North Fort Myers, Fla., operations center. King joined LCEC in 2004 as a senior supervisor in charge of contractor operations. Before that, he spent his career in the telecommunications industry handling around-the-clock, mission-critical operations. King received his bachelor's degree from the University of Maryland, College Park.

Strategies for Building and Operating a Secure, Scalable and Reliable Smart Grid

By Ray Bariso, Head of Smart Grid Solutions, Telcordia

When the National Academy of Engineering (NAE) named 20 engineering achievements that had the greatest impact on quality of life in the 20th century, electrification ranked No. 1. Telephony and the Internet ranked 9 and 13, respectively. When the NAE ranks the 21st century's greatest achievements, it's a safe bet that electrification, telephony and the Internet will continue to top the list moving and move a step closer to becoming a single category: The Smart Grid.

That outlook is based on two things: the challenge of building smart grids and the benefits for utilities and society when that challenge is overcome. The first step in meeting that challenge is to understand that a Smart Grid is only as smart as the communications network behind it. That fact often gets overshadowed by all of Smart Grid's bottom-line and end-user benefits – ironic, considering that a reliable, flexible, manageable, scalable and secure communications network is critical for achieving those benefits.

The next step is accepting that the Smart Grid is more of a revolution than an evolution. Implementing the Smart Grid involves a complete transformation of how utilities do business, from how they manage their assets to how they serve their customers.

A prime example is how, over the past century, every aspect of the utility business – including its communications infrastructure and processes – has centered around one-way delivery of services. But that architecture already is steadily changing, as one-way automated meter reading (AMR) gives way to two-way advanced metering infrastructure (AMI) and demand response (DR) systems.

Two-way communications enables key aspects of the Smart Grid, such as distribution automation (DA) systems, which reduce the number of customers affected by anomalies, interruptions and outages by adjusting the direction of power flows. DA systems complement emerging technologies, such as faulted circuit indicators (FCIs) that use cellular or private wireless to report problems directly to the utility's outage management system. Instead of requiring line personnel to walk around looking for a change in their mechanical or LED indicator, these next-generation FCIs enable utilities to pinpoint and resolve problems quickly and far more cost-effectively.

A New Era of Complexity

As two-way communications become increasingly important for how utilities do business, they face another challenge: selecting and managing disparate communications network technologies supplied by multiple network equipment vendors. These include 2.5G, 3G and 4G cellular, WiMAX wireless in a few cases, SONET/SDH, IP, MPLS and Ethernet.

There will be comparable fragmentation on the communications service provider (CSP) side, too, where utilities likely will use one CSP's fiber network, another CSP's copper network and still another CSP's cellular network, all in addition to their own private wireless network. Utilities that serve a large geographic area will have additional complexity if it turns out that, for example, no single CSP has fiber infrastructure everywhere that they need broadband connectivity. **Figure 1** illustrates these and other challenges.

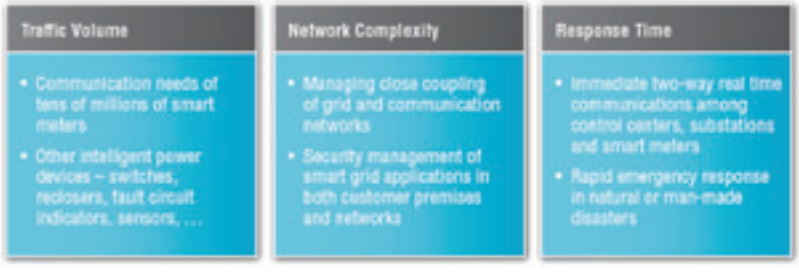

Figure 1: Communications network challenges for the smart grid

The good news is that as daunting as the communications complexity might sound, it's comparable to what telcos, cable operators, mobile operators and other CSPs have been successfully managing for decades. The secret to that success is to mask the complexity through the use of communications network management software tools and processes, which provide end-to-end network visibility and powerful, user-friendly performance dashboards that convert data into actionable information.

A few savvy utilities – more about them in a moment – have begun leveraging those kinds of tools and processes as they implement Smart Grid. It's clear that their peers will have to follow suit sooner rather than later. There's simply no other way to manage a large, complex, multi-technology network.

The Utilities Telecom Council estimates that of over $3 billion that the US utilities spent on telecom in 2011, about $50 million was on network management. That's around 2 percent. By comparison, CSPs typically spend between 5 and 10 percent annually. That difference shows that utilities should consider more investment in communications network management tools as their communications networks become more complex.

The telecom industry has introduced and optimized operations for multiple communications technologies such as fiber optics, digital transmission, IP networking and wireless over the past few decades. Utilities, however, will be implementing all of these technologies in a much more compressed timeline.

Smart Moves to Build a Smart Grid

To help address the challenge of managing networks comprised of disparate technologies that's flooded with constantly increasing amounts of data, utilities can leverage many of the telecom industry principles and platforms associated with the communications network management discipline. For example, utilities need the ability to:

- Create a highly accurate database of Smart Grid devices such as FCIs, meters and DR modules, as well their communications network infrastructure. The latter includes both the physical network elements and the logical network assignments, including locations, equipment instances, connectivity, paths and capacity-supporting technologies such as SONET/SDH, Ethernet, leased lines and cellular.
- Automatically and continually compare the deployed network components to the inventory database to identifying and correct discrepancies. As a result, utilities can run lean operations, instead of buying, storing and deploying more than they need, because they now have end-to-end view of their entire communications network.
- Automate the process of commissioning and configuring network devices to avoid the cost, lead time and mistakes that come with manual provisioning.

Unless a utility already has ample hands-on experience operating a large-scale communications network, it should look for assistance from third parties that have that experience. Those partners can help with major tasks such as:

- Network planning and design, including providing architectural recommendations and detailed designs regarding capacity, resiliency, security, configuration and network addressing requirements. The ideal partner also can help develop network equipment requirements and assess RFP responses, as well as support the utility's technology integration and test plans.
- Business process re-engineering, including staff and leadership, systems, technology and data. This step should include assessments to provide an implementation roadmap for identifying and tracking Smart Grid goals.

- Capital budgeting and asset management, which is key for optimizing the efficiency of the entire Smart Grid entire portfolio from both an operational and financial perspective. The assets should include communications networks, power grid, IT, land and vehicles.

With the evolution to the smarter grid, utilities will have a lot of new and different data to manage. Each intelligent device will have identification, connectivity, configuration, attribution, alarm, performance and other types of data. Tens of hundreds of millions of data records will come from smart meters and machine-to-machine devices. How can utilities collect, store and analyze all of the data that Smart Grid devices are capable of providing?

The ideal network management solution gives utilities the ability to sift through the data, compile key performance indicators (KPIs) in near real-time and instantly push results to a dashboard where managers and executives can quickly assess the health of their network enabling actionable operational decision making. The solution also should provide the insights necessary to make informed business decisions, such as where to deploy additional network resources, how to proactively identify areas of poor communications network performance, and identify potential cybersecurity vulnerabilities and threats before a breach is encountered.

Figure 2 illustrates a holistic approach to looking at the major components of an effective Smart Grid communications management strategy that links the power grid to a secure multi-vendor communications network. It is built on a three-pronged operational foundation: network planning, network provisioning, and network assurance. Overarching all of these are the very important areas of network operations and network security.

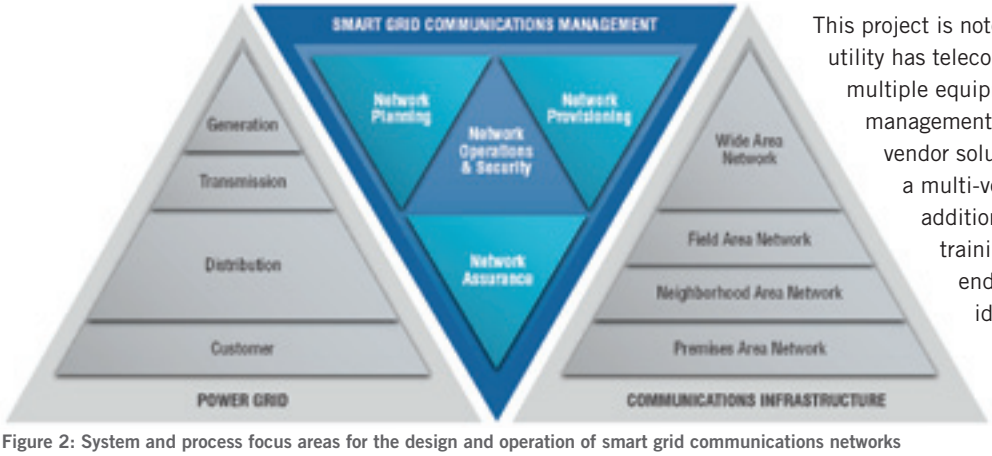

Figure 2: System and process focus areas for the design and operation of smart grid communications networks

Implementing a Smart Grid ultimately is an exercise in convergence: of power grid, information technology, and communications infrastructure. To successfully operate this complex triad, a communications network management platform will provide the foundation for convergence and enable utilities to execute their Smart Grid strategies effectively and securely.

Three Success Stories

To appreciate how communications network management enables utilities to successfully develop and execute their Smart Grid strategies, consider the following real-world examples:

- **Case #1:** An electric utility owns an extensive fiber network that it uses for its internal data communications for managing the power grid. The utility also sells communications network capacity and services to enterprise customers. It implemented a network management platform in order to have a single set of tools for all aspects of the fiber network.

  With the platform providing end-to-end network visibility, the utility was able to reduce the time spent identifying failed circuits from hours to minutes. With increased responsiveness, contact center staff and other employees were able to be more productive as outages were able to be identified and repaired more quickly, and less commercial revenue is lost.

- **Case #2:** Another electric utility owns both a large Ethernet and IP-based fiber network, and a legacy microwave network. One of its first Smart Grid applications is a recently implemented wireless AMI solution. The utility wanted a single, integrated network management platform capable of handling all of these disparate networks, applications and technologies.

  This project is noteworthy partly because like most, this utility has telecommunications infrastructure from multiple equipment suppliers. When assessing network management solutions, the shift from multiple single-vendor solutions to a system capable of supporting a multi-vendor network, should be paramount. In addition to operational efficiency and reduced training time, a multi-vendor system provides an end-to-end view, enabling the utility to quickly identify specific points of failure.

- **Case #3:** A third utility was in the early stages of developing their Smart Grid evolution plan. As part of that plan, they wanted to complete a comprehensive physical and cybersecurity assessment and put in place operational processes associated with on-going management of potential security vulnerabilities and threats. This utility, in conjunction with cross-industry cyber security consultants, developed a comprehensive security architecture, which included assessment, testing and considerations for the wireless networks they were deploying.

As they utilities show, when multi-layer, multi-technology, multi-protocol communications networks are properly designed and managed, the result is a Smart Grid that's reliable, scalable, secure and cost-effective. In the process, these utilities have completely transformed how they do business, enabling them and their customers to reap all of the benefits that come with what will be one of the 21st century's great technological achievements.

About the Author

Ray Bariso has 20 years of management, business and technical experience developing, delivering, selling and managing complex software and services solutions. He has held various roles in systems engineering, solution architecture, consulting, program management & delivery, sales & marketing and product line management. His current responsibility includes managing Telcordia's Wireless & Smart Grid solutions business, which includes the definition and execution of Telcordia's overall Smart Grid go-to-market strategy, partner ecosystem development, solution architecture, and business management.

Bluebonnet Unlocks the Potential of its Field Operations with Mobile Workforce Management Solution

By Ronnie Bludau, Operations Technology, Bluebonnet Electric Cooperative

In 2011, Texas experienced one of the worst droughts in the state's history, with very little rainfall and record high temperatures. During the state's wildfire season, which persists from mid November through late September, firefighters responded to an unprecedented 23,519 fires that burned an estimated 3.8 million acres and more than 2,800 homes. On the Labor Day weekend, the most devastating of these wildfires raged through Bastrop Country in Central Texas, claiming 34,000 acres and destroying 1700+ structures.

Bluebonnet Electric Cooperative, one of the largest electric co-ops in Texas, began its major restoration effort three days after the wildfires. More than 200 miles of Bluebonnet's electric lines fell inside the burn zone. All told, 4,300 meters lost power, 632 poles and 45 miles of line were replaced, and crews worked 252 miles of right-of-way in the aftermath. Normally, an event of this magnitude would keep crews on the frontlines for months – but Bluebonnet's crews, bolstered by 450 contractors – had all power restored roughly three weeks later. What made the difference? According to Bluebonnet, teamwork, training and mobile workforce management technology.

In 2009, driven by the CEO's vision of paperless workflow between field crews and the office, the co-op had kicked off a multi-year, multi-phased enterprise software project to go mobile with 30+ service order types. Since streamlining routine field operations with its mobile workforce management system, the coop has experienced dramatic results, including a 50-60% faster order closure rate and an 80-90% reduction in radio traffic. And in the face of September's massive wildfires, the solution proved invaluable in helping Bluebonnet to safely, quickly and efficiently get the power flowing again to its members.

A New Beginning

In 2004, a new management team put Bluebonnet on a quest to become the "best co-op in the country." To guide the process, Bluebonnet chartered a mission and a strategic vision that improved member service. A number of significant projects were identified to support the ambitious transformation the company was seeking, and implementing a mobile workforce management solution was one of them.

As Bluebonnet began to more closely examine field service operations, the existing approach was compared to major congestion on the interstate: lots of problems inhibiting meaningful momentum. Members were geographically dispersed over a large area; crews relied on manual, paper-intensive order procedures; communication between the office and the field was limited to the start and end of the work day; and information was often delayed, not accurate – or worse still – unavailable. The company also wanted to enhance compliance with the Federal Trade Commission's Red Flags Rule that protects its members' information from identify theft. The executive mandate was to find opportunities in the problems and to dramatically alter the state of its field operations… and Bluebonnet did.

Now entering the fourth phase of its multi-year implementation cycle, Bluebonnet's mobile workforce management solution has brought about a fundamental shift to paperless workflow between dispatch and the field, dramatic gains in capacity in terms of the number of orders completed per month and, quite unexpectedly, instrumental outage restoration efforts in the wake of massive wildfires that destroyed more than 1,700 structures in September of 2011.

Bluebonnet Unlocks the Potential of its Field Operations with Mobile Workforce Management Solution

Going Mobile

Bluebonnet provides electricity to members in 14 counties over more than 3,800 square miles, serves more than 82,000 meters and maintains 11,000 miles of power lines. After implementing a new SAP R/3 system in 2005 and a new GIS in 2007, the company turned its attention to another strategic technology innovation: a mobile workforce management solution. The system closes the gap between the office and the field with dispatching and mobile applications that use real-time wireless communications to manage day-to-day field operations. It eliminates the costs and inefficiencies of voice communication and paper-based data collection in the field and data entry in the office.

Dispatchers and supervisors send order assignments wirelessly to crews, easily monitor the progress of work with real-time status updates and make informed decisions in response to alerts and emergencies. Ronnie Bludau, Operations Technology, Bluebonnet, explains: *"Mark Rose, our CEO, envisioned paperless workflow between dispatch and crews, crews working directly from their trucks, and work completed without any manual interaction or human intervention in the field or the office. Given the scale of this type of change, we formed an interdisciplinary team on the mobile project. It included operations as well as engineering, GIS and IT. After the evaluation process was complete, we selected the mobile workforce management solution from Clevest Solutions and got to work."*

A Phased Approach

The project team identified 31 order types and processes for mobility and real-time communication. In May 2008, Phase 1 of the implementation began with six of these, which represented the most common and critical types of orders. The first interface between the Clevest mobile workforce management solution and the SAP R/3 system also went live at this time. With 80 vehicles equipped with laptops, Bluebonnet's field team received this first subset of order types wirelessly and sent order completion details in real-time back to the office – and seamlessly to the SAP system.

Bluebonnet subsequently rolled out 14 more order types in Phases 2 and 3 of the project, including an interface between the workforce management solution and the new GIS, as well as the ability for Bluebonnet's crews to create orders in the field as required.

Bludau elaborated, *"On average, we went live with one new order type per month, and the multi-phased approach we took to the project worked well. It helped us to prioritize and focus our efforts, gave us a more controlled environment to learn within, and generally made an enormous undertaking much more manageable."* In Phase 4 of the project, planned to begin in early 2012, Bluebonnet's objective is to implement its last 11 order types.

Dramatic Results

For Bluebonnet, the results of going mobile have been compelling across many aspects of the business. The shift to paperless workflow has galvanized significant savings associated with work order closure. With far less administration and manual involvement required, the function is now handled by a team of five instead of seven, and employees formerly part of the group have been redirected toward higher value work. Daily radio traffic and telephone calls have been reduced by a staggering 80 to 90 percent, and the resulting quiet has allowed for improved concentration for dispatchers and supervisors who work more now on managing alerts and emergency conditions when they arise. For crews in the field, it has meant much faster work order closure…

"Field crews no longer have to phone in to an order close out group, and get frustrated by busy signals only to finally get through and learn they've not met the necessary validation on a particular order," explains Bludau. "The system relieves them of this kind of time-consuming administration and lets them focus more on the work at hand."

By eliminating manual, paper-based processes, Bluebonnet has also achieved standards of data accuracy and protection that previously were unattainable. With reliable and encrypted customer information in every interaction, Bluebonnet is meeting nationwide requirements for an effective Red Flags program to maintain the privacy of customer information and to ensure the information is not at risk.

The ability to append external attachments to an order, whether from the field to dispatch or vice versa, is one particular feature that has proven instrumental in improving the accuracy of information. For example, instead of writing down serial numbers and meter reads for meter swap orders, crews now simply attach a picture of both the old and new meters to the order, which eliminates any errors in serial numbers that reside in the SAP system. Costly errors are caught and corrected early, and any meter tampering or damage is recorded and shared immediately so it can be effectively addressed. Bludau also notes that crews have a bonus plan tied to error-free billing…

"Mobile data has improved billing accuracy so much so that the team routinely exceeds targets and is rewarded accordingly," he explains.

In addition to the operational benefits associated with going paperless, Bluebonnet has also realized dramatic gains in capacity across its field operations. More than 2,500 work orders are now processed each month using the mobile workforce management solution. Each field tech is completing more work on a daily basis. Crews start the day from home as they no longer need to drive into a dispatch center for orders. They gain productive time throughout the day with real-time wireless communication and required order and asset information at their fingertips. Crews are assigned areas and work efficiently in their area; they no longer end up accidentally working in side-by-side locations. Improved productivity and efficiency in the field has also translated into fuel savings as crews spend more time working and less time driving.

Bludau emphasizes, *"The field team has been really positive about the system since its initial installation. It makes their jobs easier; they enter a bit of information and they're onto the next order."*

Bludau goes on to describe the most telling endorsement in this way: *"When it's taken offline or goes down temporarily, they complain!"*

In the Line of Fire

In addition to streamlining routine field operations, the mobile workforce management proved invaluable in September 2011 during a major natural disaster – not only to workers in the field, but also to the public at large in terms of ensuring safety during the restoration efforts. Feeding off one of the worst droughts in the state's history, combined with high winds and record high temperatures, massive wildfires raged through Bastrop County in Central Texas over the Labor Day weekend. More than 200 miles of Bluebonnet's electric lines fell inside the burn zone, which ultimately claimed 34,068 acres and destroyed 1,670 homes and 40 commercial buildings.

The business agility of Bluebonnet during the emergency and major restoration effort was unprecedented. With its own headquarters in danger, the co-op was forced to evacuate and move swiftly into a backup control center. Immediately the mobile workforce management solution was available for dispatching orders, with no disruption. The company's field workers were joined by 450 contractors called in from Asplundh, McCoy Tree Service, Line Tech, Clay Richardson Construction and T&D. Crews began restoring power three days after the fire began, and worked 14- to 16-hour shifts until all power was restored, roughly three weeks later.

Normally, during an event of this size, it would take months to restore all service. All told, 4,338 meters lost power at the peak of the fire; crews replaced 1,000 poles, 56 miles of line, 250 transformers and worked 252 miles of right-of-way – with all activities in the field supported by the mobile solution.

According to Bludau, *"It was a huge contributing factor. Without it, everything would have slowed down and delayed communications and the completion of work."*

Bluebonnet initially estimated restoration efforts would take approximately five weeks. What made the difference? For Bluebonnet, the answer is clear: technology, training and teamwork all helped to reduce restoration time by almost two weeks – and all of this while the co-op continued to serve the roughly 90 percent of its members who were not affected by the fire.

Finally, safety is a foundational value for Bluebonnet. The co-op's Emergency Response Plan, including the functioning of its mobile workforce management system, is constantly evaluated and is adaptable to all emergencies. Once a year, Bluebonnet stages a mock event to test the plan's effectiveness as well as the emergency response team's readiness. Thanks to this preparedness and ongoing commitment to safety, in the face of the Labor Day fires, the co-op was able to evacuate its headquarters quickly and without incident.

Looking Forward

The results spurred on by Bluebonnet's mobile workforce management solution have – at their core – transformed member service, which was the impetus for the company's multi-year metamorphosis. The field tech is the face of a utility organization and crews are on the frontlines of member service; anything, therefore, that brings about changes to field operations will directly affect the customer's experience of the company.

For Bluebonnet, its mobile workforce management solution does just that. The co-op continues to pass on the benefits of the system to its members, and anticipates additional savings and efficiency gains this year as the project enters its final phase. The company is also evaluating the potential for implementing Clevest's outage management capabilities as part of its ongoing commitment to industry-leading rapid response and emergency preparedness – which has already been put to the test!

About the Author

Ronnie Bludau is Operations Technology Superintendent for Bluebonnet Electric Cooperative. He is responsible for telecommunications, AMR and GIS departments at Bluebonnet Electric, as well as project management for mobile data and new metering technologies.

Consumer Confidence at NV Energy

By Jeff Evans, Executive Consultant, Black & Veatch

Utilities across the nation are in various stages of implementing smart metering solutions. Once fully implemented, these solutions are expected to enable new capabilities and extensive benefits to both utilities and consumers. Fully realizing those benefits will require that consumers embrace new perspectives and understanding of their energy usage patterns and use these solutions and the knowledge they provide to alter their energy consumption habits.

Positive change for the energy consumer (and the utility) will not be realized unless:

- Consumers believe that the smart metering systems and tools work as promised
- Consumers adopt the technologies provided for them
- Consumers believe that the utilities implementing smart meters are competent, trustworthy, and focused on customer benefits

An effective consumer confidence plan will, over time, confer the capabilities of smart meters and the confidence in utilities implementing them.

NVEnergize

NV Energy is implementing *NVEnergize*, a strategic Smart Grid project incorporating smart metering and various systems needed to realize benefits to Nevada customers and to NV Energy. Early in its planning phases, the *NVEnergize* team recognized the need for a well formulated plan to instill confidence in consumers about the new program and NV Energy's ability to implement such technology to the benefit of consumers. The Department of Energy agreed with this approach and awarded NV Energy additional matching Smart Grid Investment Grant (SGIG) funds beyond their initial SGIG funding to implement a comprehensive Consumer Confidence Plan.

NV Energy's Consumer Confidence Plan consists of six key steps that, when executed, demonstrate the key elements necessary to instill customer confidence. These steps have been implemented at NV Energy in sequential order as each provides the foundation for the next. Together, they provide a framework that all utilities might execute when implementing transformative smart grid programs.

Step 1 – Security/Safety

As with all information technology systems, the implementation of smart metering creates new opportunities for nefarious individuals to try to breach utility security and compromise utility grid management systems. Utilities are keenly aware that these new security risks should be fully addressed in a comprehensive risk management strategy. To address this, utilities embarking on smart metering deployments are implementing wide-ranging security plans and updating security policies to address identifiable risks. These plans and policies must be flexible enough to monitor and understand both known and unknown risks.

Utilities receiving investment grants through the DOE have created cyber security plans as a part of their SGIG programs. These dynamic and flexible plans provide the outline for security-related activities throughout the utility and are intended to evolve throughout the lifecycle of the smart grid deployment and operations project.

NV Energy's Cyber Security Plan incorporates existing NV Energy security practices and includes a number of incremental investments in security measures, including third-party assessments, to protect and monitor the smart grid network.

The Cyber Security Plan also addresses security associated with other components of the *NVEnergize* solution including the Meter Data Management System (MDMS), the Demand Response Management System (DRMS), Home Area Network (HAN) devices and the Customer Portal.

As smart meter deployments have proceeded, public concern about possible public health impacts has increased. Chief among these concerns is the perception that RF emissions from wireless smart meter implementations may somehow be harmful to human health. While this concern is scientifically unfounded and has been addressed by independent analyses and publications, utilities still must respond to the concerns expressed by their customers.

Utilities should use the full breadth of their communications media to reach concerned constituents and provide well founded and supported facts to reduce consumers concerns about these issues. Several states and regulatory bodies have studied smart metering health claims in depth. Many of these study results are available to support the education of concerned utility stakeholders. As part of its efforts, NV Energy employed an independent third-party to validate that the potential RF exposure of their smart meter system is well within allowable FCC standards. Copies of these independent studies and resource materials are available to consumers via email, web or through public outreach events.

Step 2 – Privacy

The protection of customer sensitive data (i.e., personally identifiable information) is also a significant concern to consumers. During the course of typical utility operations, customers provide the utility with private customer information for purposes of delivering and billing for their energy commodity. The customer usage data captured by the smart meter systems should be afforded the same privacy considerations. Private customer information is typically stored in a secure corporate data center that is both physically and logically protected.

This broadened need for privacy demands that utilities have strict privacy policies in place, either implemented proactively or at the behest of a regulatory body that ensures the protection of customer-sensitive data. This must include that personal/private information is not broadcast over the AMI network.

NV Energy takes the privacy concerns expressed by consumers regarding smart grid implementations very seriously. NV Energy is evaluating the type of data collected and how it is secured at every stage of its use in supporting both the utilities internal operations and the enablement of customer programs. In many cases, NV Energy is adding security protections beyond those required by law. This often includes securing some data, whether or not it contains sensitive information, to ensure the most prudent protection of customer privacy.

Step 3 – System Accuracy

Accuracy of energy measurement in North America is governed by American National Standards Institute (ANSI) standards. These standards apply to all meters, including both conventional and smart meters, and were implemented long before smart meters existed. The standards have evolved to increasingly tighter tolerances with the advent of more granular measurement afforded by smart meters.

During meter manufacturing, every electric meter produced is tested to ensure compliance with ANSI standards for accuracy. Prior to accepting a new meter for use on their system, utilities will traditionally conduct first article testing – an industry-standard set of tests that verify compliance with ANSI meter accuracy standards and conformity with the functionality claimed by the meter manufacturer. First article testing is more rigorous than subsequent testing of shipments of meters.

A sample of each meter shipment is re-tested for continuing compliance with ANSI standards for accuracy. NV Energy sample tests a random five percent of all delivered meters to assure confidence in the accuracy of meters deployed. Subsequently, throughout the life of an installed electric meter, ANSI standard accuracy testing is conducted on a periodic basis on a sampling of the installed meters. Selected meters are removed from the customer premise and tested in the utility meter shop to verify accuracy.

Recognizing the potential for increased scrutiny of their new smart meters, NV Energy implemented additional steps to validate the accuracy of these new devices. NV Energy contracted with the University of Nevada at Reno (UNR) to independently test the accuracy of meters. UNR used the National Institute of Standards and Technology's (NIST) certified WECO[1] test board to test NV Energy's smart meters against ANSI standards C12.20 class 0.2[2]. UNR tested both smart meters and legacy meters removed during smart meter installation and established an independent reporting process for both new and legacy meter accuracy reporting. Published results have validated that the accuracy of both smart meters and legacy meters satisfies the ANSI standards.

Step 4 – Deployment

Utilities recognize the importance of regular communication with customers in advance of the installation of new AMI enabled electric meters and gas modules. NV Energy utilizes multiple methods of communications, as depicted in the following diagram.

[1] *Watthour Engineering Co., Inc.*
[2] *Refer to ANSI standard C12.20 for the specific accuracy standards required of each class of electric meter.*

NV Energy introduced the *NVEnergize* project to the public via a multi-media event. Media and civic leaders from throughout the NV Energy service territory were invited to learn first-hand about the project and were encouraged to share what they had learned in their communities.

NV Energy conducts targeted consumer communications prior to meter installations. Approximately 60 days prior to meter installation, NV Energy presents the concept of *NVEnergize* and its benefits to consumers scheduled for installation via community events and gatherings. Within 30 days of meter installation, NV Energy provides information to customers about the planned meter installation.

Approximately one week prior to meter installation, NV Energy calls each customer to inform them of the upcoming installation. Immediately prior to the actual meter installation, NV Energy's installers will knock on the door to notify customers that their meter is about to be exchanged. Finally, upon the completion of each meter installation, a door hanger is left with *NVEnergize* Resolution Center contact information. NV Energy developed specific processes to address installation issues, including how to handle installation rejections, field installation complications and consumer claims.

Following installation of a meter and/or module, NV Energy conducts a post installation survey to measure the satisfaction of customers with the meter installation process. A portion of all installations are field audited in accordance with preapproved installation specifications to ensure the quality of the installation and to identify any areas of needed improvement.

Step 5 – System Verification

To ensure confidence in the capabilities of the new AMI system, NV Energy employs a system verification process to demonstrate and document *NVEnergize* system performance. This system verification includes multiple steps and efforts.

Field acceptance testing verifies that the technical, functional, performance, informational, and commercial specifications of the AMI system proposed can be realized as expected. Additional field acceptance testing occurs as new elements of a system are introduced. Included in field acceptance testing is the verification of meter accuracy and of the accurate transmission of usage information via the AMI solution. Tests of functionality are conducted in lab facilities and at customer premises. Automated tests validate system performance metrics over time and include the comparison of manual meter reads with AMI obtained reads for all meters. NV Energy initially conducted field acceptance testing on a population of about 10,000 meters and has since expanded the automated testing of AMI system performance to a larger population to ensure scalability.

NV Energy continues reading AMI-enabled meters manually while comparing pre-AMI readings with AMI-enabled meter readings. Variances in usage between the two types of readings have been investigated and, to date, no smart meter accuracy problems have been identified.

Once NV Energy is satisfied that the *NVEnergize* solution accurately measures and communicates energy usage, NV Energy transitions meters from billing via manually-obtained meter readings to billing via meter readings obtained via AMI.

Step 6 – Customer Ownership

Once the customer is confident that the *NVEnergize* system is secure, private, accurate, and deployed properly, the customer is empowered to take on ownership of their energy consumption. Energy ownership is the sixth and final kind of performance required to achieve customer confidence.

Customer ownership is very different from the earlier steps as it requires the customer to take action. The utility must provide a set of tools that facilitate customer action and customers must be motivated to use those tools. The active use of these tools and the resulting energy ownership by consumers develops at varying paces over time.

NV Energy customers have access to the *MyAccount* customer portal which provides opportunities for energy education and enables various customer actions. To date, more than 50 percent of *NVEnergize* customers are active *MyAccount* customers.

What are other utilities doing?

Westar Energy
Includes a proactive community partnering effort in the public communications of SmartStar Lawrence and will utilize focus groups and surveys to validate the effectiveness of its messaging

City of Fort Collins
Implementing a multi-step communications effort during installation of smart meters

Baltimore Gas & Electric
Multi-phase communications plan incorporates varying channels to communicate in advance of its smart meter deployment

This means that they are already experienced at using the tools that NV Energy has made available to them. *NVEnergize* provides the ability to view load profile information, be alerted when various consumption activity occurs, and gain a better understanding as to how consumers' actions influence their energy usage. In the future, *NVEnergize* will introduce various demand response programs and Time Of Use (TOU) rates that test the tolerance for and effectiveness of various pricing signals on energy ownership.

Ultimately, NV Energy plans to verify the achievement of customer energy ownership via surveys and on-premises interviews.

Concerns

As demonstrated in California, Nevada and the City of Naperville, Illinois, a very small percentage of the consumer population can negatively influence the majority and force regulators to implement highly inefficient, "opt-out" provisions. To address this, utilities deploying smart metering systems should be prepared to adapt their consumer confidence planning to deal with potential "opt out" alternatives. This should include frank communications on the cost and benefit impacts of providing "opt out" alternatives for the select few consumers who might request it.

The communications plans should also include a focused educational process that proactively addresses the concerns of those requesting an "opt out" solution. Using such programs, utilities have shown that they are often able to assuage the concerns of some of these consumers.

Conclusion

As part of its open docket regarding opt-out in the state of Nevada, the PUCN investigated the privacy, security, and accuracy of the *NVEnergize* solution. The PUCN found that "information gathered in this proceeding supports that smart meters are safe, secure, accurate, and reliable"[3]. NV Energy has successfully deployed more than 700,000 smart meters to consumers and is realizing operational and customer benefits today. NV Energy's consumer confidence plan plays a key role in this achievement.

About the Author

Jeff Evans is an Executive Consultant at Black & Veatch. He has 20 years of experience in the utility industry with a primary focus on Smart Grid and AMI solutions. He holds a BS in Mechanical Engineering and an MBA in Marketing and Management & Strategy. Reach him at *EvansJ2@BV.com*

[3] *"Report on NV Energy's Advance Service Delivery Meter Program", PUCN Docket 11-10007, February 29, 2012*

Keeping the Lights on for Communications Systems: The Need for Improved Network Monitoring

By Ashish Singh, Global Product Management, GridMaven

For nearly a century, U.S. utilities have routinely managed complex energy systems to deliver safe, reliable power. In contrast, utility communication networks have been simpler. Even as telephone lines, fiber optics and advanced radio networks were added, they were purpose built and often based on low-bandwidth technologies that delivered relatively modest quantities of communications data. This is changing as utilities move forward with ambitious Smart Grid visions.

Many utility Smart Grid plans share common elements such as advanced metering infrastructure, advanced distribution management systems and distribution automation. The data needs of these different Smart Grid applications vary significantly, so utilities are deploying varied portfolios of two-way communications technologies across their service territories. Utilities are now among the largest users of privately owned and operated communications networks; their needs are increasingly being met by a variety of new and legacy technologies, including fiber optics, power line carrier and various licensed and unlicensed wireless spectrum.

Complexity Has Arrived

Several factors can affect the delivery of data across a network, including latency, packet loss, retransmission delays and throughput. Latency is particularly important for mission-critical applications and latency requirements for utility applications span a wide range: less than 10 ms for teleprotection, 20 ms for synchrophasors, 100-200 ms for SCADA and VoIP and 2-14 seconds for smart meters.

Utilities are finding that hybrid, heterogeneous communications networks are the norm, not the exception. For example, a utility may choose to build out a new RF mesh network for AMI but then tap into public cellular and existing fiber for backhaul purposes. Customers located at the edge of the service territory or in terrain that causes issues for RF mesh may require additional connection via cellular, satellite or another network. The utility may have legacy systems in place for SCADA and also have plans to enhance DA capabilities, which may require additional communications infrastructure.

Utility Smart Grid communication networks are like an orchestra in search of a conductor. Distributed autonomous devices ("nodes" in network parlance) route, gather, and process data in complex ways. Depending on the deployment architecture, each node may be able to communicate through other nodes to send information back to the network operators. Intermediate nodes may aggregate and cache data to reduce bandwidth usage for data transmission back to the utility. Some applications will be data-gathering, requiring network nodes to report data periodically to a collection unit. Some are event driven, meaning nodes only send data when an event of interest (e.g., a fault or exception) occurs. Many applications, particularly in control centers, are a hybrid of these two kinds.

As Smart Grid applications continue to grow, new networks may be added and new uses of existing networks will increase network complexity, bandwidth demands and performance sensitivity. To avoid possible disruptions of the grid system, a highly reliable, scalable, secure, robust and cost-effective integrated communications infrastructure is needed. Utilities must establish Quality of Service (QoS) metrics with their vendors and be able to monitor and successfully manage these requirements across devices from all networks in order to fully exploit the power of a unified network infrastructure.

The Multi-Network Monitoring Dilemma

Multi-vendor, multi-protocol, varied latency requirements-based Smart Grid communications systems are becoming common. This environment creates a host of management challenges. While any given utility will have specific requirements, there are basic components in managing any type of network.

1. **Network Planning:** Determining the optimal network set-up and planning for growth based on the underlying business case for which the Smart Grid network is being deployed and the requirements of the services that will use it.
2. **Network Security:** Ensuring data and applications are only accessed by authorized users and often ensuring standards compliance.
3. **Network Analysis:** Monitoring and reporting of key performance indicators in a network to give an overall view of network health, to document standards compliance and to aid in troubleshooting.
4. **Device Management:** Monitoring, updating or controlling specific devices on the network, or components of the network itself.

Managing multiple networks together as one system is not a simple task. Needing to manage networks across a variety of platforms can significantly increase operational expenses, not least of which is the cumulative cost of training personnel. Element management tools may be provided to manage each individual network but operators are still left with multiple silos that are not integrated. Some networks may even require management at the device level. Locating failures across multiple network management platforms is extremely difficult without both end-to-end provisioning and a unified performance monitoring mechanism. Troubleshooting across multiple networks is also complicated and requires high backend integration costs.

For example, a utility with a million meters may see up to one percent of those generating events and alarms daily. At 10,000 alarms per day, that is overwhelming even for a sophisticated Network Operation Center. However, many utilities lack alarm correlation techniques to determine the root cause of faults across different network platforms so fault restoration is often less than optimal.

Reactive problem detection can lead to longer communication outages, increasing the possibility of affecting power service. Insufficient information on how the network is used and uncertainty about how planned changes will affect the network and grid applications make network planning difficult and sometimes incomplete. Limited monitoring of network performance metrics also creates difficulty for operators to understand if vendor Service Level Agreements are being upheld. The need to maintain multiple maintenance teams of engineers hampers quick fault detection and has an adverse effect on the operator's OPEX costs.

The key challenges for utility network operators with multi-network management can be summarized as the following:

- High cost of training personnel across multiple management platforms and performing device management
- Reduced efficiency in identifying root cause of network faults and exceptions with siloed management systems
- Manually monitoring and analyzing large quantities of network health data becomes unsustainable
- Reactive-only maintenance misses opportunities to prevent interruptions and improve asset life

As intelligent devices are deployed en mass across a utility service territory, the communication infrastructure becomes more dynamic and complex. The need for a Smart Grid communications-focused network management platform is now even more critical than before. Utilities are renowned for their abilities to monitor and manage the power grid; this rigor and sophistication should be applied to utility communications as well.

Tapping Telecom's Transformation to Meet Unique Utility Needs

The telecommunication industry has undergone a similar dramatic transformation over the past decade and has leveraged the Telecommunications Management Network (TMN) protocol to deal with the challenges. This model has four layers: business management, service management, network management and element management, which in turn, cover a wide variety of management areas including planning, installation, operations, administration, maintenance, and provisioning of telecommunications networks and services. Utilities can benefit from this framework and extend the paradigm for the unique needs of managing Smart Grid networks. However, the challenge is to apply an inherently hierarchical TMN architecture to a wired and wireless multi-vendor, multi-protocol, varied latency requirements-based Smart Grid communications system.

Figure 1 captures the process flow for Smart Grid specific network management.

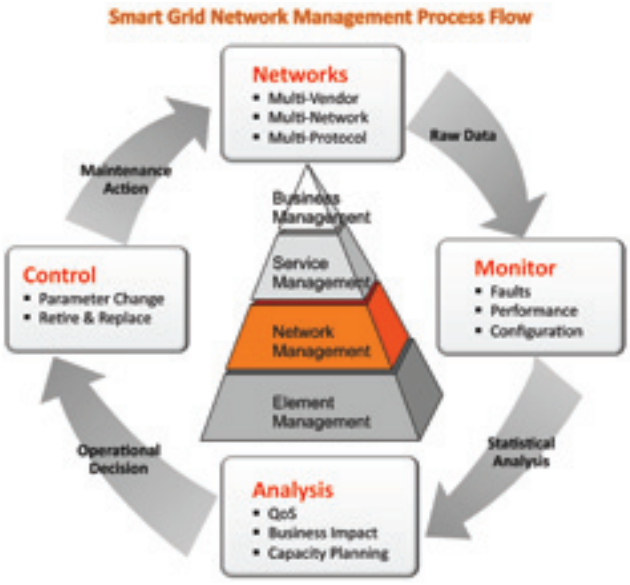

Figure 1

Utilities have unique communications needs and require management tools that address:

- Performance and fault management recommendations specific to Smart Grid networks. For example, for an RF mesh network, relevant statistics might include hops per router and range per node.
- Interworking functions between various segmented networks managing different latency-based service requirements. For example, incorporating data from an AMI network into an OMS system.

- Performance objectives and procedures for utility communication networks. Utilities' objectives may be impacted by regulators and consumer advocacy groups.
- An end-to-end view of entire system performance to better understand reasons for business service impacts. For example, if an operator does not receive confirmation that a control signal was delivered to backhaul network device, s/he will want to pinpoint where faults occurred throughout the entire system that may have caused an interruption.
- Management of differentiated QoS guarantees for different network uses. The same network may have more than one use, for example, backhaul for AMI and DMS. Operators will want to monitor and manage different QoS metrics for each application.
- Combining legacy systems (e.g., SCADA), which may be decades old but with newly deployed networks. Fully integrated management of a utility's communications infrastructure requires visibility into all networks.

The Next Wave of Management Tools

Traditional element and network management solutions often do not allow network administrators to keep pace with the size and complexity of Smart Grid networks. The latest tools for utility communications take a centralized approach to monitoring. This new method goes beyond managing just one network or one type of network technology, such as wireless networks, to view the entire communications enterprise via a "single pane of glass". In some ways, this new approach mirrors the way utilities have always monitored the flow of electrons – real-time monitoring of multiple, disparate applications and systems.

GridMaven's Network Manager, developed by the utility division of SK Telecom Americas, centrally monitors RF Mesh, cellular, PLC, fiber, satellite or any other network a utility may use. This approach, developed though years of operator experience, embodies the new breed of tools which help utilities to not only maintain networks but to fully leverage their communications infrastructure to capture increased business benefits.

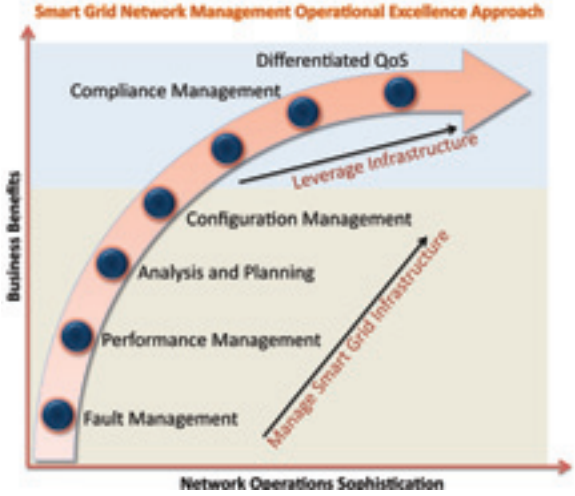

Figure 2

A centralized Smart Grid 'Manager-of-Manager' platform provides the necessary tools for rigorous and sophisticated network management by extending key TNM concepts and adapting them for Smart Grid networks. The platform can provide a complete end-to-end view of the system health and fault and performance data from different network elements.

Such a platform will not replace individual tools provided by vendors who build out utility communications systems but rather augment their usefulness. It will sit atop the communications ecosystem and gather data from element management systems and directly from network devices, if necessary. The platform should also incorporate policy, or rules-based, management functions. Operators set a course of action to be followed for a specific network issue or combination of issues across the system. This ensures standard procedures are followed and decreases likelihood of service disruption.

In general, utility network operators will see the following business benefits from using a centralized management platform:

- Meet QoS expectations through end-to-end service visibility
- Optimize network resources to improve performance and quality
- Cut network operating costs
- Support network planning process to roll out more Smart Grid network services
- Expedite Smart Grid network diagnostics

Operationally, the key benefits for network operators can be grouped into two categories, as shown in **Figure 3**.

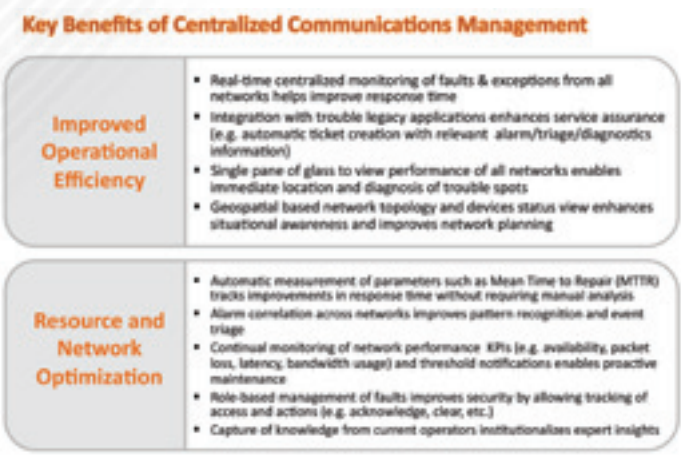

Figure 3

Whether network operators want to undertake a quick network diagnostic, develop a detailed backhaul network upgrade or validate an existing network SLA and QoS, such a technology will support the business in clarifying its Smart Grid goals and objectives.

Fulfilling the Promise of a Smarter Grid

One of the visions of the Smart Grid is to optimize asset utilization and increase grid operation efficiency. Tools that can help bridge the gap between IT and telecom operations are crucial to helping utilities achieve their plans. The availability of centralized grid communications intelligence will give management, planners and engineers the knowledge to build what is needed when it is needed, extend the life of legacy assets, repair equipment before it fails unexpectedly and more effectively manage the communication system that is becoming the intelligence of the Smart Grid.

About the Author

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THE BIGGER PICTURE

BY GREGORY K. LAWRENCE, CONTRIBUTING EDITOR

Generation Investors Step Up to the Plate: What's FERC Pitching?

Existing and planned electric generation faces important headwinds to profitability and financing given lower electricity and capacity prices, a slow economy dip in demand, looming "big-ticket" capital expenditures such as environmental regulation compliance, and competition among generators based on fuel sources. Renewable generation is in a lull absent renewed federal tax credit and grant programs. Forward curve price signals for generation repowering and new construction are not yet perfectly clear.

Facing such uncertainties, the need for capital investment in the power generation sector may be at its highest. And investors come in all shapes and sizes – banks, hedge funds, private equity – each with different risk profiles, passive or active management plans, and expectations on returns. Each targets different opportunities ranging from the profitable to distressed, from single plants to the restructuring of entire fleets. Many generators are regulated as "public utilities" by the Federal Energy Regulatory Commission ("FERC"), while and many interested investors are not familiar with FERC's asset disposition and affiliation rules – rules that directly impact the investment structure and expectations. Is FERC clearing the way for generation investors or throwing curve balls?

Assuming investors are willing to step up to the plate, navigating FERC's requirements is a gating issue. As a regulated industry, advanced approval often is required before making investments in "public utility" assets, including independent power producers. As discussed here, FERC has made progress in facilitating such investment through the institution of "blanket authorizations" that obviate the need for investors and generators alike to obtain FERC pre-approval for the purchase and sale of smaller minority interests in the generator. FERC, however, has been cautious. For example, one blanket authorization rule that would arguably provide the investment community with needed additional flexibility has been pending since January 2010, with case-by-case review continuing in the interim.

I. Background Regarding FPA Asset Disposition and Acquisition Requirements

The Federal Power Act ("FPA") requires prior FERC authorization for certain mergers, dispositions and acquisitions involving electric generation and transmission companies and their upstream holding companies. Generation and transmission companies are often deemed "public utilities." Section 203 of the FPA requires prior FERC authorization for a public utility to:

- sell, lease, or otherwise dispose of the whole of its facilities;
- sell, lease, or otherwise dispose of any part of its facilities of a value in excess of $10 million;
- merge or consolidate its facilities with any other person;
- purchase, acquire, or take any security in excess of $10 million of any other public utility; and
- purchase, lease, or otherwise acquire an existing generation facility in excess of $10 million.[1]

Certain holding companies also must obtain FERC approval under section 203 before acquiring more than $10 million in the securities of any transmitting utility, electric utility, or any holding company that includes a transmitting utility or electric utility. [2]

Under FERC's definition, an investor is an "affiliate" of a public utility if it owns, controls, or holds with power to vote 10 percent or more of the public utility's outstanding voting securities. The public utility is also considered to be an affiliate of the investor, as are any companies under common control.[3] Under FERC's regulations, owning, controlling, or holding with power to vote less than 10 percent of the outstanding voting securities of a specified public utility company creates a rebuttable presumption of lack of control.[4]

FERC analyzes the disposition of the ownership of public utilities including jurisdictional generation assets under FPA § 203. FERC must ensure that the transaction will be consistent with the public interest by reviewing the transaction's effect on competition, rates, and regulation. The transactions also cannot "result in cross-subsidization of a non-utility associate company or the pledge or encumbrance of utility assets for the benefit of an associate company" unless found to be consistent with the public interest."

[1] *16 U.S.C. § 824b (2006).*
[2] *Id.*
[3] *18 C.F.R. § 35.36(a)(9) (2009).*
[4] *18 C.F.R. § 35.36(a)(9)(v) (2009).*

II. Existing Blanket Authorizations Applicable under FPA Section 203

FERC has issued generic "blanket approvals" applicable under FPA § 203 for certain classes of transactions. For example, FERC has granted blanket authorization for acquisitions and dispositions of less than 10 percent of the outstanding voting securities of a public utility (including generators), and has declared as a matter of general policy that a transfer of less than 10 percent of a public utility's outstanding voting securities is, without additional indicia of control, not considered a "transfer of control" for the purposes of § 203.

FERC also has granted project- or transaction-specific blanket authorizations on a case-by-case basis.

One example of a transaction-specific blanket authorization came in 2009, when Franklin Resources, Inc. ("Franklin") and its investment management subsidiaries and applicant funds ("Franklin") requested blanket authorizations for each of its "Reporting Groups" to acquire up to but less than 10 percent of a publicly traded utility where the Reporting Group files a Schedule 13D (the "beneficial ownership report" under Security Exchange Commission rules) for such holdings.[5] The use of a 13D rather than a 13G (beneficial ownership report for passive investors and those not exerting control) filing would allow Franklin to assume a broader advocacy role with respect to major economic decisions and corporate governance issues, such as asset purchases and changes in management.[6] FERC allowed Franklin to treat each of its Reporting Groups as a separate entity, and granted Franklin's request to rely on Schedule 13D filings and certain conditions to establish Franklin's inability to exercise control over the utility whose securities were to be acquired.[7] FERC in that case granted blanket authorization for each individual Reporting Group to acquire up to 20 percent of the voting securities of a public utility or its parent, and imposed a limitation of less than 10 percent on the ownership of voting securities of a publicly traded utility by any applicant fund or investment account within the Reporting Group.[8]

FERC also has granted project-specific blanket authorizations. In general, these blankets authorization have been requested by specific generation projects seeking authorization to dispose of up to 20 percent of its upstream securities to certain investors not otherwise engaged in the energy business. A condition of these blankets has been that such investors not own 5 percent or more of another generation assets in the same control area. These project-specific blanket authorizations have been extremely helpful, yet given the 5 percent limitation on other investments in the same market, investors often become ineligible.

III. Proposed Blanket Authorization Rulemaking

In January 2010, FERC issued a notice of proposed rulemaking in response to the Electric Power Supply Association's ("EPSA") request for guidance regarding the concepts of "control" and "affiliation" as they relate to transactions subject to FPA section 203.[9] EPSA specifically requested that where an investor directly or indirectly acquires 10 percent or more but less than 20 percent of a public utility's outstanding voting securities and is eligible to file a statement of beneficial ownership with the SEC on Schedule 13G, such investment would not be deemed to result in a transfer of control so as to trigger the need for authorization under FPA section 203(a)(1) or to result in affiliation with the public utility under FPA section 205.

FERC proposed:

(1) to adopt blanket authorizations under FPA Section 203 for the acquisition of between 10 and 20% of the voting securities of a public utility or of a holding company with a public utility subsidiary by an investor, conditioned on the submission of an "Affirmation" regarding control; and

(2) to exempt such an investor and the affected company and its public utility subsidiaries from the definition of "affiliate" for the purposes of FERC's market power analysis, reporting requirements, and affiliate sales restrictions under FPA section 205.

Though FERC issued this rulemaking in early 2010, and many parties filed comments in support, FERC has not yet moved to enact a final rule and resulting regulations. FERC might be hesitant given the broad applicability that the blanket authorization contained in the rulemaking would have. Interestingly, FERC has issued authorizations to specific projects based on representations of non-control guided by the example affirmation found in the pending rulemaking.

For example, FERC recently authorized the acquisition of up to 20 percent of the equity interests in Entegra Power Group, LLC ("Entegra") by Merrill Lynch GENCO II, LLC ("ML Genco").[10] Because ML Genco also owned interests in another generation asset located in the same control area, it committed to transaction-specific covenants ensuring its lack of control over Entegra's generating assets. Among other things, ML Genco committed:

- not to take any action that directly or indirectly exerts decision-making over the sale of electric energy by the Entegra Project Companies, including any discretion as to how or when power generated by such companies will be sold;
- not to increase its aggregate holdings beyond 20 percent in Entegra, absent express prior authorization from FERC; and

[5] *Franklin Resources, Inc., 126 FERC ¶ 61,250 (March 19, 2001).*

[6] *Id. at ¶ 18. Investors who take over 5% of the total outstanding shares in a company must file either a Schedule 13G or a Schedule 13D. Schedule 13G is for passive investors or those who do not intend to control the company. Schedule 13D is for investors that might want to exert control. Schedule 13D also is for an investor owning more than 20% of the company, or if it intends to be active in company management.*

[7] *Id.at ¶ 31.*

[8] *Id. at ¶ 39.*

[9] *Notice of Proposed Rulemaking, Control and Affiliation for Purposes of Market-Based Rate Requirements under Section 205 of the Federal Power Act and the Requirements of Section 203 of the Federal Power Act, 130 FERC ¶ 61,046 (2010).*

[10] *Entegra Power Group, LLC, 136 FERC ¶ 61,049 (2011).*

- not to seek or hold representation on Entegra's board or the boards of the Entegra Project Companies;
- to make quarterly reports to FERC regarding the level of ML Genco holdings in Entegra and its continued compliance with the conditions. [11]

In addition to the rulemaking affirmation, ML Genco's commitments also are similar to a set of conditions FERC accepted in a prior authorization of the acquisition of up to 40 percent of the equity interests in MACH Gen, LLC ("MACH Gen") by Strategic Value Partners, LLC and funds under its management ("SVP").[11]

These specific grants and inaction on the rulemaking indicate that although FERC might be comfortable with transaction-specific blanket authorizations, it might have some degree of unease with respect to industry-wide grants given FERC's charge to ensure such transactions, including the ownership of generators, are consistent with the public interest. An investor's acquisition of the voting securities of a public utility could trigger the FPA section 203 authorization requirement for both the generator and the investor and create new affiliations between, and regulatory requirements for, the generator and the investor and its affiliates. This is a significant consideration for structuring the investment. Clarity and certainty regarding the rules can only help to reduce investor's risks and thus encouraged needed generation investment.

ABOUT THE AUTHOR

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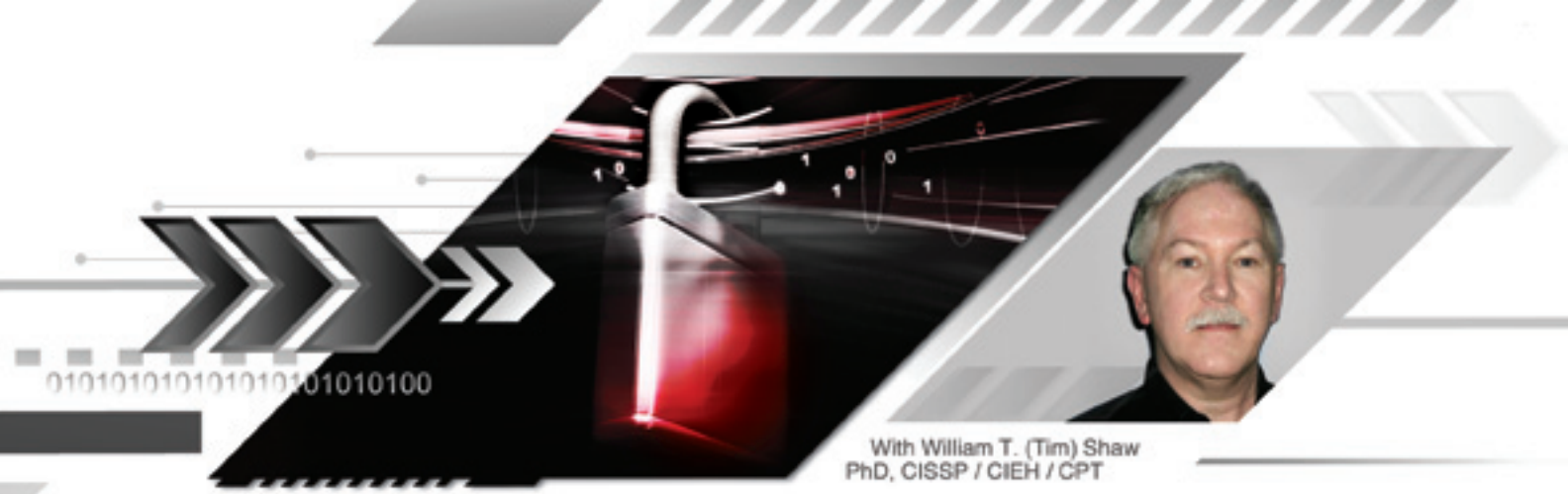
[11] *Id. at ¶ 18.*
[12] *MACH Gen, LLC, 127 FERC ¶ 61,127 (2009).*



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

SECURITY SESSIONS

Ahoy! Thar' she blows!

Welcome to the latest installment of Security Sessions, a regular feature focused on security-related issues, policies and procedures. In prior columns I have discussed some of the various threats to our critical infrastructure automation systems and ways in which exploitable vulnerabilities can be eliminated or at least mitigated. The problem is that all of the latest high-tech security toys and gadgets can be made ineffective because of poor employee training and bad security habits. The fact is, the two most prevalent ways for attackers to gain entry into our computer systems are by means of our email usage and the way we browse the Web. These days, most companies have developed (or purchased) personnel policies regarding proper email etiquette and have articulated the kinds of websites that can be visited on company time and using company equipment. These policies need to be kept updated to ensure that they address the ever-morphing methods used by attackers to exploit these tools. – ***Tim***.

In previous columns, I have stated that employee training and awareness programs can be one of the most effective tools for preventing successful cyber compromises and attacks. I firmly believe in that statement. Unfortunately too many organizations either figure that "IT" is responsible for cyber security, and so no one else needs to be involved; or they provide some level of one-time, lackluster training at the time an employee is hired, and then never again. If they have cyber security policies it is often left up to the employee to hunt them down and read them (although they will be punished for breaking them – always good to keep a small herd of scapegoats handy!)

Because of this, potential attackers are still able to use cheep tricks and social engineering ploys to prey on those organizations. Every couple of months it seems like the evil hacker community devises yet another strategy and technique to break into our systems. The latest worm to be loosed on the Internet makes the news. Some researcher publishes a list of new vulnerabilities identified in software we all use and depend upon. And yet these things are far less likely to be the basis for a cyber compromise than the lack of proper cyber security training and having good security-related procedures.

A few years back many of us received those badly written and misspelled letters from people in Nigeria offering to wire a bazillion dollars into our back accounts if only we could provide them with the banking information. I guess some people actually fell for those amateurish scams. Today people receive emails purporting to be from their own bank or brokerage firm claiming to need account information and passwords verified. These emails usually include the correct corporate logos and have undergone spelling and grammar checks. They are far more professional then those creepy letters, but no less fake, and many people fall for them and reveal personal information that results in identity theft, or at least an empty bank account. Those 'phishing' scams are not specific or directed. You may get one even if you don't do business with the bank or brokerage firm in question. They go out in a shotgun manner to every email address the attacker can get their hands on.

A far more dangerous form of phishing, and one that may be used against your organization, is called 'spear phishing'. This is when the attacks are directed at a specific set of people and incorporate specialized information that gives them a semblance of authenticity. An example might be an email that arrives in an employee's in-box that has your company logo and is apparently from a company executive, including showing his/her photo, correct email address and phone number (available via public sources such as annual reports.)

The email might make mention of a recent event known to the employees (and probably made public in a press release.) The email includes a "link" to take the employee to a company web page with "important information". The odds are greatly in favor of the employee clicking the link and, as a result, getting malware injected into their browser, which then downloads and installs a root kit from the attacker's system. With some proper training and an awareness program, the odds can be reversed.

Another variation on the spear-phishing scam is something called 'whaling' where the targets of the pointedly focused phishing attacks are corporate executives. It is always interesting to see that in far too many organizations, the executives tend to feel empowered to ignore the very same policies and procedures to which they insist that their employees adhere. In some cases they just expect the IT folks to ensure that nothing bad can happen, so they don't have to worry about 'that cyber security stuff'.

Having been a C-level executive in the past, I realize that there are many demands on your time and that you constantly have a full schedule. Taking time to review and refresh yourself on good cyber security practices is just one of the things demanding your attention. But because of this – and the strong likelihood of being able to find a lot of public information about corporate executives – those executives tend to fall for phishing scams at a rate that is much higher than among their employees. Better still, from the viewpoint of the attacker many executives are lax about keeping their computers properly updated and virus scanned, and their own IT groups don't tend to press the issue. Similarly, their computers may be given broad access in the corporate network and probably can access systems containing financial information, personnel information and corporate intellectual property. In other words, the perfect place for a cyber attacker to establish a beachhead!

As with email, there are similar and related issues regarding web browsing. Aside from the fact that employees shouldn't be messing around on the Internet when they ought to be working, there is a distinct possibility of letting an attacker establish a beachhead in your corporate network if an employee goes to questionable web sites. On-line gambling and pornographic web sites are well known to be major sources of cyber infection. Just by visiting such a site an employee's computer could be infected with a root kit or other malware. Worse, there are web sites that appear fully legitimate but that exist mainly to infect visitors with root kits and add them to huge networks of similarly infected computers around the world (so called 'botnets' or 'zombie networks') controlled by organized crime. If employees understand the implications – and the consequences – of unsafe web browsing, they are less likely to engage in such activity.

In most organizations the computers of employees will be behind a corporate firewall that 'hides' them from the Internet using a technique called network address translation, or NAT. It is actually quite difficult to find and attack those computers from across the Internet. It usually requires going through a series of attacks, starting with your Internet-facing systems (i.e., email and web server) and then digging deeper into your company network. But if you make an outgoing connection to another computer out on the Internet, by browsing to them or clicking on a hyper-link in an email, you establish a communication session that can be exploited. I like to describe this using an old myth about vampires. That is, they can't enter your home unless you invite them in, but if you do invite them in, you are likely to be bitten. The same is true with malicious web sites.

Employees need to know about phishing and spear phishing and whaling attacks and about evil web sites. Knowledge is power, and they can use that power to avoid being the 'dumb schmuck that let hackers into our network.' Of course, there are technical mechanisms and tools that can be used to reduce the likelihood of bad things happening even if an employee DOES fall for a phishing scam. But they cost money, require IT support and maintenance and are far from perfect. A little employee cyber security training might be a more cost-effective solution.

Another subject that needs to be part of comprehensive employee cyber security training is an understanding of social engineering techniques, of which spear phishing and whaling are just two examples. But that will have to be the subject matter for a future column... ***Tim***.

ABOUT THE AUTHOR

Dr. Shaw is a Certified Information Systems Security Professional (CISSP), a Certified Ethical Hacker (CIEH) a Certified Penetration Tester (CPT) and has been active in industrial automation for more than 35 years. He is the author of *Computer Control of BATCH Processes* and *CYBERSECURITY for SCADA Systems*. Shaw is a prolific writer of papers and articles on a wide range of technical topics has also contributed to several other books and teaches several courses for the ISA and participates in several committees. He is currently Principal & Senior Consultant for Cyber SECurity Consulting, a consultancy practice focused on industrial automation security and technologies. Inquiries, comments or questions regarding the contents of this column and/or other security-related topics can be emailed to *timshaw4@verizon.net*.

Guest Editorial

Are Third-Party Energy Providers Changing the Consumer-Utility Relationship?

By Matt Dinsmore, Energy and CleanTech Practice Lead
Altman Vilandrie & Company

If Smart Grid 1.0 was focused on installing the automated meter reading (AMI) infrastructure, Smart Grid 2.0 is all about the products and services that are imagined, developed and marketed to consumers, changing the traditional relationship between utilities and their customers. Utilities will become more customer-centric and actively engage and empower their customers with more information about their energy usage, the actual cost of that energy and new tools to better manage their consumption. But what if instead of utilities leading this transformation, it's already underway outside of the traditional utility ecosystem, leaving unrealized value on the table for utilities and consumers and actually distancing utilities from their customers instead of bringing them closer?

The reasons for utilities to transition to Smart Grid offers are many, complex and often interrelated. They include:

- Increasing the percentage of renewable resources;
- Increasing cost of centralized generation;
- High cost of meeting peak demands;
- Cost of replacing an aging infrastructure that requires significant upgrades; and,
- Managing the impact of new technologies such as distributed generation and electric vehicles.

These are multi-dimensional issues that require a well thought out transition involving the utility, the regulators and consumers. However, what if this transition is already underway and being driven by parties from outside this well established paradigm? What if consumers were actively engaged by new technology and offers that appeal to their needs in ways that don't align with broader industry goals? How might these third-party services impact or erode demand with little visibility or control by utilities left to react rather than act? This has happened before in many different industries and may already be happening in the energy ecosystem.

Two of the best examples of this change happening outside of the utility purview are Nest and Solar City.

Many utilities have offered some form of thermostat or load control program to tie the consumer into programs such as demand response (DR), a critical peak pricing program (CPP), or energy efficiency campaigns. The utility (or third-party aggregator) plays a very important role in this program and incorporates this additional information and control into the supply-side of the business to drive efficiencies and share the resulting value.

For example, during a DR event, when the cost of power is at its highest, the utility either cycles off the AC or adjusts the thermostat, resulting in real savings. A portion of this savings is passed to the consumer usually in the form of a rebate or bill credit. The utility has visibility into the end load and makes decisions accordingly.

However, what if innovation occurs outside of this ecosystem? One of the more interesting energy products to come out in a long time that supports such a case is the Nest, a "learning" thermostat developed by former Apple employees that uses a combination of algorithms, motion detectors, internet connectivity, a web portal and an easy-to-use interface. The value proposition to a consumer is very straightforward: it is easy to use, will save you money, looks good on your wall and keeps you comfortable.

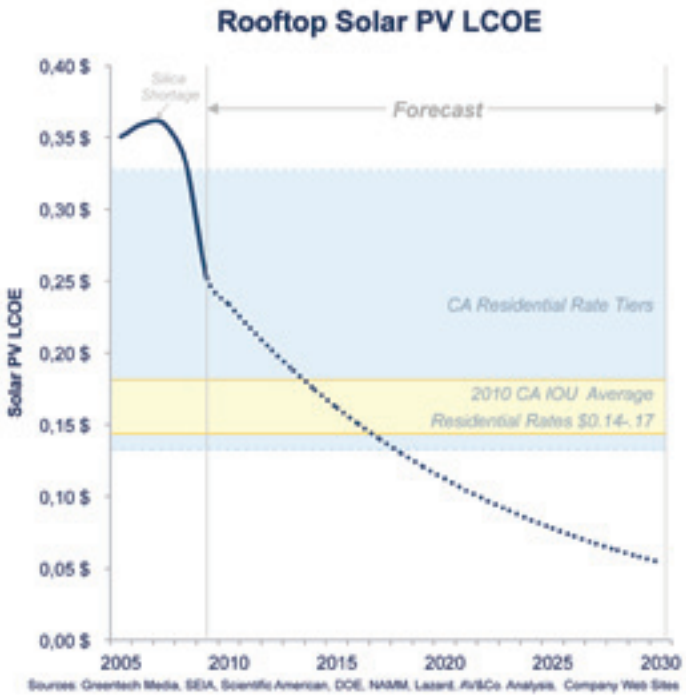
If Nest is successful, this could result in a significant number of higher usage customers (i.e., those with the income and usage to save enough to payback the initial cost of the Nest – think segmentation!). This would allow customers who dramatically change their usage and load profile to do so at will, and with the only indication given to utilities being lower usage and reduced bills.

This usage isn't tied into any of the EE or DR programs, leaving potential operational benefits and value on the table for all parties. The consumer interfaces with a specialized website, a downloadable iPhone app and a Nest thermostat, but not the utility. Nest has innovated around the in-home consumer energy experience and changed the energy relationship. I should tell you that I am a Nest customer myself, and in the first month with the device, I saved approximately 20% on my heating bill.

Are Third-Party Energy Providers Changing the Consumer-Utility Relationship?

Another example of this change is Solar City and its residential photovoltaic (PV) program. Again, a very straightforward value proposition: save money, combined with an innovative business model that removes the upfront cost barrier. This has led to significant customer engagement and surging subscribers. While there are certainly regulatory incentives that facilitated this market (e.g., feed-in tariffs and subsidies), it's clear there has been traction for this offer.

As with Nest, the consumer relationship is with a new player, Solar City. As rates continue to grow, residential PV becomes an economically viable alternative for more consumers, which drives scale and reduces cost. In turn, PV is economical for more customers – a very typical technology adoption cycle. In some states, such as California, this trend is magnified by high rates, high subsidies, feed-in tariffs, and an excellent solar resource (i.e., lots of sun). Therefore, the kWh cost of these models is becoming more economical. (See chart)



Consumers are making the decision based upon what is best for them, forcing the established utility ecosystem to react. Mass adoption of PVs certainly brings with it many benefits, but there are also implications to the established ecosystem. For example, high-use customers may be the most likely to move to this form of alternative power, reducing the aggregate consumption base over which the cost of the T&D infrastructure is levelized, driving up rates for those still dependent on the traditional centralized power system. As with Nest, a portion of the consumer-energy relationship has evolved.

These issues are not unique to the energy industry. We have seen this type of change occur in another wire-centric industry, local voice. The incumbent provider – the phone company – had a local monopoly on its version of the "distribution grid", the local copper plant. Yet new technologies such as wireless proved to be incredibly disruptive to the historical model. Over a very short time, we saw a dramatic shift in the number of copper wires required by consumers. In this case, a new network, driven by technology and consumer preferences to be mobile, was literally created out of thin air. Is Distributed Generation (DG) – for which PV is one form – that "next" network?

We have also seen attempts by the wireless industry to control the customer experience on "their network" with modest success with new consumer services such as ring tones, games and music. Because there was limited competition, this consumer-mobile content relationship evolved slowly. This was not because consumers didn't want the services, but rather because they were not being provided in a way that consumers wanted. Along came Apple and its competing ecosystem of iTunes and the iPhone. Now almost all mobile digital content is delivered through third parties like Apple, the Android app store, the Kindle store, the Nook and others.

The challenge for the existing ecosystem is not how do we drive this change. Rather, it is how do we create an environment that enables change so that consumers get what they want, and delivered in a way that contributes to solving the real world problems that the industry is facing. We need to allow more market forces into the ecosystem, but in a way that protects the historical utility investments and consumers.

Conclusions

If we want PV and DG, we need to move away from a variable cost recovery mechanism (kWh) for a fixed asset – that is, the transmission and distribution grid – perhaps a fixed fee for connectivity that varies on total potential load could work.

Are Third-Party Energy Providers Changing the Consumer-Utility Relationship?

If we want to avoid the lost value of utility disaggregation in the home, we need to make the meter data available to those parties the consumer selects and let creativity and innovation flourish in the home while still providing the visibility to the utility to maximize the value on the supply side as well as the demand side.

ABOUT THE AUTHOR

Matt Dinsmore is a director at Altman Vilandrie & Company and leads the firm's Energy & Clean Tech practice. He has over 18 years of experience building, growing and advising companies in the energy, telecommunications and technology industries. Matt has extensive experience in customer engagement, technology evaluations, demand assessments, new product development, business case development and go-to-market planning. Matt is a frequent speaker on Clean Tech and the Smart Grid at industry events, was the primary author on the Smart Grid Consumer Collaborative Excellence in Customer Engagement Report, and served on the Board of Advisors for Xcel Energy's Smart Grid City in Boulder, Colorado. Matt holds an M.B.A. from the University of Chicago Booth School of Business and a B.S.B.A from Washington University in St. Louis.

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