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SEPTEMBER 2011 Issue 6 • Volume 15

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Electric Energy T&D MAGAZINE

page 35

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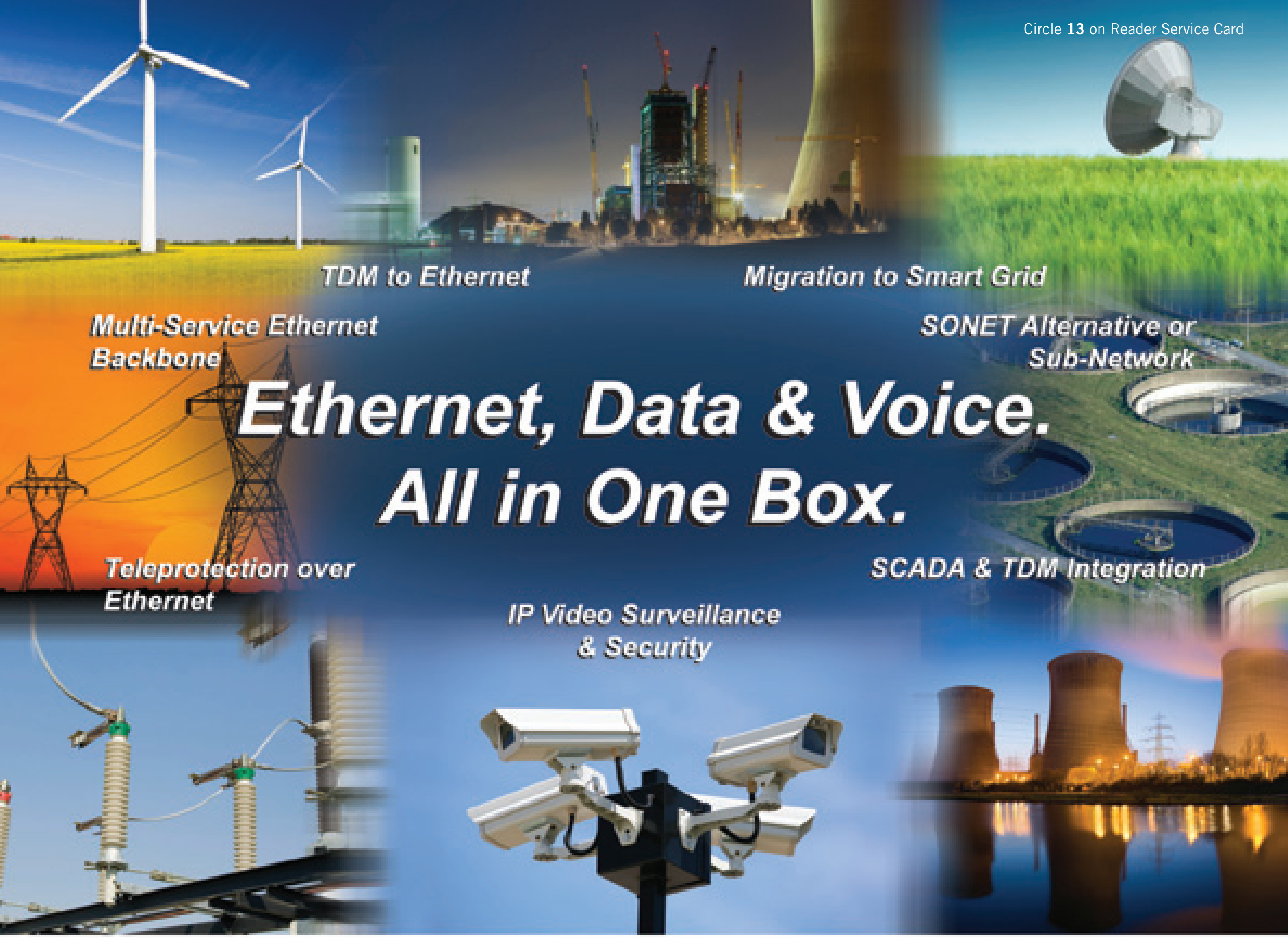

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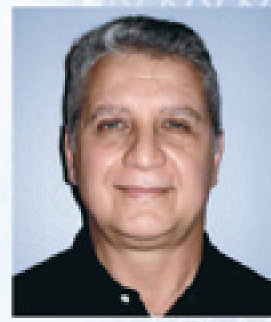

Energy Efficiency: Let's Just Do It!

We've been hearing and reading (and talking) about load control and demand response quite a bit over the past several years. Hardly a day goes by that DR doesn't make the headlines in one context or another. And then there's the technology – oh, so much technology! There must be at least a gazillion ways to curtail demand out there these days, give or take a few. But here's what worries me: Even with all of the energy efficiency measures and technology available, why do we still not seem too serious about doing something substantive about demand, and why does it seem like we aren't willing to spend and/or sacrifice anything to get it under control? So far, I haven't observed a deep commitment to demand reduction on a national scale, and I can't help but wonder why that is the case.

The fact is, DR is still an evolving business, and I'm not sure that anyone has found precisely the right balance between the pluses and minuses yet. Despite there being several of what I'd call serious DR suppliers, none of them seems to be setting the world on fire. Is it just that DR is not the panacea that some people claim it is, or is this yet another one of those things that hasn't been properly explained to the marketplace? Personally, I'm betting on the latter, and here's why...

Way back in 2007-2008 – before the recession became the #1 topic of discussion – we saw a lot of commentary about load growth, transmission congestion and the direct and indirect environmental impacts of future demand – all of which are as valid now as they were then – but these days we don't hear much about those issues. Why is that? Well, I believe that there is a very good reason. Notably, as the economy sagged, so did load growth. So naturally, being the 'farsighted' kind of folks that we are, we immediately developed a case of amnesia. We conveniently forgot about all of those down sides to meeting demand using conventional methods and quietly moved on to other pertinent issues of the day. (See, there are actually some positives out of this financial malaise!)

While the old adage 'ignorance is bliss' may be applicable here, don't think for a minute that the current situation will last. Be assured that along with economic recovery will come a return to load growth – you can depend on it. That is, as business ramps back up and energy use starts to rise again, energy demand will inevitably increase right along with it. And, when – not if – it does, those pesky problems with generation shortfalls, transmission congestion and environmental issues will be right back in our collective faces. Yep, déjà vu all over again! The question is, what are we going to do about it? Let's quickly review our options…

One thing we can do is build more generation. We still have lots of coal, which is the bulwark feedstock for a sizeable portion of existing power production. Nah, too dirty, you say. Okay, how about shale gas? The jury may still be out on that one, but early assessments of the pollution potential don't look so good, and it will definitely take some time (that we don't have) to sort it all out. Fuel oil? (More foreign oil!) Natural gas? (Hey, can you predict gas futures?) And then there's the renewables angle. Wind? Solar? Maybe as supplementary resources, but because of intermittency, there still has to be a base load capacity that will fill in the blanks when the wind doesn't blow and the sun doesn't shine, which as we all know, occasionally happen. Nuclear? Well, I'll let you figure out the chances of that happening in the near-term for yourselves.

But let's just assume for now that we figure out this pricey and exceedingly complex generation debacle, whatever the selection or mix turns out to be. What about those transmission lines that are at capacity and already straining to even handle present-day loads on a hot day? Now that we've all had some time to think about it, are we suddenly okay with siting and building new transmission lines – in YOUR backyard? How about in the Adirondack Mountains? Or, perhaps through the Mohave Desert? How about across Martha's Vineyard? Are those or similar alternatives somehow more palatable now than they were only a few years ago? I'm gonna go out on a limb here and assume that the answer isn't 'no' – but more likely, hell no! Understandably, almost no one wants to volunteer their personal property or put aside their protective instincts concerning the Great Outdoors, merely for the privilege of keeping the lights on, right?

Okay, that's admittedly a tongue-in-cheek question, but in fact, that's pretty much what it comes down to when you really think about it on the basis of the cold, hard facts – which by the way, are even colder without power! Obviously, we don't want to stop the economic recovery, but we also don't want our lights to dim or go out. So what to do?

Here's the good news: We already have several effective ways to deal with this problem. Categorically it's referred to as Energy Efficiency. Regardless of how you choose to engage in energy efficiency or which company you select to carry out your EE strategy, the net result is saving energy. And in the process of doing that we also get the additional benefits of fewer plants required (regardless of the fuel being used); fewer transmission lines needed to transport the power; and diminished negative impact on the environment.

At the end of the day, meeting future demand is OUR collective responsibility, and fortunately, we have measures we can employ that don't involve breaking ground on new generation plants, building new transmission or polluting our environment. Whether you call it Energy Efficiency, Load Management, Demand Response or something else, as the famous Nike slogan says, let's *Just Do It!* – ***Ed***.

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INDUSTRY NEWS

DTE Energy Launches Home Energy Report Pilot Program to Stimulate Residential Energy Savings

Detroit, MI, September 2011 - DTE Energy recently launched the Home Energy Report program, an energy efficiency program designed to help residential customers save money. The pilot program gives consumers information about their energy use so that they can make informed choices about their energy usage.

In July, DTE Energy mailed the detailed information about household energy usage to 50,000 randomly selected customers. It was the first of several reports that select residential customers will receive, that show individual home usage over time. The reports anonymously compare household energy usage with homes of similar size and makeup in their neighborhoods.

The Home Energy Reports provide customers with customized no-cost, low-cost and long-term energy efficiency options, by taking into account individual housing details such as age, size and type of homes. The reports also allow residential customers to make energy-reduction choices and track the effectiveness of their energy saving steps over time.

“The program has proven to be extremely effective, as it gives our residential customers a meaningful understanding of their energy usage,” said Vicki Campbell, Director - Energy Efficiency with DTE Energy. “By providing the tools customers need to save energy and money, the Home Energy Report Pilot Program is one more way that DTE Energy is serving its customers and community.”

DTE Energy is working with Opower to administer the Home Energy Reports program. Opower is an energy information company that uses behavioral science and targeted communications to motivate customers, increase engagement and verify sustained energy savings.

According to DTE Energy, the program is expected to deliver between 1.5 and 3.5 percent in average energy savings to utility customers. In fact, by mid-2012, DTE Energy is on track to save customers $1.2 million in energy bills. This is the equivalent of taking 1000 homes off of the grid.

“In (my) opinion, the home energy report is fantastic,” said Gerry Roston, a DTE Energy customer in Saline. “It provides customers with a solid understanding of their actual energy usage. Comparisons to comparable situations is the best metric there is.”

DTE Energy plans to expand this program to other customers over the next few years depending on the success of the initial pilot. For more information on how to save energy, please visit dteenergy.com/saveenergy

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ISO New England proposal includes continued participation of behind-the-meter generation in region’s electricity markets

FERC Order 745 compliance filing seeks full integration of demand resources

Holyoke, MA, September 2011 - In compliance with the Federal Energy Regulatory Commission’s (FERC) Order 745 on demand-response compensation in competitive markets, ISO New England has filed proposed market rules that will result in full integration of demand resources into system operations and energy markets by June, 2015.

Behind-the-meter generation will continue to be eligible to provide demand response in New England if the proposed rules are accepted by FERC. The ISO believes its proposed market rules would comply with all aspects of FERC’s Order 745, Final Rule on Demand Response Compensation in Organized Wholesale Energy Markets, and would treat demand-response resources fairly and on a comparable basis with other resources.

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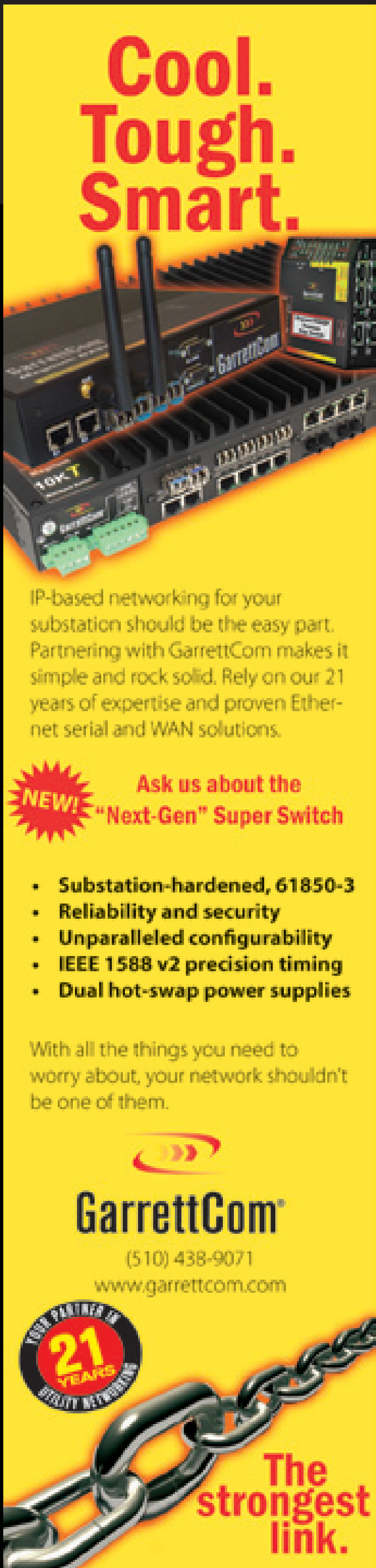

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INDUSTRY NEWS

The ISO proposal calls for a transition period that would allow the region to continue to offer, with some revisions, the existing programs that allow demand-response providers to participate in the region's energy markets. The transition period would end in 2015, when proposed rules for full integration of demand resources would take effect. ISO New England's proposal is subject to FERC approval.

ISO New England has had a long commitment to demand-side resources. The ISO's first demand-response programs were implemented in 2001 with 63 megawatts (MW) participating. Currently almost 2,800 MW of all types of demand resources, including energy efficiency, are available in New England. And through the Forward Capacity Market, almost 3,600 MW of demand resources will be available in the 2014-2015 timeframe.

An article detailing how behind-the-meter generation would participate in the region's energy markets under ISO New England's proposal has been posted on the ISO's news website at www.isonewswire.com.

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AEP Ohio Debuts First Lithium-Ion-Based Community Energy Storage (CES) System in the World

CES units from S&C provide electric backup during power outages

Columbus, OH, September 2011 - AEP Ohio, a unit of American Electric Power (NYSE: AEP), is taking the lead in testing a new energy backup system that will supply customers with electricity for a limited time during power outages. AEP Ohio begins the installation of the first Community Energy Storage (CES) system, designed to improve electrical reliability andbetter serve customers. This lithium-ion-based CES system is the first of its kind in the world to be installed at customer homes.

CES is a lithium-ion-based battery system that provides up to several hours of backup power during a power outage for customers who are connected to the CES unit. Each unit will power two to five homes. The exact amount of time the battery can provide power will depend on how much energy is stored in the battery at the time of the outage, and how customers connected to the battery use energy in their homes during the outage.

An average AEP Ohio outage typically lasts approximately two hours. Customers utilizing the CES unit who conserve energy during an outage may not experience any loss of power for the entire outage time. AEP Ohio plans to notify customers when their power has switched to battery backup.

"AEP Ohio is demonstrating a new and innovative technology to enhance our electric service," said Karen Sloneker, project director, gridSMART Demonstration Project, AEP Ohio. "As part of the project, CES units provide backup power to customers and allow AEP Ohio to charge batteries during off-peak periods and discharge them during high-demand times."

Sensing technology present in each CES unit recognizes when a home served by that unit loses electric power. When a power outage occurs, the CES battery automatically and rapidly begins providing power to the home via a transfer process that should occur without any impact on electric power quality. When AEP Ohio restores power to the affected homes, customers are transferred from the battery unit back to the electric grid.

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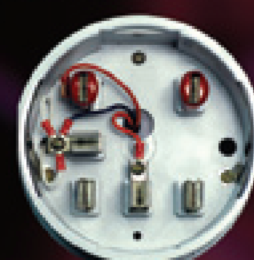

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AEP Ohio has a technology alliance with S&C Electric Company, which designs and manufactures the PureWave® CES units, adhering to AEP Ohio's specifications. S&C's IntelliTeam® Distributed Energy Management (DEM) system will also control and dispatch all 80 CES units planned for this project, allowing them to function as a virtual power plant.

"We are pleased to work so closely with S&C Electric Company," said Sloneker. "The company is contributing significant technological expertise to the AEP Ohio gridSMART Demonstration Project, which helps us offer customers greater energy control and improve electric distribution service and performance."

"We have worked closely with AEP Ohio from project conception through testing and development and are thrilled to see our CES devices installed in the ground in Ohio," said Jim Sember, vice president, Power Quality Products, S&C. "Our priority is building CES units to suit the utility industry's needs. AEP Ohio is the first of our customers to install these devices."

CES units are provided by AEP Ohio at no additional cost to the customer. In addition, customers who voluntarily agree to have a CES unit installed on their property will receive a $250 incentive.

The CES initiative is part of AEP Ohio's gridSMART® Demonstration Project – an initiative in a targeted geographic area that tests new technologies andconsumer programs that enhance reliability and a customer's ability to control their electricity usage. As part of the project, 80 CES units will be installed in the test area by the end of the year, and 30 of them are already scheduled for installation. In total, approximately 250 homes will have access to the CES technology.

There are two CES test locations in Gahanna. The first test location boundaries are Wendler Boulevard to the north, McCutcheon Road to the south, Big Walnut Creek to the east and Hines Road to the west. The boundaries for the second area includeGreys Market Drive to the north, Camden Passage Drive to the south, Appian Way to the east and Portobello Drive to the west. By limiting this test to a specific geographic area, AEP Ohio can quantify benefits for both the consumer and the utility itself. In addition, it allows AEP Ohio to easily review and assess usage data and make necessary adjustments. Depending on the results of this test and future equipment costs, AEP Ohio could plan to strategically install CES units throughout the utility's service area.

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Purdue Research Park Celebrates 50th Year

Indianapolis, IN, September 2011 - The Purdue Research Park is celebrating its 50th anniversary this fiscal year with events and programs highlighting the people and technologies that have contributed to the park's growth as the largest university-affiliated incubator in the country.

"Purdue Research Park set the gold standard for how universities can support economic development through business incubation and expediting new discoveries through the technology transfer process"

When established in 1961, the Purdue Research Park was the third such park established in the United States. Stanford Research Park was founded in 1951 and the Research Triangle Park in North Carolina followed in 1959. The Purdue Research Park now has four locations across Indiana and 200 companies that employ more than 4,000 people.

"This is a momentous year for the Purdue Research Park, and as part of our 50th anniversary we engaged an independent research firm to quantify our economic contributions to the state of Indiana," said Joseph B. Hornett, senior vice president, treasurer and COO of the Purdue Research Foundation, which manages the park network.

The study found that the Purdue Research Park network provides an annual economic impact of $1.3 billion to Indiana's economy.

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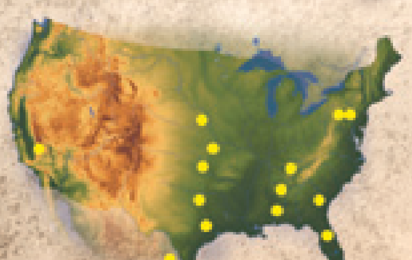

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"While it is important to recognize the economic contributions to the state, it is just as important to celebrate the international contributions the park and park-based companies have had on helping people by addressing global challenges such as health care, energy, terrorism and hunger," Hornett said. "The companies in the park network are doing work in nearly every sector, including engineering, life sciences, information technology, agriscience, security and advanced manufacturing."

Mitch Roob, Indiana Secretary of Commerce and CEO of the Indiana Economic Development Corporation, said the Purdue Research Park is a leader in job creation.

"Purdue Research Park set the gold standard for how universities can support economic development through business incubation and expediting new discoveries through the technology transfer process," said Mitch Roob, Indiana Secretary of Commerce and CEO of the Indiana Economic Development Corporation.

For example, Cook Biotech Inc. was founded in 1995 on a Purdue University discovery. Cook Biotech's regenerative biomedical products have been used in more than 1 million applications for patients around the globe. The company has about 140 employees and is a subsidiary of the Cook Group Inc.

"Celebrating 50 years is a major milestone for any organization, and being part of the Purdue Research Park is important for us because of the access to the brilliant faculty at Purdue University doing work in our field," said Mark Bleyer, president and CEO of Cook Biotech."

Endocyte Inc., another park-based company founded on a Purdue discovery, began trading on NASDAQ this year and raised more than $180 million for its research into the treatment of cancer and autoimmune diseases.

The company was founded in 1996 by Ron Ellis, president and CEO, and Philip Low, Purdue's Joseph F. Foster Distinguished Professor of Chemistry and chief scientific officer for Endocyte. Endocyte has about 65 employees.

"I travel all over the world and meet with other faculty and tour other research institutions. The assistance, support and other facilities provided by Purdue Research Park is unparalleled," Low said. "There isn't anything else like it in the United States."

Other examples of real-world contributions by Purdue Research Park-based companies include:

- M4 Sciences, a company that develops and commercializes advanced technologies for ultraprecision machining. The company's technology, which was developed at Purdue, was named by R&D magazine as one of the top 100 most technologically significant products introduced to the marketplace in 2010.
- Scale Computing Inc., a company recruited from the San Francisco area and based in the Purdue Research Park of Indianapolis, provides data storage for small- and medium-sized companies. In 2009 it was named by Forbes as one of America's Most Promising Companies.
- Energy Management Solutions, an energy monitoring and management company based in the Purdue Research Park of Southeast Indiana. In 2011 the firm received the Lugar Energy Patriot award from U.S. Sen. Richard Lugar for its research and contributions to energy conservation.

The Purdue Research Park has been recognized by state, national and international organizations. In 2010 the National Association of Business Incubators honored the Purdue Research Park Entrepreneurship Academy with the Incubator Innovation Award. In 2008 the International Economic Development Council presented three first-place awards for excellence in economic development in the areas of entrepreneurship, partnerships with educational institutions and technology-based economic development. In 2004 the Association of University Research Parks (AURP) recognized the Purdue Research Park with its top Outstanding Science and Research Park Award.

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FlexNet communicates with Sensus smart electricity meters, demand response and distribution automation (DA) devices to create a dynamic system that provides utilities with a complete smart grid solution to better measure, manage and control resources. In addition to meter reading, sensors placed throughout the grid enable rapid diagnosis of outages and the ability to remotely complete certain corrections.

The data transmitted via the network allows utilities to make more intelligent business decisions and manage efficiency of power distribution during peak usage times.

Demand Response and Home Area Networking
Combining HAN devices with the Sensus FlexNet system, gives utilities and consumers detailed energy usage information, flexibility and two-way communications.

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Distribution Automation
Distribution automation takes the smart grid beyond smart metering to manage distribution equipment and user access. Sensus delivers field-proven, end-to-end solutions that include software, hardware and network solutions such as the PowerVista™ application and intelligent field communication devices.

As a result, Sensus offers utilities the unique capability of segregating communications for DA within the FlexNet communications network while sharing the same infrastructure, an industry first. Unlike unlicensed systems that must share the same spectrum for DA on an AMI network, the FlexNet system can be partitioned for clear, unencumbered DA traffic.

The FlexNet system coupled with PowerVista ensures real-time access to distribution equipment from any computer through a secure account. FlexNet and PowerVista provide the communications network for utilities to detect, react and respond to system disturbances. Using the PowerVista application, personnel can quickly identify equipment or system issues remotely, even from the field.

The FlexNet solution with integrated SmartPoint™ communication modules provides interoperability with virtually all vendor distribution automation apparatus including switch controls, voltage regulators, reclosers, breakers, load tap changers, and other applications.

The devices support communication with DA assets and interface to utility SCADA or DMS systems for monitoring and control. The solution is compatible with legacy systems, industry standard network protocols, and existing and emerging DA technologies.

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A New Approach for Improving Demand Response Performance

By Michael Brown, Manager of Demand Response & Distributed Energy Resources, NV Energy and John Steinberg, CEO and Co-founder, EcoFactor

As the smart grid world unfolds with a plethora of new products, new services, new pricing schemes, and a lot of promises, discovering which of them are genuine and will facilitate improved customer satisfaction and value while delivering robust demand management solutions (and new jobs) is a pursuit deemed worthy of many billions of Federal dollars and venture capital. Debates ensue about how best and to what extent to enable customers to be demand responsive and energy aware.

Is that your generator calling – or a disgruntled customer?

How many of your traditional generating units have called into your customer service center to complain lately? While this probably has not actually happened, chances are that even after awarding rebate payments and free equipment, some of your mass-market demand response (DR) customers have called in with issues. And as virtual power plants that include customer resources expand, your call center representatives will need to be well prepared for fielding those issues, quickly and effectively.

Have you deployed load control receiver switches or programmable communicating thermostats? Have any of your customers claimed that your program damaged their equipment, or have any of them experienced "thermal issues"? What strategies will you use to help keep your new smart grid-enabled virtual power plants from calling in to the call center? They will have a big impact on your overall return on investment; especially given customer retention issues and the vast diversity found among distributed resources.

Portfolio Optimization

What are cost-effective and optimal portfolios of dynamic pricing and enabling technology offerings across various customer segments? One promising trend in the DR domain is to deliver more automated control and intelligence into the customer premise, while transitioning classic utility command and control systems for devices into forecasting, optimization, and strategic dispatching systems that can assimilate what many distributed devices have to offer at any given point in time. One expression of this concept is to provide mass customization to enhance customer value and satisfaction, while also delivering enhanced information and management capabilities. Where have you heard that before? That's right, you and a million other people bought something on the Internet… made just for you.

Can mass customization deliver value in the DR area? NV Energy (NVE) is testing a service that start-up company EcoFactor claims can provide automated and customized energy management. Properly implemented, such a service could potentially be used to enhance the mass-market appeal of utility customer programs, while also enhancing DR capabilities through better forecasting and improved dispatch strategy design and execution.

Demand Response: Then and Now

NVE has deployed mass-market DR programs over the years, utilizing a variety of technologies at scale from one-way receiver switches to two-way programmable communicating thermostats. Starting in 2007, NVE has ramped up its mass-market program from 20 MW to nearly 150 MW, utilizing primarily two-way programmable communicating thermostats. The thermostats are installed at no charge. Customers receive participation-based rebates, and can override DR events at the thermostat if they become uncomfortable during the typical one-size-fits-all four-degree setback events. The thermostats allow programming over the Internet and allow NVE to perform remote monitoring for strategic maintenance and measurement and verification.

NVE serves 45,000 square miles and 92% of the customers across the state of Nevada. But residential air conditioning load in the southern Las Vegas metropolitan area drives nearly 50% of a needle peak that reached 5,880 MW in 2008. Average temperatures at system peak are consistently above 104°F in the summer. (But as you know, it's a dry heat.)

So, it isn't too surprising that an actual customer enrolled in the thermostat program – let's call him Richard – keeps his thermostat set to 89°F during the summer to save money.

Richard called into the NVE call center in 2008 to complain about the standard four-degree setback. He said that by his measurements, his family and pets were able to tolerate a maximum of 90°F, but beyond that, NVE was putting the health and lives of his family in danger by running four-degree setbacks. Richard was reminded in a very friendly way that the program was a voluntary setback program and that he could override if he was hot. But that didn't go over so well, and he still demanded a program redesign to accommodate his individual needs and preferences.

Richard is one of the 20% of customers that have not (yet) expressed high satisfaction with the thermostat program. So, despite the fact that 80% of customers do express a high level of program satisfaction, and 80% of customers have very low memory recall of DR events – typically between 60-80 event hours per summer – there is still quite a bit of room for improvement. But exception handling is costly and time consuming. Deploying technology that seeks to increase the percentage of customers that don't even notice the events and don't perceive an interruption to their lives is one possible methodology in the tool chest to help improve customer satisfaction and program appeal.

Envelope Integrity vs. Program Goals

Some customers choose a summer set point of 74°F, so not only are there great disparities in customer comfort preferences, there are significant disparities in the thermal performance of homes. Some have extremely tight building envelopes that prevent inside temperatures from rising quickly. These homes have high load shed contributions, while other homes heat up quickly, which compromises load-shedding capability.

Four-degree setback strategies – though very convenient for the NVE load shape at the current program size – present limitations in system load shaping capabilities at higher program adoption levels. This approach delivers significant load shed early in a given event, but once a new thermal equilibrium is reached in the home at the higher set point, the air conditioner resumes cycling, and the load shed contribution for that particular home is greatly reduced. So, obviously technology and program goals are to find and invest in technologies that extend each particular home's load-shedding contribution with minimal customer impact.

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Pre-cooling is a natural candidate… but how much? End-use loads can be programmed to react automatically to electricity price levels within customer-defined parameters that represent acceptable tradeoffs between comfort and cost. Researchers have been working on this approach for years, but commercialization of these technologies has thus far been elusive.

A New Approach

In May of 2010, NVE learned that EcoFactor had been working to commercialize an automated service to reduce energy consumption based upon premise-specific conditions. The service treats each home individually, based upon its unique thermal properties, the current and forecasted weather, and the preferences of the home's occupants. The service combines data generated by two-way communicating thermostats with outside weather data sourced from the Internet to learn how each individual home and HVAC system perform under varying conditions; it then optimizes heating and cooling strategies based on that knowledge.

This optimization permits significant energy savings without requiring occupants to give up control or comfort, but what initially caught NVE's attention was the ability to individually optimize the way each home participates in DR events. The service not only applies pre-cooling strategies, but it can also customize those strategies based on each home's thermal profile. That is, the length and depth of pre-cooling can be adjusted so as to simultaneously improve the load shed contribution of each home while minimizing energy consumption and reducing the risk that customer comfort will be adversely affected.

NVE arranged to pilot the DR capabilities of this service during the summer of 2010 in the Las Vegas area. It was deployed to manage 25 thermostats in 16 homes. Each participant had previously opted into NVE Energy's two-way thermostat program, so pre-treatment A/C runtime data already existed. ZigBee communicating thermostats and ZigBee-to-IP gateways were installed in each location, and the gateways were connected to customers' broadband routers. Nine events were called during the period from August 24, 2010 to September 30, 2010.

The pre-cooling approach taken by the piloted service seeks to minimize both A/C cycling and discomfort by taking into account the thermal storage capabilities of each structure and A/C system, as well as the comfort preferences of the occupants. It automatically chooses pre-cooling strategies based on those constraints. However, it takes some time for the service to learn the thermal profile of the building, along with a series of calibration events.

Due to the late summer start and limited data set, definitive conclusions about the performance of the optimized pre-cooling strategies could not be drawn. This is largely because a larger data set is required to compare various objective functions of the optimization algorithms. However, based upon the limited observations, the service proved promising enough to expand the pilot to a larger sample population (80 customers in Las Vegas and 80 in Reno) to enable observations across the 2011 summer season. The calibration events alone demonstrated that various levels of defined pre-cooling strategies could rapidly be identified as potential offerings for various customer segments due to the robust data acquisition and reporting capabilities of the platform.

Cause and Effect

As expected, pre-cooling strategies applied in conjunction with a four-degree setback strategy increased the air conditioner idle time during the event window compared to the standard four-degree setback without pre-cooling. The piloted service also permitted consumers to adjust their thermostats at any time, including the ability to completely override DR events. Regardless of whether or not consumers opted out of event participation, yield was substantially increased across the population during each of the calibration events.

An example of how various levels of defined pre-cooling increased air conditioner idle time is shown in **Figures 1A** through **1D**. The figures graphically present A/C cycling performance and indoor air temperatures across four roughly similar days and various defined pre-cooling strategies. (These figures are for illustrative purposes only.)

Actual A/C runtime data is derived from the detailed data set, which includes data at 1-minute intervals. Thorough measurement and verification analyses will be conducted on the full data set after the summer 2011 season. The EcoFactor-enabled population will be compared to the overall thermostat population and various customer segments within it using weather normalization and regression analysis. It is clear from the sample figures that overnight and morning weather conditions impacted thermal performance; the optimization model exploits such variations in order to minimize energy consumption and maximize demand reduction during events given customer-defined constraints.

Figure 1A shows a normal day; the air conditioner cycles on and off throughout a typical DR event window (4-7PM) – during that period, it is idle for 57 minutes, or 31% of the time.

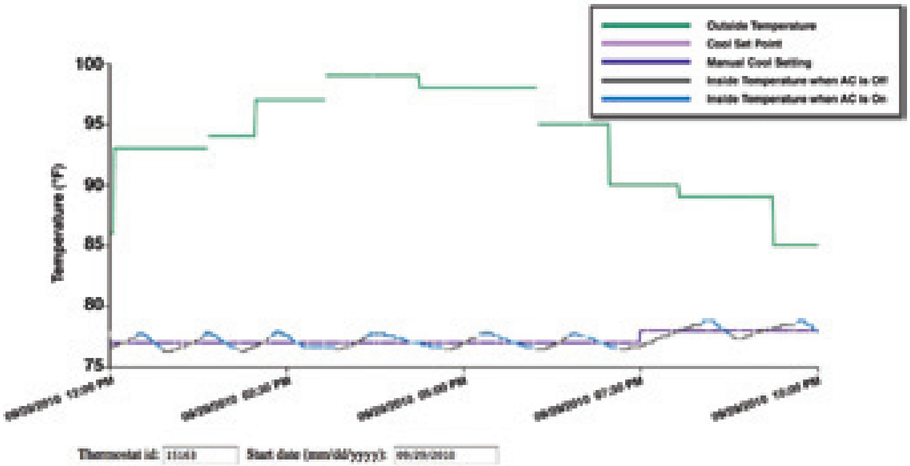


Figure 1A: Temperatures and A/C cycle times, no DR

As **Figure 1B** shows, with one hour of pre-cooling, inside temperature at the start of the DR event was almost two degrees below the set point, and it took roughly two hours for the temperature inside the home to reach equilibrium at the four-degree higher DR set point.

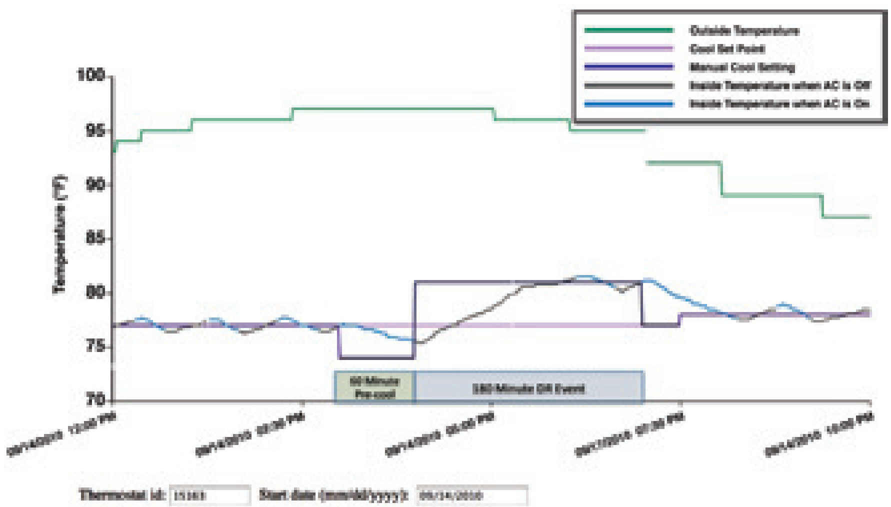


Figure 1B: Temperatures and A/C cycle time, 60 minutes of pre-cool, 180-minute event

As shown in **Figure 1C**, with 90 minutes of pre-cooling, inside temperature at the start of the DR event was almost two and a half degrees below the set point, and it took roughly two and a half hours for the temperature inside the home to reach equilibrium at the four-degree higher DR set point.

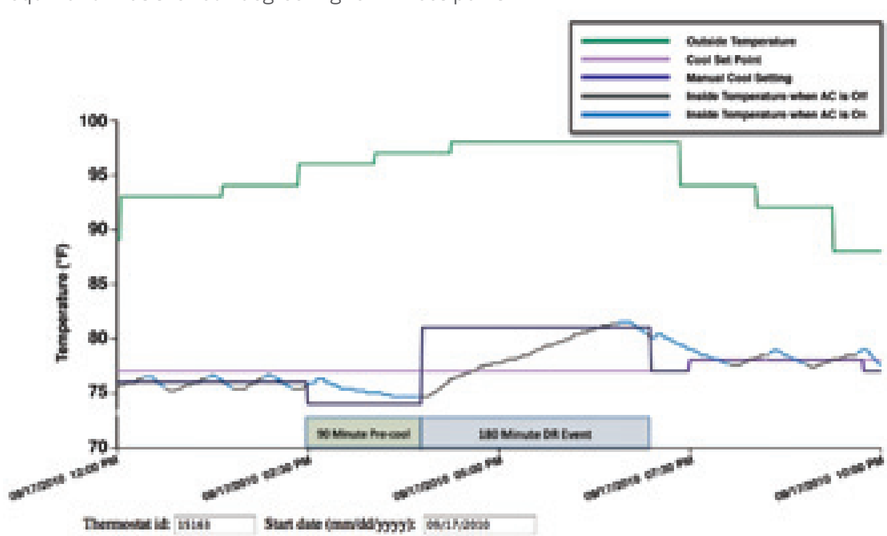


Figure 1C: Temperatures and A/C cycle time, 90 minutes of pre-cool, 180-minute event

As shown in **Figure 1D**, with 120 minutes of pre-cooling, inside temperature at the start of the DR event was more than three degrees below the set point, and the temperature inside the home did not reach the four-degree higher DR set point during the 3 ½ hour event.

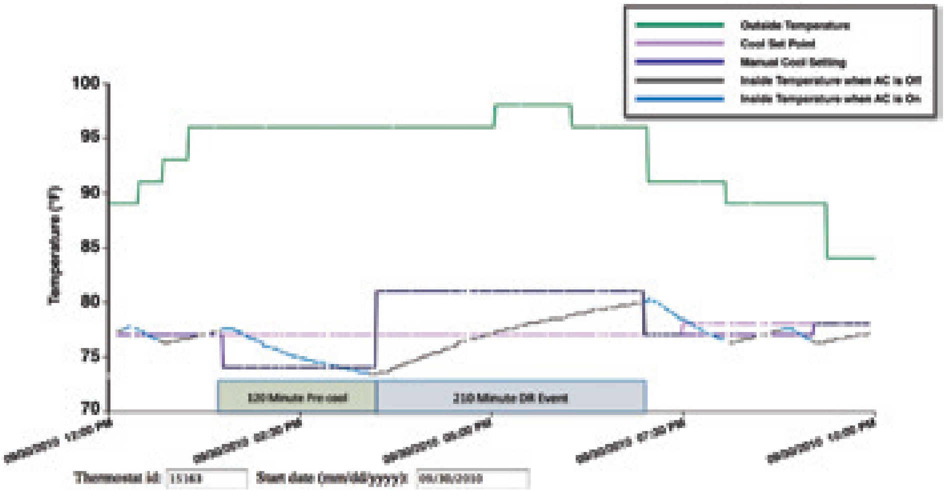


Figure 1D: Temperatures and A/C cycle time, 120 minutes of pre-cool, 210-minute event

A summary of the data included in the above figures follows:

Minutes A/C Idle (Off)	Total Event Minutes	Minutes of Pre-Cooling	% Idle Time during Event Window (4-7pm)	Premise
57	0	0	31%	15163
149	180	60	82%	15163
153	180	90	85%	15163
210	210	120	100%	15163

Again, this single premise data is for illustrative purposes only at this point; more comprehensive analysis is currently underway.

An example of how yield can be increased even when consumers opt out is shown in **Figures 2A** and **2B**. **Figure 2A** illustrates a common occurrence with four-degree setback strategies: the occupant tolerated the load shed until the temperature inside the home reached their comfort limit (about 80 degrees in this case). This triggered a manual override 43 minutes into the event.

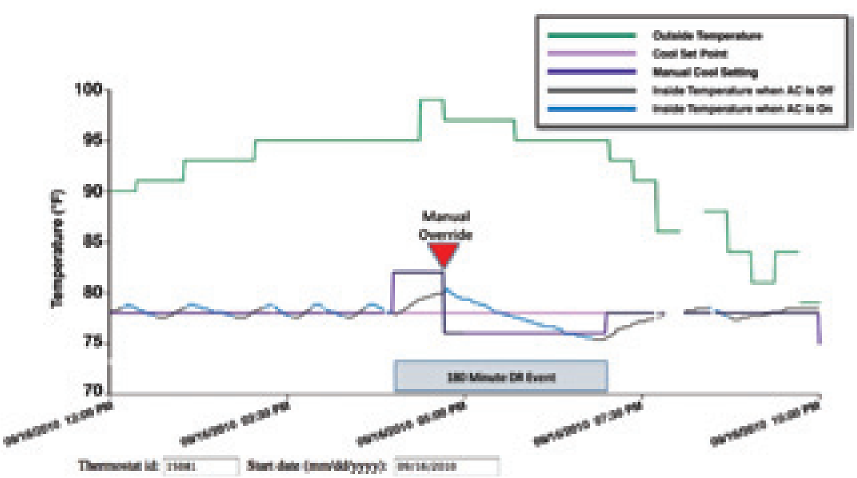


Figure 2A: Temperatures and A/C cycle times, Standard four-degree setback, 180-minute event

Figure 2B shows that pre-cooling can deliver value even when occupants are unwilling to tolerate discomfort. In the same home as shown in **Figure 2A**, only one day later, significantly better results were obtained with pre-cooling. A 90-minute pre-cooling period meant that the inside temperature when the DR event began was two degrees lower than was the case without pre-cooling. The occupants still ended their participation with an override, but this time the override did not occur until 78 minutes into the event. Thus the load shed contribution nearly doubled.

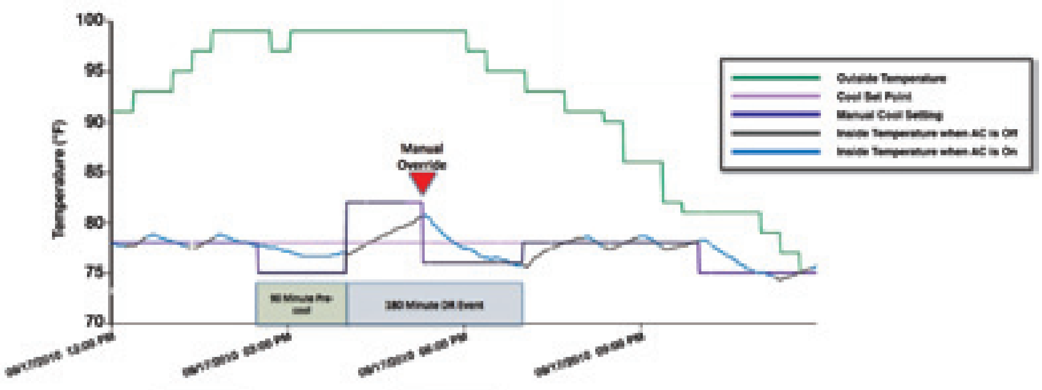


Figure 2B: Temperatures and A/C Cycling, 180-minute DR, 90-minute pre-cool

Conclusions & Outlook

Pre-cooling has the potential to increase DR load impacts by increasing the number of minutes that air conditioners are off during event windows, both with and without customer intervention via override. The system could perform that at scale while providing robust data for analytics. However, does that mean mass customization of *optimized* pre-cooling strategies adds value?

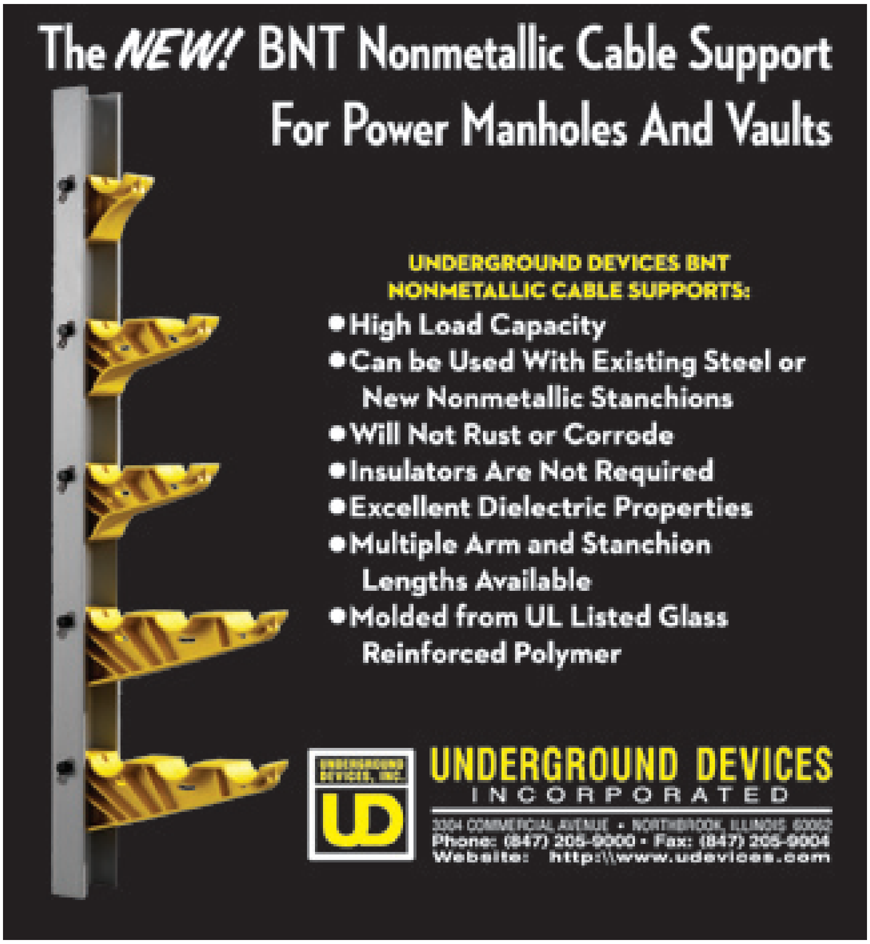
Could optimized pre-cooling be used to help accommodate Richard's demands? Could a strategy limited by the customer to plus or minus two degrees of their preferred set point achieve the same load impact results as a standard four-degree setback? If so, would it reduce the number of customers that perceives a comfort impact due to the event?

The 2010 pilot was intended to give NV Energy a preliminary indication of the merits of various pre-cooling strategies based upon premise-specific conditions and the preferences of individual customers. That goal was achieved, and although the limited size of the first-year pilot precludes definitive answers to some additional very interesting questions, the initial results look promising. ■

ABOUT THE AUTHORS

Michael Brown has over fourteen years of experience in the energy sector focused on demand response, energy efficiency, and renewable energy in both deregulated and regulated electricity markets and has held a variety of positions at consulting and energy service firms. Since joining NV Energy in 2005, his roles have included the design and implementation of demand-side management programs. His efforts in the Demand Response and Smart Grid domain have included the design and implementation of *Cool Share* – the largest two-way communicating programmable thermostat program in the country. Michael has a Bachelor of Science in Chemistry and International Relations from The College of William and Mary, and a Master of Business Administration from the The Cranfield School of Management.

John Steinberg has become a forceful advocate for putting consumer value at the center of the smart grid. He co-founded EcoFactor in 2006 in order to bring to market a solution focused on delivering a demand-side solution that consumers will actually want to use. John has been issued 17 US patents covering innovations in energy management as well as such diverse fields as digital photography, networked printing, and various mechanical devices.



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2011 GreenWays Series

Leadership for a Clean Energy Future

AEP Texas

A Unit of American Electric Power

By A. Wade Smith, President & Chief Operating Officer and
Joel S. Murphy, Director - Customer Services & Marketing

AEP Texas comprises two primary operating companies. AEP Texas North Company delivers electricity on behalf of Retail Electric Providers (REPs) in west Texas, and AEP Texas Central Company delivers electricity on behalf of REPs in south Texas. Under deregulated Texas market guidelines, AEP Texas builds new power lines, reads meters for the REPs, restores service following outages and connects or disconnects service as requested by REPs. Although AEP Texas is but one of 7 operating companies under its corporate parent – American Electric Power – our interview is focused primarily on the strides being made under the *gridSMART* initiative currently being rolled out by AEP Texas. – ***Ed***.

EET&D: Let's begin with a little bit of background on American Electric Power – your parent company – and then we'll move on to AEP Texas itself.

Smith: AEP Texas is part of the American Electric Power system, one of the largest electric utilities in the United States, delivering electricity to more than 5 million consumers in 11 states. AEP ranks among the nation's largest generators of electricity, owning nearly 38,000 megawatts of generating capacity in the U.S. AEP also owns the nation's largest electricity transmission system, a nearly 39,000-mile network that includes more 765 kilovolt extra-high voltage transmission lines than all other U.S. transmission systems combined.

EET&D: Maybe you could tell us a little more about the AEP power delivery network, which is quite extensive, and I would say, quite impressive by its sheer size.

Smith: The AEP transmission system directly or indirectly serves about 10 percent of the electricity demand in the Eastern Interconnection, the interconnected transmission system that covers 38 eastern and central U.S. states and eastern Canada, and approximately 11 percent of the electricity demand in ERCOT, the transmission system that covers much of Texas. With its corporate headquarters in Columbus, Ohio – from which Joel and I both arrived a little over a year ago – AEP's utility units operate as AEP Ohio, Appalachian Power (in Virginia and West Virginia), AEP Appalachian Power (in Tennessee), Indiana Michigan Power, Kentucky Power, Public Service Company of Oklahoma, Southwestern Electric Power Company (in Arkansas, Louisiana and east Texas) and, of course, AEP Texas.

EET&D: Joel, while many of our readers probably have at least a cursory familiarity with the large and diverse geographical presence of American Electric Power, the AEP Texas operation seems unique in some ways.

Murphy: It definitely is. AEP Texas is headquartered in Corpus Christi, with Regulatory and Governmental Affairs offices in Austin. Major cities served include Corpus Christi, Abilene, McAllen, Harlingen, San Angelo, Vernon, Victoria and Laredo. AEP Texas is connected to, and serves, more than one million electric consumers in a deregulated marketplace. That is the main thing that makes us unique since it is certainly a very different operating environment from most other parts of the country.

EET&D: In the Texas deregulated market, unlike a lot of vertically integrated investor-owned utilities with bundled generation, transmission and distribution, AEP Texas is purely an energy delivery – or 'wires' – company. What does that translate into in terms of the services you provide to consumers?

Smith: AEP Texas delivers electricity to homes, businesses and industry across its nearly 100,000 square mile service territory in south and west Texas. We build, maintain and repair lines, read electric meters and handle connections and disconnections as directed by the REPs selling electricity within our service area. We have no retail customers in the traditional sense of the word. That provides a different set of challenges as compared to the historic vertically integrated utility.

EET&D: I'd like to turn now to your Smart Grid program, which you call your *gridSMART* initiative. Wade, perhaps you'd like to lead off with a quick introduction to lay out the general framework for AEP's *gridSMART* initiative in Texas...

Smith: I'd be happy to. Let me first explain the foundations of our approach, which are perhaps a little different from some of the other Smart Grid projects around the country. As you know, we don't mind doing things a bit differently in Texas!

EET&D: Yes, I've seen that myself over the years, so I'm not too surprised that Texas would have its own way of seizing and acting on this opportunity.

Smith: The main focus of our initiative is engaging in the development, integration and deployment of what we are calling our Advanced Metering Infrastructure (AMI) System throughout the AEP Texas service territory. AEP Texas has worked – and will continue to work – cooperatively through multiple alliances to develop and deploy equipment and technology programs for the enhancement of AEP's electricity value chain, from the power generation station to the end use customer.

EET&D: How and when was your Smart Metering project started?

Murphy: When the Texas legislature first passed "Smart Meter" legislation in 2005, we were actually in the midst of a one-way AMR deployment, but the new legislation caused our deployment to be suspended. The Public Utility Commission of Texas (PUCT) adopted the Advanced Metering rule in May 2007. And in December of 2009, the PUCT approved cost recovery of our AMI deployment in Texas through an 11-year surcharge.

Smith: From a historical perspective, I think it's useful to note that the Texas electric retail market was deregulated in 2002, thereby enabling customer choice and competitive pricing of electric supply. This created a new entity, Retail Electric Providers – or REPs as they are called – which completely changed the relationship between the customers and their traditional electricity providers.

EET&D: How do the REPs figure into your current AMI plans?

Murphy: AEP Texas – with the help of a cross-functional team of AEP personnel – selected a 900 MHz radio frequency mesh system as our AMI solution. The new AMI System will allow the Retail Electric Providers to provide real-time pricing information and new products to customers as they evolve and come on line. It also will enable our current distribution resources to respond more quickly and efficiently to local conditions.

EET&D: What do you expect some of the more important benefits from your AMI initiative to be?

Smith: Among other things, AEP Texas anticipates that enhanced consumer service and the ability to remotely execute certain meter related activities will significantly reduce fees associated with these services. But why did we choose to focus on AMI to begin with? The reasons are several. It started in 2005 when the Texas legislature passed legislation creating the technology standards for Advanced Metering.

EET&D: Armed with that legislative mandate, what action did the PUCT take?

Smith: The PUCT, in 2007, adopted a rule allowing utilities to recover their costs through a non-bypassable surcharge. This move encouraged us and other transmission and distribution utilities to deploy our AMI Systems.

EET&D: I understand that there are also some mandatory functions in the Texas plan. What are some of those?

Smith: The mandatory requirements are actually quite detailed and very rigorous. For example, remote meter reading, two-way communications, remote connection and disconnection, time-stamping of 15-minute interval meter data, and data storage using open standards and protocols are all mandatory. In addition, the AMI System must be able to communicate with on-premise devices and provide direct, real-time access for customer and retailer-to-meter data, and be upgradable.

EET&D: What are the main elements of the *gridSMART* initiative that are encompassed and embodied by the AEP Texas project scope?

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Murphy: Naturally, the foundation of our *gridSMART* effort is a robust AMI communications network. There are approximately 1 million smart meters in the program, all with remote connect and disconnect and support for various other features, including Home Area Networks (HANs) and the Smart Meter Texas Portal – an opt-in, online database portal that provides customers with access to detailed usage data.

EET&D: Maybe you could give our readers a quick overview of your network infrastructure, since you said that is the underlying foundation of *gridSMART*?

Murphy: Our chosen AMI communications infrastructure is a 900 MHz RF mesh network, which is provided by Landis+Gyr. Within this network, meters communicate with their neighbors giving us numerous paths for acquiring meter data and thereby vastly increasing throughput across the network. Each router on the system supports up to 14,000 meters and passes the data on to collectors that gather it from the network and send it upstream to the head-end system.

EET&D: What is the status of your AMI deployment at this point?

Murphy: We initiated a 48-month deployment plan in 2010, and at the present time we are on track for a 2013 completion with over a third of our total meter population now deployed across both our Texas North and Texas Central operating regions.

EET&D: In closing, please elaborate on how you see the future unfolding once your initial *gridSMART* deployment is completed?

Smith: When we look into the future, we view it from three distinct, but closely interrelated perspectives: the consumer, the utility and the regulator. From the consumer perspective, the AMI System will have the capability to support dynamic pricing (i.e., Time of Use, Real Time Pricing, etc.); a possible prepaid service model, where it makes sense; an ability to support consumer in-home networks including Web access to meter/usage data and enabling technology for load control/demand side management.

Murphy: Also from a consumer service standpoint, more granular load data allows us to support better market research; faster and more efficient service connect/disconnect and special reads; enhanced reliability through outage detection; quicker restoration after an outage; and fewer estimated bills, as well as improved peak load control.

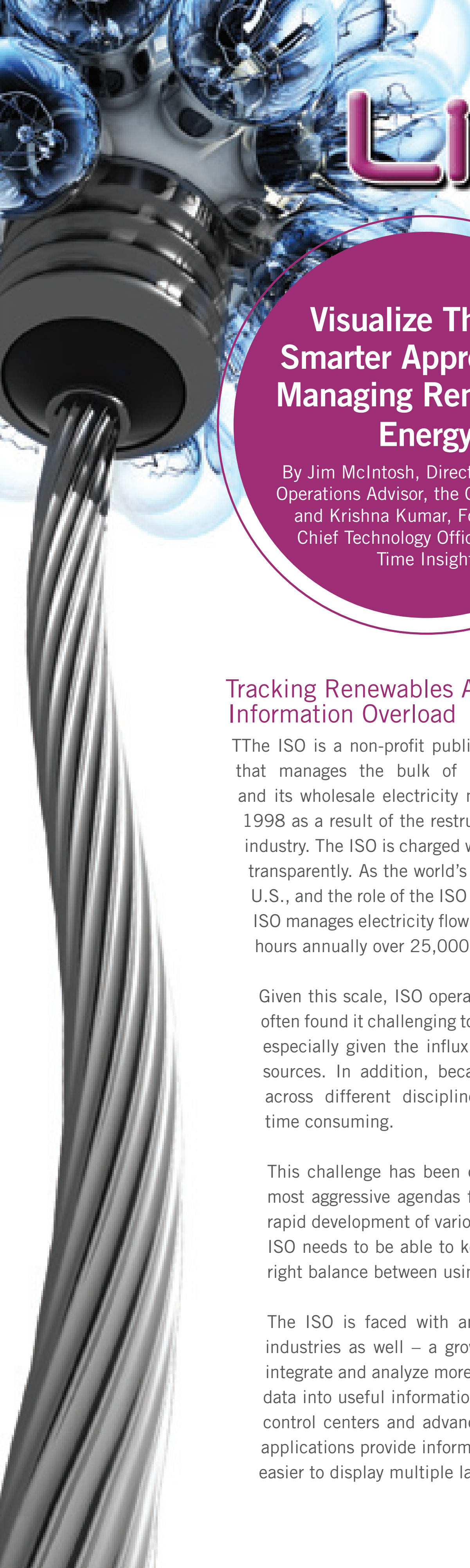
EET&D: So what's in this for the utility, besides the obvious benefits that can be derived from improved service for consumers?

Murphy: Better energy grid management is a big one. We are looking forward to having voltage and load data on all meters to support our future system planning efforts, to make them more effective, accurate and efficient. Of course, preventive maintenance initiatives, and pro-active outage notification capabilities, which lead to better and earlier estimations on outage scope and restoration will significantly reduce field visits for both outage and non-outage ticket call-outs.

Smith: On a broader level, safety. Keeping our employees safe is very important to us; we will benefit from reduced exposure to hazards that cause accidents and injuries.

EET&D: And finally, how and where does the regulator fit into this picture?

Smith: The regulators have been our partners throughout this venture. We are mindful that we are putting in place enabling technologies that will benefit consumers. These include energy efficiency, demand-side management and various other cost management measures. New processes will improve communication with consumers, improve reliability and security and deliver a higher level of consumer satisfaction. In short, *gridSMART* is a game-changer. The status quo has a finite shelf life. Those who stay ahead of the wave will define the future. ■



LightsOn

Visualize This: A Smarter Approach to Managing Renewable Energy

By Jim McIntosh, Director-Executive Operations Advisor, the California ISO and Krishna Kumar, Founder and Chief Technology Officer, Space-Time Insight

The California Independent System Operator's (ISO) new control center houses the first dedicated renewables dispatch facility in the nation, and what makes this facility unique is a new grid visualization technology powered by advanced geospatial software. This technology enables dispatchers to adjust in real-time to current weather conditions, while enhancing wind and solar performance forecasting. Overall, it helps the ISO maintain a reliable flow of renewable power, an economic imperative in California, and sets the stage for the state to achieve its goal of generating 33 percent of its power from renewable resources by 2020.

Tracking Renewables Adds to Information Overload

TThe ISO is a non-profit public benefit corporation that manages the bulk of California's power grid and its wholesale electricity market. The ISO opened in 1998 as a result of the restructuring of the state's electricity industry. The ISO is charged with operating the power grid openly and transparently. As the world's eighth largest economy, California is an economic engine for the entire U.S., and the role of the ISO is to ensure the state always has the power it needs to keep running. The ISO manages electricity flow for 80 percent of California's power grid, delivering 286 billion kilowatt-hours annually over 25,000 miles of power lines for about 35 million Californians.

Given this scale, ISO operators who were previously analyzing data in a traditional tabular format, often found it challenging to spot trends and anomalies, and respond quickly to changing conditions, especially given the influx of data points necessary to track an increasing number of renewable sources. In addition, because the ISO relied on independent software systems and processes across different disciplines, sharing and synchronizing information was often complex and time consuming.

This challenge has been compounded over the years because California has one of the world's most aggressive agendas for addressing climate change, and as part of that, the state is seeing rapid development of various wind and solar facilities, along with other intermittent resources. The ISO needs to be able to keep very close track of these variable resources in order to achieve the right balance between using renewables and ensuring reliable power.

The ISO is faced with an increasingly common issue in the power industry and many other industries as well – a growing mountain of information to assimilate. How can an organization integrate and analyze more and more complex data in an efficient manner? How can it turn all that data into useful information? The California ISO sought a technology solution as it modernized its control centers and advanced visualization displays turned out to be the answer. New computer applications provide information in pictures rather than thousands of information points, making it easier to display multiple layers of data in a faster-to-consume manner.

Finding a Solution

In 2008, ISO operators faced a daunting challenge; large wildfires were burning close to transmission power lines. A rapid search for a solution uncovered Space-Time Insight, a company pioneering a visual analytics technology called situational intelligence.

Given the time-sensitive nature of the problem, an important advantage of the situational intelligence solution was that it could plug easily into the ISO systems and processes. The software integrates with data from different systems, correlates it with external data feeds and presents the results in intuitive visual displays used by the ISO's operators and managers. It was important that the software could support the large volumes of data generated by the ISO's infrastructure, and enable event-based correlations between points of information across space, time and node to identify problem areas, determine root causes of those problems, and facilitate rapid action on the part of operators. Most important, the solution enables the ISO's operators to quickly visualize and analyze the data, accelerating the recognition of trends and anomalies and reducing response times.

The ISO deployed and customized the Space-Time Insight Crisis Intelligence application, combining information from CAL FIRE showing areas that have already burned, input from an infrared system highlighting areas still burning, as well as wind speed and trajectory data. This information is then overlaid on a map of the transmission system, providing operators with a clear visual representation of any lines at risk.

Because the Crisis Intelligence application enables operators to see and respond to fires in real-time, they can stay ahead of dynamically evolving situations – sometimes hours in advance of what was previously possible – and proactively work with local utilities to develop action and contingency plans. For example, they can move power flow off any lines that might be affected by a fire, protecting customers from a potential power loss and eliminating the possibility of damage caused by a fire hitting live power lines.

Based on the success of the Crisis Intelligence application, when the ISO launched its Market Redesign and Technology Upgrade (MRTU) initiative in 2009, it extended the use of situational intelligence into the wholesale electricity market.

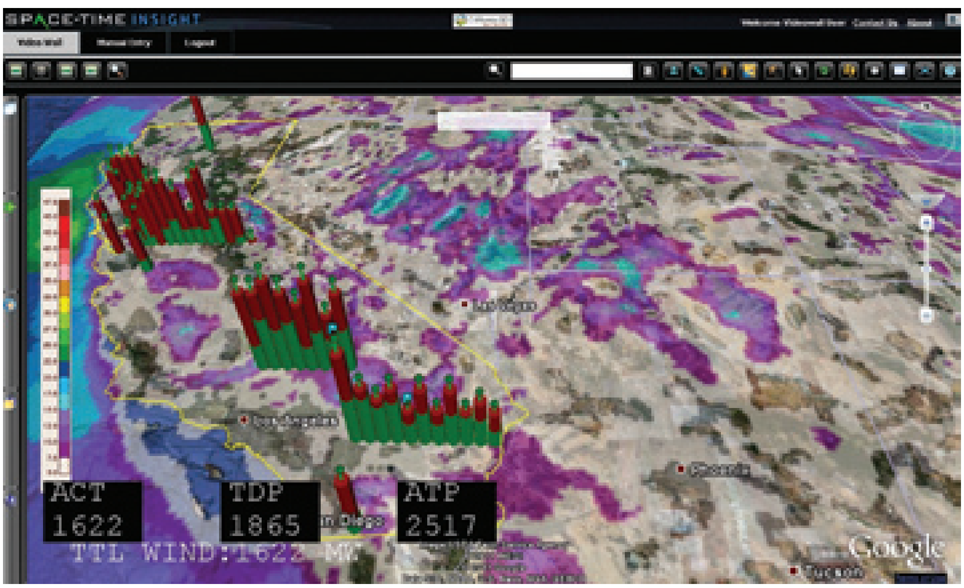
The goal was to improve the efficiency of the market and track prices at 4,500 locations in California. The application enables the ISO to visualize real-time and day-ahead prices every five and 15 minutes through a price contour map that indicates where prices are high and where they are low. Patterns can be tracked and captured to send signals for where investments in new resources could best benefit growing power needs in a particular geographical area.

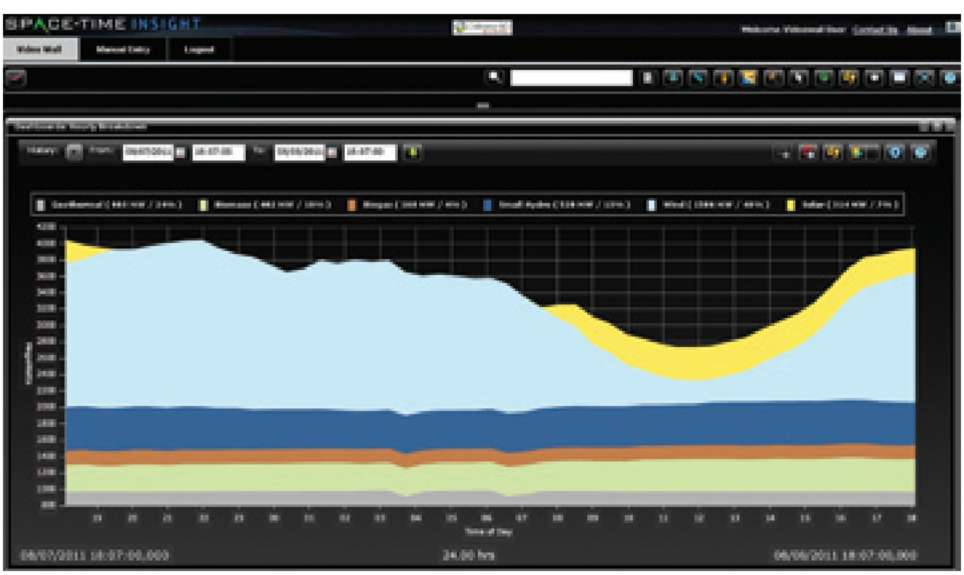
Tracking Renewables the Intelligent, Visual Way

Recognizing that meeting California's aggressive renewables goals require more precise management of renewable resources, the ISO needed a technology solution that would help accomplish that. So, based on the success of the two prior applications, the ISO implemented Space-Time Insight's Renewables Intelligence solution. It provides dispatchers with the ability to assess, in real-time, current conditions – such as how unexpected storms, cloud cover and wind speed might impact solar fields and wind farms – so they can make appropriate adjustments to optimize the use of renewable power.

In addition, the application enables the ISO to stay within defined limits on the circuit path, which prevents damage to the power system infrastructure and helps avoid millions of dollars in potential fines. It also helps keep California on its emission-reduction trajectory. The application tracks all the different generation sources – conventional hydroelectric, solar and wind –displaying their varying real-time outputs and external impacts, such as clouds passing over a region and winds kicking up as inland regions heat up in the afternoon. For example, one display (below) combines weather feeds and cloud cover data with infrared solar imagery to show the impact of clouds and weather patterns on solar generators.

Another display shows wind speed contours, allowing operators to see pockets of fast-moving air approaching the wind generation fleets. This is very helpful in California where forecasting can be difficult because of the different geographies and climates. In the hot Tehachapi Mountains in Southern California, for instance, there are four micro-climates within one little pocket, making forecasting very complicated. The Solano and Altamont regions in the Bay Area are a little more predictable, but the cooler temperatures also mean an influx of a variety of airflows that need to be tracked.





Bringing It All Together

Recently, the ISO incorporated the applications into a new 80 ft. x 6.5 ft. video wall that fronts a state-of-the-art control center. The video displays focus on the speed at which power plants can be brought online, voltage stability, renewables forecasting, congestion management and grid reliability. Plus, the displays contain multiple layers of information at a glance and quickly alert operators and managers to potential problems. While individual users have access to relevant screens at their desktops, the 10 visualization screens on the video wall create a tremendous leap forward in enabling a big-picture view of the entire system, ensuring optimal information sharing, as well as trend and anomaly detection.

For example, a renewables portfolio displayed on the video wall shows a rolling 24-hour view of the energy produced by the basic renewables groups. Color-coding shows the usage of different energy sources. A dip in solar output is clearly visible during the night period, and the wind output reflects the variances in wind speed. One part of the display shows what small hydro facilities (capable of 30 megawatts production or less) are producing. Biomass, biogas and geothermal sources are also illustrated, each of which contribute to the renewables equation. By studying the 24-hour look-back and comparing the weather pattern for that period with the forecast for the next 24 hours, ISO generation dispatchers can make more accurate predictions about changing patterns and adjust their set points out to the generators.

The success of the new visualization capabilities is measured in how effective the ISO operators are, how reliable the system is and how effectively renewables are being integrated into the system. Today, the ISO operators are more productive and effective despite a far more complex environment. And the ability of the ISO to avoid blackouts and disruptions in supply means that the applications are enabling the ISO to successfully increase the renewables level on the grid while maintaining reliability, which is the ultimate goal.

Conclusion

With its aggressive renewable standards, California is really a rehearsal for renewables management across America. And because of this, the ISO has to deploy innovative solutions that allow it to respond in real-time to factors such as wind changes and cloud pattern developments that directly impact renewable energy generation. Only by presenting operators with information in a way that they can quickly digest it and respond to, can the ISO maintain reliability at the lowest possible cost.

The beauty of the ISO's new geospatial renewables system is that it makes complex data easy to understand. It's right there on a visual display for operators to see. And the system not only lets the ISO build all the various data sources into macro-view indicators, but also enables operators to dig into the details and perform analytics on the data itself. By combining external data sources with internal data, by polling the grid in millisecond intervals, and by presenting the results in a very intuitive visual display, the ISO gets a far clearer and more actionable picture of what is going on.

The transition from traditional line diagrams to the rich geospatial displays is similar to the difference between x-rays and MRIs. Now, the ISO is getting far more information, and getting it in a way that makes that information more usable. It's one of the few applications in the ISO control center capable of doing that, helping overcome the "information-overload" syndrome from which so many other organizations are suffering. It's completely changing in scale and timeframe what the ISO can achieve and is helping the organization deliver on its mission to help green California. ■

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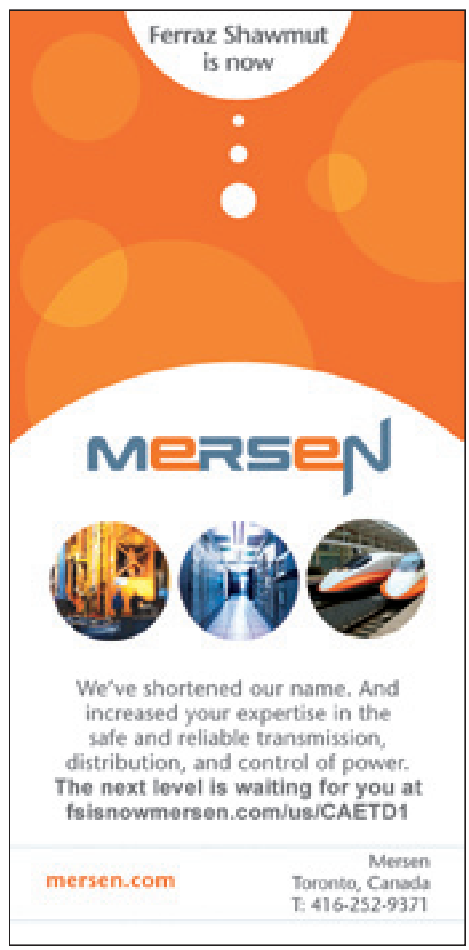
As Founder and CTO of Space-Time Insight, **Krishna Kumar** leads vision and strategy for the Space-Time Insight suite of products. He pioneered the innovation behind Space-Time Insight's Space-Time Awareness Server (STAS) that analyzes, correlates, and geospatially visualizes data from multiple data sources and enables initiation of preventive action from a geospatial screen. He is regarded by leading energy companies as a thought leader in real-time, situational intelligence and high-context visualization of geospatial analytics. Recognized for his vision and innovative spirit, Krishna is a popular speaker at tradeshows and conferences worldwide.



Circle 6 on Reader Service Card

The IT Project Hidden Within Your MDMS Initiative

By Mark Hatfield, Principal Consultant, and Scott Stein, Principal Consultant
Enspiria Solutions, Inc. — a Black & Veatch Company

The Advanced Metering Infrastructure (AMI) portion of a Smart Meter or Smart Grid project typically gets the lion's share of attention, often because it can represent more than 75 percent of the cost. Additionally, AMI monopolizes the contracting and planning process, physically touches each customer premise, and generates widespread public interest. Given the visibility of the AMI, it is not surprising that Smart Meter and Smart Grid projects rarely emphasize the equally important data management systems required for successful implementation.

The Meter Data Management System (MDMS) component of a Smart Meter or Smart Grid project is often treated as an afterthought with little or no consideration given to the data management solution during the initial AMI project stages. With the focus on Smart Meter deployment, it is easy to overlook the fact that, as your project progresses, the MDMS will grow from a minor data system to a mission critical enterprise-class IT system responsible for achieving most of your enterprise business benefits. It is imperative to understand the importance of the MDMS in a project's infant stages to position it appropriately as a complex IT system, critical to the success of the AMI project.

To position the MDMS as an enabler for the future, it is important to recognize that you are embarking on a critical, complex IT project within your Smart Grid initiative. Primary IT considerations should be examined and planned during the forefront of the project to achieve the highest possible level of success and value. This article discusses four strategic positions that must be considered during MDMS IT Project planning.

1. The MDMS should be managed within the IT domain and as an IT project.
2. Architectural definition, positioning and vision are critical to leveraging the MDMS value properly within the enterprise.
3. Failure to estimate the level of IT complexity within the MDMS implementation can compromise project results.
4. Establishing future phases and enhanced roles of the MDMS beyond basic meter-to-cash at inception will ensure architectural continuity for the future.

The MDMS should be managed within the IT domain and as an IT project.

Two fundamental risks during MDMS project initiation are improper project alignment and lack of stakeholder sponsorship. Consider the flow of most AMI deployments: first, the utility realizes the need to become Smart Grid enabled; second, project owners launch a strategy, which includes business case and funding development; and third, stakeholder analysis begins in preparation for vendor selection of an AMI solution. Meanwhile, the IT support elements, including the MDMS, represent a subset of activities within the overall AMI program.

Now consider these factors: in most cases, the AMI project is positioned as a subcomponent of the broader Smart Grid vision. This is usually based on the assumption the AMI project will be comprised of an AMI field network, smart meters and AMI communications circuits for backhaul, and all of these components will reside on the distribution system. For these reasons, the AMI project is often assigned as either an extension of Meter Operations or as its own, independent initiative with a separate project team. The MDMS becomes a sub-component within the AMI project. This seemingly natural assignment of the MDMS is misplaced. Consider this question: "Is the MDMS an extension of the AMI Data Collection System or should it serve as a gateway into the holistic IT Enterprise?"

Examining the logical implementation of the MDMS will lead to the proper MDMS positioning as an IT solution. The MDMS lives within the IT infrastructure as a software solution. It provides a crucial "normalization interface" of varied network and meter data collection. It also provides communications for ALL types of field data (MV-90, multiple AMI systems, Manual Read systems) to the remaining processing components of the utility's IT solutions (Customer Information System [CIS], Customer Portal, Outage Management System [OMS], Work Management System [WMS], Demand Response Management System [DRMS], etc).

The stakeholder analysis and design/integration decisions depend upon examination of the IT architectural Smart Grid vision. Consider the MDMS as a primary AMI component early in the project initiation stages and position it with true considerations of the IT complexity.

While positioned as an IT system, a utility's business units maintain a critical role in implementing the MDMS, running the MDMS on a daily basis, and integrating the MDMS functionality into business processes. IT departments cannot implement a MDMS in isolation. In turn, business units cannot achieve the full potential of a MDMS without IT contributing.

Architectural definition, positioning, and vision are critical to leveraging the MDMS value properly within the enterprise.

The big question that does not necessarily produce an obvious answer is: "What do I want my MDMS to do given my current architecture and vision for the future?"

In our experience, no two utilities are alike with regard to IT enterprise systems, macro and micro business case objectives, operating environment, or IT vision. Determining your IT architectural vision and strategy prior to MDMS implementation is a critical, value-added step that should precede vendor selection. The basic goal is to comprehensively evaluate and understand the core components the MDMS should fulfill in addition to the detailed functions the MDMS solution should achieve. Not all MDMS solutions are created equal. Understanding the right fit in form and function will help you make the right selections.

The following provides example questions that will help you resolve your MDMS solution requirements. These questions should be answered and evaluated prior to vendor selection.

- What infrastructure is required to meet the business case objectives?
- What solutions are currently in place that can be leveraged to achieve these benefits?
- What solutions should be acquired or further leveraged to achieve these benefits?
- Are all of the solutions scalable for AMI?

During the solution implementation, after vendor selection has occurred, project owners should examine issues to resolve and refine IT integration requirements. Key questions include:

- What is the System-of-Record (SOR) for various data elements?
- What is the integration methodology and AMI compliance standard?
- What is the data warehousing strategy and utilization model?

The actual answers to these questions are of secondary importance. The greatest benefit lies in asking these questions to prompt careful evaluation of critical implementation directives. Implementation needs to be phased, designed, developed, tested and transitioned into the operational workflow with the highest level of data integrity.

Failure to estimate the level of IT complexity within the MDMS implementation can compromise project results.

Typical Smart Grid programs include the installation of an AMI network communications and metering solution, requiring a complete meter replacement. The primary capital component of your project will, of course, reside in the meter purchase and replacement project. Ironically, despite its funding requirements, the AMI meter exchange represents one of the lowest risk initiatives within the overall project.

In contrast, the MDMS is an extremely complex system from the perspective of the number of systems it can touch; the number of business processes impacted; and the large amount of data that must be managed. The MDMS represents a substantial portion of the project's risk, yet typically comprises less than 15 percent of the overall capital budget.

MDMS Touch Points

The MDMS will perform its primary functions in the meter-to-cash business process, initially touching the CIS, AMI head-end system, and potentially other legacy meter data collection systems such as MVRS and MV-90. Other common value propositions in the early project phases include integration with OMS, Interactive Voice Response (IVR) and Revenue Protection systems. Deeper integration can be performed in the future phases to provide data feeds and interact with DRMS, consumer portals, load research, distribution planning, Geospatial Information Systems (GIS), and external services such as pre-pay solutions. (**See Figure 1**)

This level of integration, along with the potential to align with an enterprise service bus and support the future development of data extraction processes, is consistent with an enterprise IT system. Designing and planning an integration with this level of complexity requires attention to detail of several integration factors, including:

- Appropriate integration method
- Transaction payload
- Process and system scalability
- Process and system security
- Process timing
- Data retention
- Standards adherence
- Customization impacts and many others.

An implementation of this complexity will require a diverse set of skills that best reside within the IT organization.

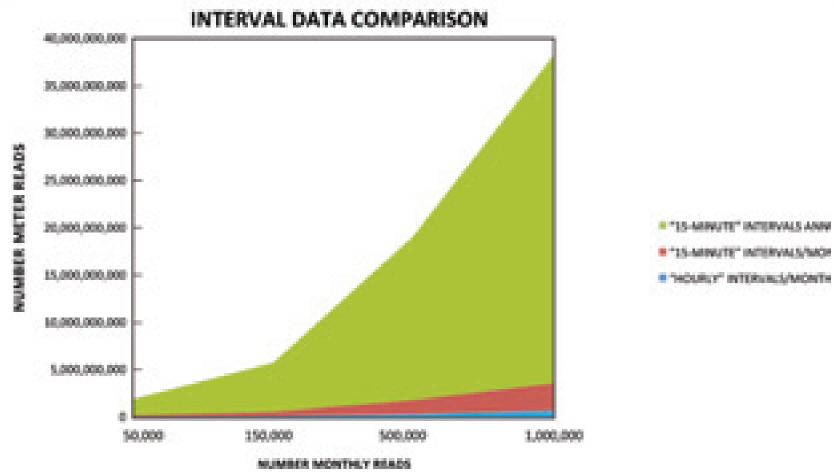


Figure 2 – AMI Reads at Selected Intervals

Business Process Impacts

Business process modeling is an important aspect of an AMI implementation. Although numbers vary depending on the MDMS vendor, the meter-to-cash portion of most AMI implementations requires approximately 15 business processes. Of these processes, approximately eight directly involve the MDMS, for example, meter commissioning, daily data exception handling, billing, to name a few. As you move beyond meter-to-cash and include more of the processes and systems depicted in **Figure 1**, the role of the MDMS will increase. A conservative estimate adds 20 business processes beyond meter-to-cash, almost all of which will employ the MDMS (depending on the MDMS selected). Again, the reach of the MDMS across the organization is reflective of an enterprise IT system.

Large Volume of Data

It is stunning how fast the data model will grow in volume with the implementation of the AMI solution. This can be a shock to most utilities.

Figure 2 provides an illustration of the amount of data collected using an AMI baseline sample of 150,000 service points running on 15-minute intervals. As represented in the illustration, this results in 450 million intervals per month for single-channel usage data collection only. This does not account for multiple channel data, meter events, or additional AMI module events. This massive amount of data volume demonstrates why the skills within the IT organization are required for the care and maintenance of these systems. Advanced DBA skills for database monitoring, tuning and archiving are critical for efficient operations. These are skills that lie within the IT organization.

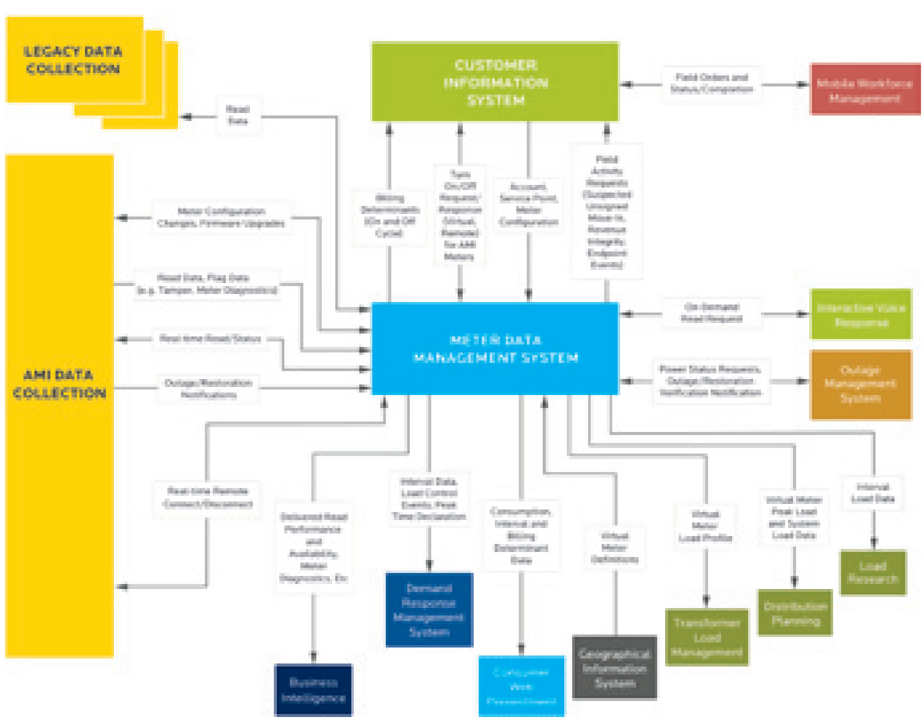


Figure 1 – Representative AMI System Diagram

The MDMS is the solution that will validate, estimate and edit the interval data. The MDMS will also process all received data for billing determinants delivery to the CIS, as well as post data for customer consumption. These are just a few of the critical processes that present the highest risk to the overall Smart Grid implementation.

Establishing the future phases and enhanced roles of the MDMS (beyond basic meter-to-cash) at inception will help to ensure architectural continuity for the future.

Transforming to a Smart Grid utility is a journey. While an AMI solution has the ability to provide a large volume of metering and network data, an MDMS that is properly positioned within the IT enterprise can establish the means for continual Smart Grid evolution.

On the other hand, if the AMI and supporting MDMS solution is implemented without the proper sponsorship and vision, it can end up as little more than an expensive meter reading system. This all depends upon the IT implementation and vision to leverage the massive data potential utilization to achieve valued benefits.

The market is a fantastic labyrinth of entrepreneurial solutions. Demand response management, home area networking, electric vehicles, consumer web portals, distributed generation, and other initiatives are in their infancy. Building a basic distribution load data collection and data processing infrastructure is the foundation gaining comprehensive insights on the affects these technologies have on their grid. The MDMS can and does play the leading role in AMI data processing; therefore, it is the critical IT solution that must be leveraged properly to feed ancillary systems. The level of IT integration drives the value of AMI and MDMS implementation.

Summary

When determining the MDMS project placement within the overall Smart Grid initiative, it is critical to regard the MDMS as a software solution that should be defined, implemented and managed as part of the IT enterprise.

The MDMS is a complex IT implementation not to be taken lightly. Work with your executive sponsorship team to align the project based on risk factors, and avoid the natural trap of allowing the MDMS to fall below the radar because of its lower price tag. Take into account the sheer data volume increase and associated data processing when defining the architecture. Define both your architecture's current ability to support AMI, and the future state that includes the MDMS solution opportunity within the enterprise. Consider future initiatives and possible extents of market evolution within your enterprise vision, and determine the potential role of the MDMS. Apply your best IT implementation lifecycle practices to the MDMS solution as a mission critical system.

ABOUT THE AUTHORS

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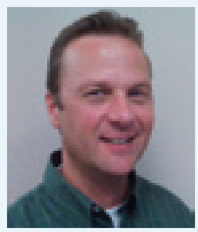


Scott Stein is a Principal Consultant with Enspiria Solutions, Inc. – A Black & Veatch Company. He has 19 years of experience in utilities AMI systems and wireless/telecommunications, with particular expertise in AMI deployment and systems integration. Scott holds a BS in Telecommunications Management and is a certified Project Management Professional (PMP). He formerly held positions with Landis+Gyr, eMeter, and Cellnet Data Systems.

Circle 5 on Reader Service Card

A Platform Approach to Unifying Gas, Water and Electricity Management Systems at Public Utilities

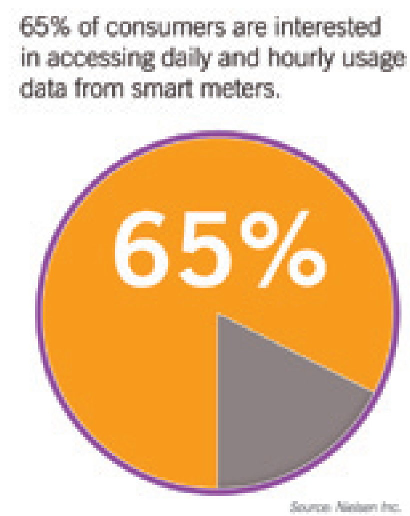
By Matthew Burkmier, CTO, Calico Energy Services and
Thomas Hulsebosch, Managing Director, West Monroe Partners

When gas, water and electricity usage can be monitored, measured and managed collectively in one cohesive framework, publicly owned utilities can improve conservation, help their customers save money, reduce administrative costs and better prepare for increased demand from population and/or industrial growth.

Did you know that approximately 20 percent of all electricity is used in the treatment and distribution of water? Sourcing, moving and treating this precious commodity has a significant impact on our overall energy supply and usage. Yet while water and energy production are inextricably linked with consumption, the management of the associated sets of systems and resources are typically Balkanized at the utility level.

At utilities that manage multiple resources, such as gas, water, wastewater and electricity, these commodities are generally managed by separate divisions. They may each have their own infrastructure, pricing, service teams, billing, and management systems.

But customer survey results tell a different story: according to recent research by Nielsen Inc.[1], 65 percent of consumers are interested in accessing daily and hourly usage data from smart meters. Far from viewing these as separate systems, consumers are actively seeking a single view of their consumption of resources. Almost 90 percent of these consumers are willing to pay for access to their energy data: 15 percent would pay as much as $10 per month; 27 percent would pay $5; and 47 percent are willing to pay at least $1.



Utilities can extend detailed energy usage info to customers using energy data management.

Unfortunately, the fragmentation of gas, water and electricity systems makes it challenging to provide customers with a single application to view resource usage. More importantly, segmentation of data also makes it much more difficult for utilities to efficiently manage these resources cohesively or to make swift, data-driven decisions. In addition, each separate system carries its own individual overhead, management, and administrative costs, all of which hampers customer service.

Employing a platform approach to resource management can overcome these challenges. An emerging set of technologies are being deployed by leading utilities to residential and commercial customers that provide a single view of water, gas and electricity cost and usage. These solutions are designed to “glue” existing legacy systems together, streamline energy and demand-side management programs and provide customers with a single, consolidated view of their consumption. The operational cost savings alone in this unified approach is highly compelling – not to mention improvements in customer satisfaction and active engagement in managing their conservation.

[1] ESource and Nielsen Energy. Customers Want Smart Meter Data and Are Willing to Pay For It. June 2011.
http://www.esource.com/esource/getpub/public/pdf/press_releases/ESource-PR-SmartMeterData-6-11.pdf

Smaller rural and/or cooperatively-owned utilities are uniquely positioned to benefit from these changes. At a basic level, they are much more likely than their larger metropolitan brethren to be the sole-source provider for gas, water and electricity in their particular coverage area, thereby making this unification feasible. Since they are owned by their customers, co-op and municipalities are focused first on customer cost savings rather than profitability, which aligns well with the efficiency improvements derived from unification. This unification increases the opportunity to be more proactive in customer service, conservation programs and communication, which matches the customer responsiveness and focus found at the co-op/muni level. But before embarking on any unifying initiative, utilities need to develop and begin implementing a strategy for customer engagement as it is ultimately the customer response and adoption that will determine success (see sidebar).

From a cost perspective, unification must be able to tie existing legacy systems together, as anything that requires a wholesale "rip-and-replace" approach is likely to be too expensive and disruptive to get off the ground. Utility decision makers and planners should look for software that is standards-based as well as device-agnostic – and therefore designed to work across existing infrastructure. Beyond pure cost reductions, the benefit of this approach is four-fold; that is, utilities can 1) save money by extending previous technology investments, 2) reduce administrative and customer service workload, 3) incorporate proven new technologies as they emerge, and 4) significantly reduce roll-out time and complexity.

Of equal importance in a successful integration strategy is the people and processes that will be employed throughout a program lifecycle. In order to successfully complete a multi-resource integration and maximize the benefits of available technologies through energy management programs, a utility must have buy-in from its management team, as well as affected groups in the organization. IT, Program Management, Customer Relations, Customer Care, and Field Teams must have the capacity to handle the additional workload – or at least a committed strategy to augment them – during a program implementation lifecycle.

From a process standpoint, implementing a management platform, and integrating it with the various systems used by these groups and to unify the customer and utility view of gas, water and electrical systems, can be broken down into the phases described below.

Utilities can follow a proven path to integrating water, gas and electricity management systems.

1: Assessment

The first step in assessing the needs and requirements for an energy and resource management platform is to assemble a team who can identify the relevant business drivers, objectives, and priorities. Often, these objectives span multiple lines of business and/or departments in the organization, so taking the time to include all of the relevant stakeholders dramatically improves the business case and total value. Without such an assessment, it is difficult to prioritize implementation or ensure that the scope of the project will be appropriate to address current and future needs. Consider hiring a consulting firm with a track record in managing successful utility deployments and technology selection.

2: Technical Gap Analysis

Once an organization's energy/water data management objectives and requirements are clearly understood, the assessment team needs to survey existing systems and conduct a thorough gap analysis to identify additional technical components and capabilities that are needed to meet the business objectives. This gap analysis should map all current and required data sources – both internal and external. This will also help clarify which systems, users, and customers will be affected by the new management platform, aiding preparation and outreach.

Then, based on the gap analysis, the team can utilize the functional and business requirements documents it creates to identify available management platforms, and fully understand the benefits that these technologies can provide. This can be done either through an RFI process, or by hiring an industry expert who can serve as a strategic advisor to the team. The key to success with either strategy is to be as specific as possible about the utility's needs, and to leverage lessons learned from previous utility projects.

3: Building the Business Case

Once relevant technology options have been identified, the team should determine organization-specific benefits that can be realized by unifying utility data and enabling better decision-making based on analysis of that data. What new services and applications could be enabled by the management platform?

What conservation programs could optimize the consumption and management of energy by aligning energy use? What administrative burdens could be eliminated? What regulatory requirements could more easily be met? What risks and costs could be avoided?

For example, progressive utilities like the Cucamonga Valley Water District in Southern California are working with major water consumers (e.g., agricultural irrigation) to shift the time of day during which they consume water away from peak electricity usage periods. Since the pumping and distribution of water requires a great deal of electricity, and the production of electricity requires water, these relatively simple programs create a virtuous cycle of conservation.

In addition, a unified resource management platform typically requires 60-70 percent less staff time for management, which fits well with lean staffing requirements at smaller utilities and allows for resources to focus on other priorities. Combining a unified data management system with advanced metering infrastructure (AMI) systems also helps administrators unlock and utilize the vast flow of data that these devices provide, and take action to better manage energy. This can result in fewer truck rolls (resource savings), and give immediate and granular insight into gas or water leakage, power outages, etc., thus, allowing utilities to pinpoint problems before customers call, and thereby improving service.

The biggest change value in smart grid data transformation occurs when disparate and disjointed technologies and systems are integrated, empowering the utility to conduct a broad variety of analytics about usage and offer advanced management and conservation programs that benefit both the consumer and the utility.

Selecting the Right Technologies

Generally, the largest set of customer and utility benefits are realized by deploying a unified energy services, data management, and command and control platform that is flexible by design, and easily connects to the Smart Grid, back-end systems, and applications. It should have the ability to bridge multiple data systems, broker communications between legacy systems and hardware, and extract, analyze, and display meaningful and actionable usage information.

Such a platform needs to be able to adroitly handle any combination of commercial and residential gas, water and electricity data and metering devices. Just as importantly, it can't be limited to proprietary hardware devices and protocols, as these significantly limit future flexibility.

As utilities with recent smart meter deployments are quick to point out, having access to data is not helpful without the ability to analyze and react to it. For this reason, a key component of any successful platform is a robust and flexible analytics and reporting engine, which provides both regular, ongoing reporting – as well as ad-hoc reports for different departments throughout the utility enterprise.

Additional Unified Management Platform Benefits

Besides the data that a unified management platform can pull from other systems, it should also be able to "push" control signals, pricing data, and a variety of other outputs to external devices, web portals, and displays in order to fully optimize the utility's ability to manage delivery. This two-way communications network will also provide a great deal of flexibility for monitoring, measuring, and controlling distributed generation, storage, and renewables as they come online in the future.

A unified management and analytics package will also support valuable new initiatives for the utility, including:

The ability to drive automated Demand Side Management decisions. Advanced management platforms can utilize analysis of prior usage patterns, weather predictions, pricing feeds, and a variety of other attributes to automate savings for the customer and alleviate shortages in supply.

Analysis and optimization of micro-grids. With a strong platform in place, utilities can analyze specific segments of their service territory based on existing infrastructure, demand, and supply. They can also deploy specific programs and strategies to optimize localized usage patterns, reduce bottlenecks, and improve quality using distributed generation or pumping, renewables, storage, and other assets.

Targeted demand response and price response programs. Utilities can drive Demand Response programs at the customer, transformer, substation, or feeder level in response to isolated spikes in demand or intermittent supply from renewable energy sources.

Intelligent efficiency. Using comparative analytics and device-level usage patterns, utilities can proactively notify customers when their appliances exceed an average usage level, and provide an incentive for the customer to replace that device. In addition, efficiency programs can be better targeted to each customer based on a detailed analysis of their consumption patterns, device types, etc.

Validation of optimal rate and customer program combinations. Based on the data and customers within a service territory, utilities can validate which combination of rates, incentives, and programs can best enable both customer savings and managed supply and demand.

Optimized support for electrical vehicle adoption. Unified energy management programs can dramatically help utilities shift electrical vehicle demand to off-peak hours, ensure system reliability, and offer compelling rate programs. Customers thereby gain the ability to choose when, where, and how fast to charge their vehicles.

Conclusion

In short, combining water, gas and electrical systems under a unified data management platform – one with both an open architecture and modular components – facilitates the ability of utilities to meet existing service requirements and future Smart Grid deployments. It can save money for the utility and its owners, and improve resource utilization and efficiency programs. And ultimately, the new platform provides a unified set of utility services, including: rates and rate modeling, pricing and billing services, demand response, analytics, device management, efficiency or conservation programs, and customer support.

Moreover, this combination of openness and modularity makes integration with existing meters, data streams, and applications straightforward and cost-effective. The end result is a powerful, unified view of water and energy data, and dynamic reporting that helps utilities and their customers make the most informed usage and conservation decisions. ■

ABOUT THE AUTHORS

Matthew Burkmier currently serves as Chief Technology Officer for Calico Energy Corporation. In this role, he drives the overall technology strategy for the company with a core focus on technology solutions that help enhance the efficiency of the energy grid and improve the services that utilities provide to their customers.

Thomas Hulsebosch is responsible for developing and leading West Monroe Partners Energy & Utilities practice. He is a 20-year veteran of the wireless telecommunication industry with extensive experience creating and delivering solutions for enterprises, public safety agencies, and service providers.

Planning for Customer Engagement

Few utility management initiatives that involve consumers will succeed without a well-executed customer engagement strategy. In order to ensure that any unification and management platform implementations are successful, utilities should begin to engage customers before technologies have been selected or implemented. In addition, hiring a consulting firm that specializes in customer engagement will help a utility to learn from the industry's previous mistakes, rather than repeating the hard earned lessons of those that have come before.

Today, residential customers take water and energy for granted, and have limited awareness of how to conserve it. This makes it difficult for utilities to drive customer awareness and adoption, which limits their ability to effectively control demand. In many respects, the key to residential customer engagement lies in providing a compelling reason for the consumer to care. In three minutes or less, can the customer identify how much money they can save? How their usage compares to their neighbors? How to automate savings so they don't have to think about it?

Engaging customers in reducing and/or shifting consumption requires a systematic, strategic approach – as well as mature, user-friendly technologies that automate conservation while allowing customers to choose their level of participation in relevant programs. While this is something utilities have struggled to do effectively in the past, there are consulting firms that have successfully helped utilities accomplish this goal.

If correctly chosen and implemented, unified management platforms can enable utilities to tap data from disparate systems to provide actionable, engaging information to customers – while creating a single point of control for the utility. Technology systems that leverage strong usability, in-context help, visual displays, predictive cost savings calculators, and the ability to obtain relevant energy efficiency tips are particularly powerful in engaging customers for the long-term.

Volume 6 No. 2

With William T. (Tim) Shaw
PhD, CISSP

SECURITY SESSIONS

What did you mean by what I think I heard you say?

Welcome to the next installment of *Security Sessions*, a regular feature focused on security-related issues, policies and procedures. Over the past few years I have worked with both IT folks and I&C folks to bridge the "gap" that exists in the expertise, and quite often the terminology, of the two communities. Sometimes it seems like the two groups don't even speak the same language. And to a large degree, I guess that is actually true. Like it or not, I&C personnel need to learn about and understand the 'lingo' of IT so that they can have meaningful conversations. It's kind of like when my wife tries to tell me about a problem with her laptop PC (or the car.) She and I don't use the same terms and when we seem to be using the same terms it often turns out that we mean totally different things. A common basis for understanding and communications are essential for collaboration and collaboration with IT is essential for establishing and maintaining adequate cyber security for our industrial automation systems – ***Tim***.

By now most of us are aware of how industrial automation systems have evolved and transmogrified into things that look frighteningly like IT business systems. They are built out of PCs and "servers" and switches and routers. They run Windows and Linux and Oracle and Apache. We have centralized RADIUS and Active Directory authentication and "policy" servers. We accessorize them with firewalls, and "security appliances" and NAC appliances and IDS/IPS systems. They use Ethernet and TCP/IP and UDP and EtherNet/IP and OPC communications. We implement black listing and white listing and grey listing and…"lions and tigers and bears, oh my!" I could keep on going, using lots more techno-terms, but the point of all of this is that we toss these terms and words around while most I&C people are never given the additional education they really need to truly understand what these things mean, how they work and how they play together. And that is dangerous when, for the most part, it is still the I&C staff that is expected to keep these systems up and running.

One of the things I do in my copious spare time – other than writing these articles – is teaching various courses for the International Society for Automation (ISA). Although some courses I teach are still on basic I&C and computer-based control and automation topics, more and more courses are oriented towards what I like to call "IT survival basics for the I&C staff". It is interesting to take a group of highly competent automation/I&C personnel and guide them into the wondrous world of "how this stuff really works". Just showing them how much hidden functionality is supported in a basic Ethernet switch can be an eye-opening event.

Most of my latest students were not aware of the fact that a network of interconnected Ethernet switches will intercommunicate and coordinate and automatically respond to network changes/failures (using "rapid spanning tree" messages) and that this functionality is pretty-much standard in most switches. Imagine their surprise when we disconnected an Ethernet cable and watched the flurry of message traffic initiated by that simple act.

Likewise, they didn't know that the essential configuration settings in that same switch – which are necessary for the switch to function – could be manipulated using SNMP communications and freely available software tools, from across the network. Or, that the only thing preventing such manipulation was a set of built-in passwords (called "community strings") that had universally-known default factory settings (i.e., the words 'public' and 'private') until specifically changed. They also did not know that a special type of connection (a "trunk port") must be used between interconnected switches in order to make VLANs work – and most did not know what a VLAN was or even why it was useful. To most of them a switch was just a box with several RJ-45 jacks into which you can plug in Ethernet cables so that computers can talk to each other.

My point is that these are basic "survival" issues for today's I&C engineer since switched Ethernet LANs form the basic backbone of all modern DCS and PLC automation systems. Today, in the same way that an I&C engineer needs to be knowledgeable about PID loop tuning, instrument calibration and sequential function charts, that same engineer needs to have a firm grasp of basic IT concepts and technologies. Those same students, when initially asked if they knew the difference between a hub and a switch (prior to being taken through the course training material) basically could not explain what made them any different. When asked what they thought was meant by a "managed" switch, they figured that it had to do with a manufacturer's support contract or the fact that IT was responsible for the switch, which I suppose is somewhat correct, but that's really not the primary issue of concern as regards cyber security.

Now, at this point you might be thinking, "but the IT folks are responsible for all of that stuff, so we don't need to know about it." That has been the general consensus to this point in time. But, as I mentioned earlier, in many plants support of the automation systems falls on the shoulders of the I&C staff – at least partially because they fought long and hard to keep the IT people from touching those systems. But there may not be IT support staff available on a 24/7 basis, so unless a problem happens during normal working hours it will be up to the I&C people to take the proper corrective actions. Not understanding about trunk ports and VLANs could result in an engineer mis-wiring a replacement switch, or not making necessary VLAN settings, and having communications blocked between system components.

For example, I was recently at a plant where the I&C engineers described a strange and transient problem with their network. They were making Ethernet wiring changes to add a new switch in another plant area when, for no reason, they could understand, the communications all stopped for a few seconds, and then recovered. They had been able to recreate the event, but could find no hardware reason to explain how changes made in one plant area could cause the whole network to be impacted. When I asked about Spanning Tree they told me that they didn't use that vendor. (Maybe now you catch my drift about needing basic IT skills?)

Sure, you can have a lot of carefully written and tested procedures that could take that same engineer through the steps needed to replace a failed network component without their having to understand the steps. Or, you could rely on the backup/redundant system elements to keep you operating until the IT support staff shows up. But I personally feel it is best that the I&C personnel receive essential IT training.

I am of the same opinion as it relates to having I&C people understand the concepts of cyber security and all of the fancy technical controls and countermeasures that IT will sprinkle around a plant to make it secure from cyber attack. One of the challenges for I&C personnel – and even for some IT folks – is the mind-numbing array of meaningless pseudo-technical marketing gobbledygook that is used to "explain" and "differentiate" various kinds of techno-toys. Believe me, I've read and re-read those so-called technical brochures on high-tech products for equipment such as intrusion detection and prevention systems and walked away feeling that I had no idea what they did, how (or if) they worked, or how they could (and could not) be applied. Although I wasn't entirely sure what they meant by a 'platform' from reading their literature, I sure knew what kind of 'per-platform' licensing fees they wanted to be paid!

In their rush to bring forth their techno-panaceas and capture the market, while cyber security is still the hot topic of the day, some companies are doing a disservice by letting their sales and marketing staff explain their products to the masses. From my viewpoint at least, they are doing a poor job.

In some of my ISA courses we have reviewed marketing literature for cyber security products, and it is always interesting to see the class reaction. For example, I've had students tell me that if we had not discussed what a firewall did and how they generally work, they would never have come away understanding it from reading the sales literature we reviewed. In my opinion, any I&C engineer that can't come to a course and is left to figure it out on their own by reading vendor product literature has a great challenge ahead of them. One would think that by attending one of the endless parades of on-line product webinars you could gain the requisite knowledge and understanding. In my role as a contributing editor, I've signed up and participated in quite a few during the past year.

And while we're talking about professional associations, you may be interested in a new ISA certification activity that was launched as an offshoot of the activities of the ISA-99 industrial cyber security committee and working groups. (I should note for transparency purposes that I participate as an observer on that committee). They have established a set of manufacturer/vendor requirements and testing through which a product can be certified.

Quoting from the ISA website: "The ISASecure designation is earned by industrial control suppliers whose products demonstrate adherence to an industry consensus on cyber security specifications for security characteristics and supplier development practices." To begin with, they seem to be focusing on instrumentation and controllers with their Embedded Device Security Assurance (EDSA) certification, which can be obtained in one of three (3) levels of increasing security assurance. But in order to obtain certification for a specific product, the manufacturer must submit to a Functional Security Assessment (FSA), a Software Development Security Assessment (SDSA) and to Communication Robustness Testing (CRT).

Although this is a fledgling program, and there will undoubtedly be issues and challenges, it is a good starting point in addressing the challenges of supply chain protection. (See my last column for a discussion of supply chain issues.) Of course we will have to see how rigorous they are in their software development security assessment process, particularly as regards embedded firmware that comes already installed in basic building block integrated circuits. If that software isn't being included – and I don't know that it isn't – then the SDSA process is seriously flawed. But that will be the subject matter for a future column... ***Tim***

ABOUT THE AUTHOR

Dr. Shaw is a Certified Information Systems Security Professional (CISSP) and has been active in industrial automation for more than 30 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 and has also contributed to several other books. 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 *Tim@electricenergyonline.com*.

Leveraging the PMO for a Changing Power Grid

By Nancy Y. Nee, PMP, CBAP, CSM
Executive Director, Project Management &
Business Analysis Programs, ESI International

> *"The move to a smart grid requires utilities to raise the bar and attain a higher level of sophistication when it comes to project management. Specifically, a project management office will help utilities train and support their workforce to implement the type of transformational change needed to achieve collaborative and cross-functional teams, implementation of innovative technologies, and transparency with customers."* – Julie Zinn Patti, Director of Operations, Spirae (Ft. Collins, Colo.)

In the comments above, Ms. Zinn Patti points out that utilities are at varying stages of implementing solid project management teams, much less an established enterprise-wide project management office (PMO) – but the benefits are worth the effort for tackling one of the industry's greatest challenges. Indeed, the transformation of our energy infrastructure is underway, spurred on by increasing power demands, the quest for energy independence, aging systems and federal incentives via the American Recovery and Reinvestment Act (ARRA) to deploy smart grids.

But for an industry built on reliability of service and tradition, the move to a smart grid requires the ultimate in change management. Utilities will need to break down internal barriers and develop a team approach. That means bridging the service, IT and operational side, transitioning to a cutting-edge, distributed, two-way data system demanding interoperability, and all the while, executing outreach and educational programs to avoid customer backlash.

Defining the PMO

There is no "one-size-fits-all" PMO. Each PMO is as unique and specific as the corporate culture it supports. However, it is worthwhile to define generally what a PMO is and what it does.

According to the *Dictionary of Project Management Terms, 3rd Edition*, a project management office is an "*organizational entity established to assist project managers throughout the organization in implementing project management principles, methodologies, tools, and techniques.*" (Ward, 349)

The PMO is the instrument through which an organization successfully deploys project management. A PMO, like project management itself, is a means to an end, not the end itself; and, as such, it is strategic in its purpose and objective.

The "end" is whatever business outcome and results the organization has identified as being critical to its survival. This, in the case of utilities, is boosting overall performance in project and program management to create a dynamic, decentralized distribution system.

PMO Study Highlights Best Practices

In March 2011 ESI International undertook an investigation into the global state of the PMO to determine its current perceived value, effectiveness and role as a hub of training by asking the following:

- Do organizations even know whether their PMO is effective?
- Is it deemed valuable to the enterprise as a whole?
- Is the PMO really a Center of Excellence in which best practices are identified and made available to their project managers?

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GUEST EDITORIAL

The published ESI report titled, *"The Global State of the PMO: Its Value, Effectiveness and Role as the Hub of Training"*, encompasses 3,740 senior level project and program managers from five continents in over 16 industry sectors including utilities, and offers insights into the PMO from both a PMO and non-PMO staff perspective.

No matter where a utility company is in the development of a PMO, the study's findings can serve as a roadmap for developing and/or refining a PMO and a reference guide for industry best practices.

PMOs as a Hub of Training

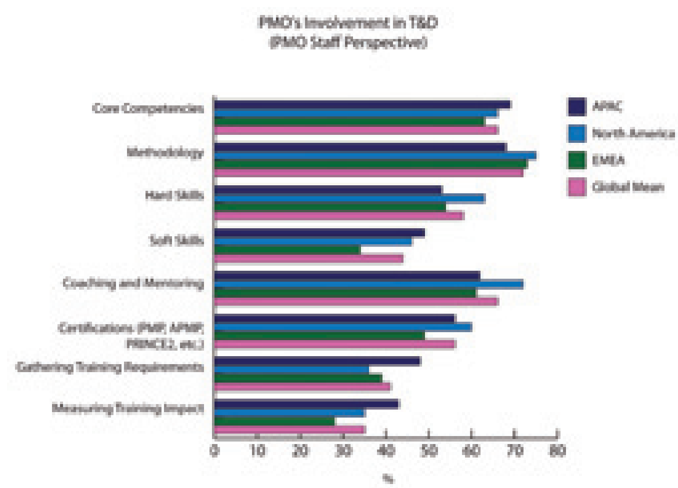
The study shows that there can be a strong disconnect between the PMO being seen as a positive force in the initial training of project-oriented staff and then ongoing career management.

Utilities should ensure that PMOs clearly communicate the value of knowledge transfer, the importance of succession planning conducted through mentoring, and the very fact that training is available and encouraged.

From a global perspective, the study shows that the PMO is strongest as a training hub for methodology and tools (78.2 percent), followed by other hard PM skills such as planning, scheduling and risk management (51.2 percent). Coaching and mentoring (46.1 percent) and other soft skill training (42.6 percent) lag behind considerably.

PMOs need to make sure they place equal importance on hard and soft skills, such as leadership and critical thinking, for training and development in order to have a positive influence on career progression.

How does the PMO get involved in the training and development of project-related staff?



How does the PMO get involved in the training and development of project-related staff?

Measuring PMO Effectiveness

A key finding in this study is the lack of measurement for PMO effectiveness in most of the world. Three out of four non-PMO staff say that their organization either does not measure or they do not know whether it measures PMO effectiveness. In fact, more than half do not measure PMO effectiveness at all.

On a global level, 73.3 percent claimed the PMO communicates and reports its own effectiveness through projects delivered on time and to budget while 66.4 percent claimed PMO effectiveness was expressed through an increase in successful projects. Almost 61 percent pointed to customer satisfaction.

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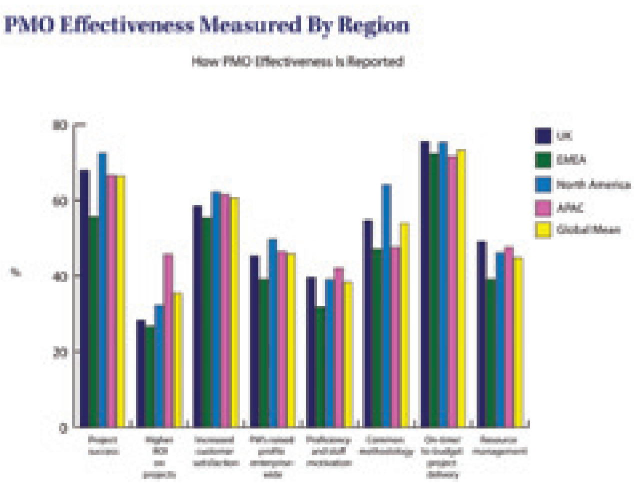


How PMO effectiveness is reported

The findings reinforce that for those that do measure PMO effectiveness, delivering projects on time and to budget is very much the main measuring stick for PMO effectiveness worldwide, yet that is only one piece of the PMO effectiveness puzzle. Success has not only to do with on-time and to-budget project delivery, but also with client satisfaction.

Role and Value of PMO

When asked what role they think the PMO should play, nearly an equal number of PMO (22 percent) and non-PMO (23 percent) staff members agreed it should fulfill its role as a center of excellence. From the PMO staff member perspective, nearly half claimed it should be involved in some level of project management.

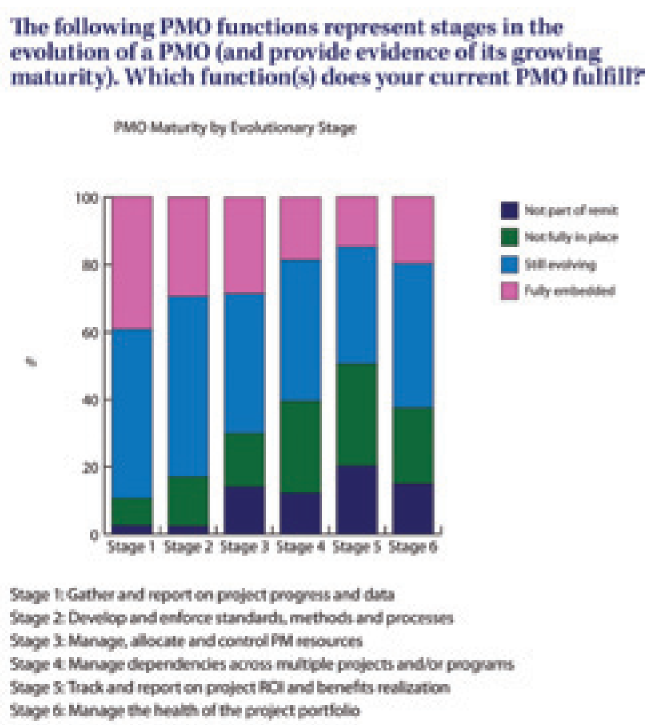
From a value perspective, the top three areas in which the PMO is most valued comes in the form of improved workflow, risk management and the provision of tools and processes.

Nurturing the PMO

As PMOs develop and mature, they will advance from the beginning stages of gathering and reporting on project progress and data (stage one) and developing and gathering standards, methods and processes (stage two) to full maturity at stage six, which is portfolio management.

The study finds that only one in five PMOs is operating at the strategic level worldwide. In fact, only 20 percent report they engage in portfolio management, and 15 percent report that they track return on investment and benefits realization. Of all six stages of PMO maturity, PMOs are strongest in reporting on projects (stage one) and the weakest on determining project ROI (stage five).

Utilities will benefit most from a PMO that progresses and matures over time through all six stages, becoming increasingly more sophisticated and deeply entrenched in corporate culture.



Shows the 6 stages of PMO maturity

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GUEST EDITORIAL

PMO Study: Lessons Learned

When reflecting on the past 12 months, survey responses indicate that the top three challenges facing PMOs include process, scope and methodology adoption; stakeholder buy-in; and a lack of resources.

The study also points out that PMOs need to be able to adjust and respond to changing organizational needs. Make sure your PMO can:

- Fine-tune its ability to adopt training models that best serve organizational needs by measuring ROI.
- Continue to increase the perceived value of the PMO to the organization by evolving in step with the rest of the organization.
- Improve enterprise-wide communication to reinforce its value.
- Garner executive level support and buy-in.

Establish the Business Value

No matter where utilities are on the PMO journey, PMOs must clearly establish and prove its business value. One way in which utilities can improve their chances of PMO impact is to establish formal effectiveness measurements on both the training and PMO levels.

By implementing both pre- and post-training assessments, PMOs can foster their role as the hub of training for everyone in the organization while reinforcing their value. By measuring for PMO effectiveness, organizations can leverage the PMO not only for tactical project support, but also for more strategic, enterprise-wide professional development.

A changing power grid means a changing workforce. Establishing and nurturing a PMO can be a strategic step toward providing the coaching and mentoring, along with other soft skills training, needed to invest in tomorrow's leaders today.

ABOUT THE AUTHOR

Nancy Nee (PMP, CBAP, CSM) is Executive Director, Project Management & Business Analysis Programs for ESI International and brings more than two decades of PM and BA experience in healthcare, information technology, financial services and energy to ESI's learning programs. As a SCRUM master and expert in Agile PM, Nancy also has a strong background in strategic enterprise architecture, project governance, business process analysis, continuous process improvement and automated solutions.

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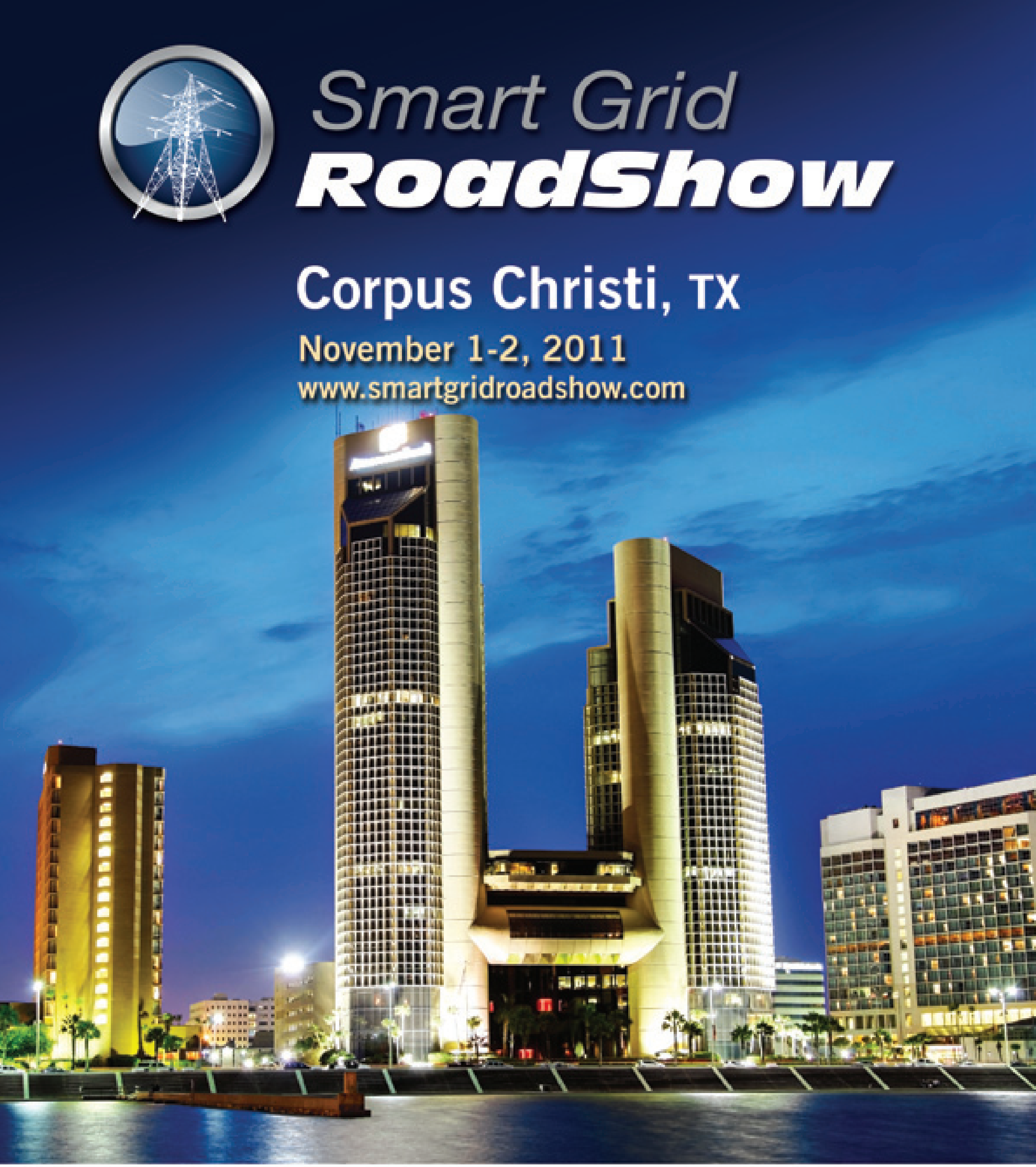

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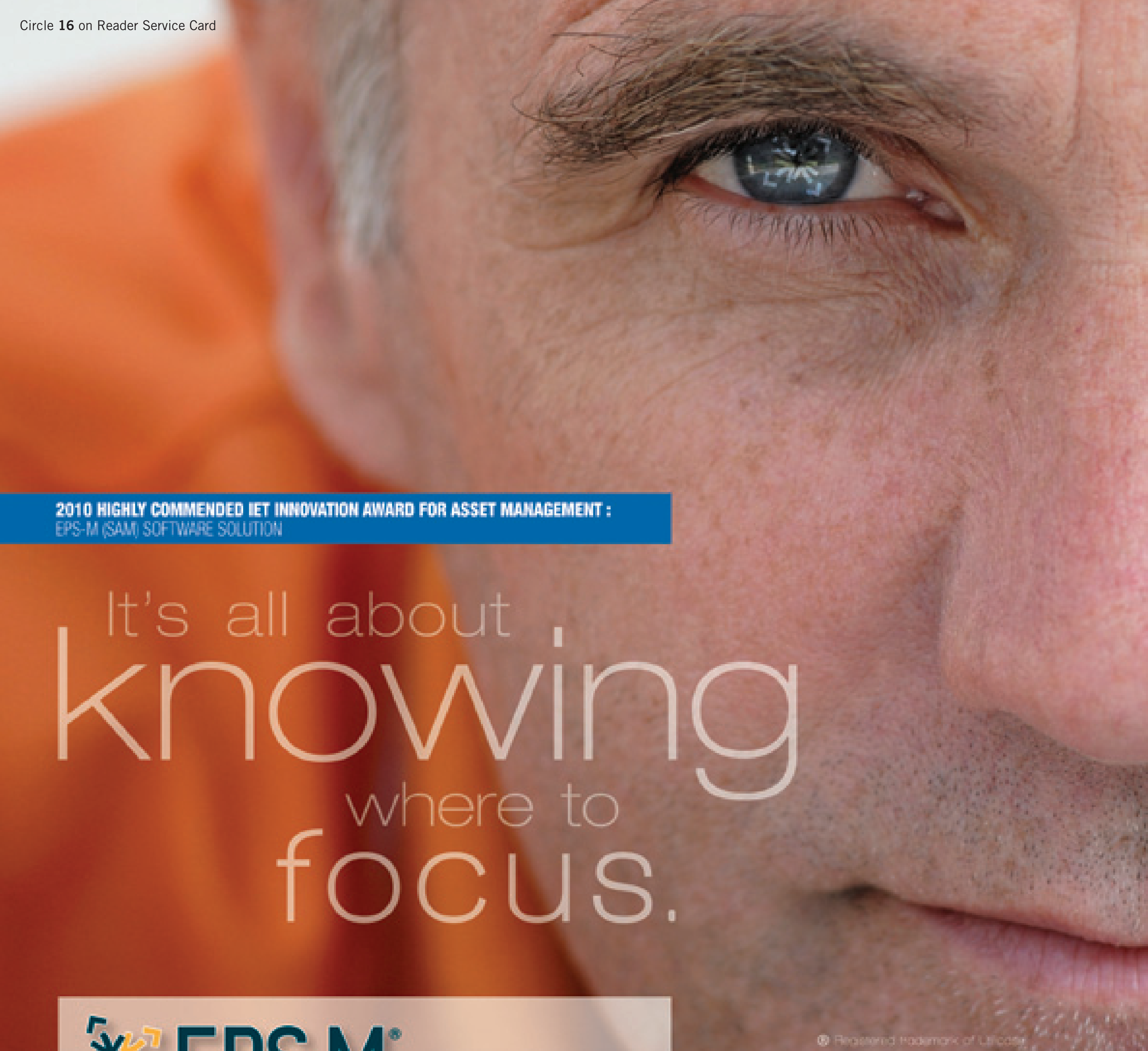

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