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Electric Energy T&D MAGAZINE

JANUARY-FEBRUARY 2011 Issue 1 • Volume 15

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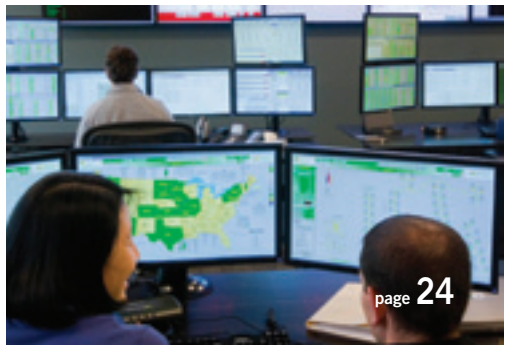
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Electric Energy Magazine is published 6 times a year by: Jaguar Media Inc.
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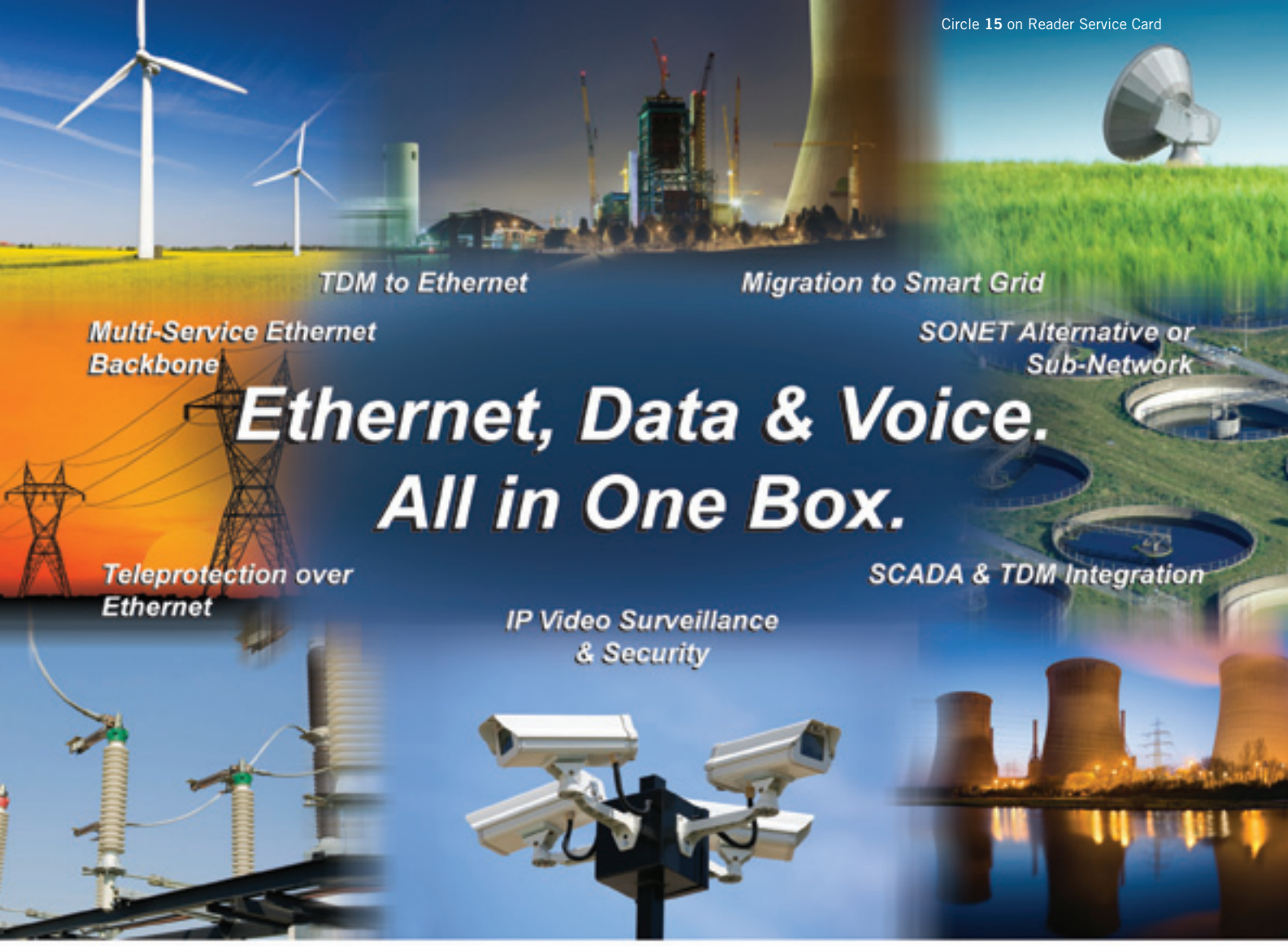
***Electric** Energy T&D Magazine* Serves the fields of electric utilities, investor owned, rural and other electric cooperatives, municipal electric utilities, independent power producers, electric contractors, wholesalers and distributors of electric utility equipment, manufacturers, major power consuming industries, consulting engineers, state and federal regulatory agencies and commissions, industry associations, communication companies, oil & gas companies, universities and libraries.

Post Publication mail agreement #40010982
Account #1899244

COVER PAGE IMAGE: IStock Photo



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GridLines

Michael A. Marullo,
Editor in chief

The Case for Grid Transformation

(Or: 2-4-6-8... the time has come to automate!)

Sometime between Halloween and Christmas it occurred to me that, as an industry, we really need to move forward in this new year on a substantially different path than the one we've been on for the past several. The path we've been on is the one where "Smart Grid" implies that the grid is currently not very smart at all, and the one where 'Smart Grid' is merely jargon for 'Smart Metering' – and vice-versa. I respectfully submit that we need to change our vernacular AND our course of action to something that, at the very least, transcends the tendency to use the terms "Smart Grid" and "Smart Metering" interchangeably.

In my view, continuing to use these terms to express the broadest needs and goals of a 21st century power delivery network is at best misleading, and at worst, downright detrimental to the greater good that I'm sure we all intend. And, as far as I can tell, no two people or organizations have the same interpretation of what the term "Smart Grid" even means. This is understandable, however, since it legitimately means different things to different people, based on their individual circumstances and a variety of other legitimate variables.

So instead, I suggest we start using the term "Grid Transformation" to embrace and embody ALL of it. I maintain that what we need to do is TRANSFORM – i.e., repair, replace, redefine, reinvent, reinforce, redesign, modernize, upgrade, improve, enhance (or whatever other superlatives you want to tack on) the grid. What we should NOT be doing is only one or just a few of those things – we need them all, but that will take time and money, both in very large amounts and neither of which we have immediately available.

With this concept in mind, let's focus for a moment on what this terminology change means in the greater scheme of things. As has often been pointed out, "Smart Grid" implies that the grid is currently "dumb" (it isn't!) and "Smart Metering" has a way of implying that it's a fix-all for everything that ails the grid (it is NOT!).

And just to reinforce the point, no amount of Smart Metering is ever going to repair, replace or upgrade old power lines or aging circuit breakers, switches, transformers, etc., so let's not perpetuate the notion that it will. I suggest to you that Grid Transformation is what we need... Smart Grid and Smart Metering are both peripheral to that cause and purpose. Can we all agree on that? Good.

Now that I've gotten that of my chest, I'm happy to say that I'm already seeing a light at the end of the tunnel. And the really interesting part is that this light is coming from a place where one might least expect it: Smart Metering companies.

Really. Have you noticed that the latest advertising messages coming from most, if not all of the major meter manufacturers – as well as a substantial number of the supporting communications network technology providers – has recently shifted away from Smart Meters to talking about end-to-end solutions for things like Distribution Automation, Distribution Management and so forth? Hey, I'm not knocking it; those are exactly the right things to be talking about. And not only are they talking about it – they're doing it. These are some really bright people. They've taken what they've learned, and now they're applying it on a broader scale.

So let's talk about what Smart Grid – or better yet, "Grid Transformation" – really IS about. First off, it's all about power delivery. Yes, without generation we wouldn't need power delivery networks, but unlike the wires business, historically a lot of money has been thrown at generation. T&D investment? Well, not so much. It's a very complicated issue, but let it suffice to say that the economic incentives for building more T&D as opposed to building more plants has historically been a far cry from parity.

Also, we haven't been taking very good care of the grid we have. Rather than investing in it as the vital infrastructure it is, it's been widely regarded as a necessary evil; something simply put in place to bring those electrons to market. A vital *expense*, yes – a vital long-term *investment*, no. And just like the guy who buys cheap tires for his limousine, the vehicle still stops abruptly when a tire blows, and he hits the wall.

Today, that's really where we are. We've managed to make do by skimping on T&D investments for at least a couple of decades, and we've lulled ourselves into thinking that we can just keep going back to that well indefinitely. That fact is, we can't. The grid needs to stay reliable and vibrant and also become substantially more robust if we're going to accommodate all of the new demands for things like electric vehicle charging, grid storage and renewables integration – just to name a few – while at the same time preserving and enhancing grid reliability; improving flexibility and capacity; and, of course, protecting its security and integrity.

That's already a tall order, but at the same time, we're also facing a declining infrastructure as well as an aging work force, a huge portion of which has already begun to retire, leaving a serious void of experienced personnel. As an old friend of mine likes to say, "With most of the grid infrastructure now 35-50 years old, we're on the backside of the bathtub curve when it comes to reliability!"

Basically, that means that things can only go downhill from this point forward, absent an aggressive reinvestment plan. So what to do? Well, just like an old car with high mileage for which there is no money to replace, we do the next best thing. That is: Monitor more closely, maintain more regularly and try to keep from overtaxing the operational limitations. And the only way I know that can effectively be done is to automate – starting now. – ***Ed***.

Get a grip on the Grid

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INSPIRING INNOVATIONS

Tropos – Selected #1 for Smart Grid Communications in 2010
Five Key Trends Driving Significant Smart Grid Market Growth for 2011

Tropos Networks announced that last year the company was selected by more utilities as the company of choice for their smart grid communications infrastructure than any other vendor. New utility customers announced by the company during 2010 include: Avista, Burbank Water and Power, City of Duncan, Glendale Water and Power, and Silicon Valley Power. In addition to these, five other utilities also selected Tropos last year to meet their current and future smart grid networking needs; announcements will be made over the next few months. With Tropos' private IP networks, utilities are building a highly reliable and secure smart grid and economical foundation for aggregating communications for multiple smart grid applications. Examples of smart grid applications for which Tropos is used today include: AMI backhaul, distribution automation, substation security, and mobile workforce

Tropos is experiencing a surge in demand that it believes signals the emerging smart grid market is accelerating and this growth will fuel the company for years to come. This trend is confirmed by many independent industry research analysts as well as the investment banking community, e.g. Pike Research, GTM Research, and Deutsche Bank.

There are five key trends the company believes are drivers that contributed to Tropos' growth last year and will continue to drive its market success in 2011 and beyond.

1. Smart Grid Communications Are Being Built as a Network of Networks – Today, smart grid communications are being architected as of a network of networks, comprised of multiple layers and technologies. From the customer home all the way to the utility headquarters, a mix of technologies will be required in order to be successful. The mix of technologies used will be unique to each utility based on planned applications and the communications requirements of those applications as well as the composition of the service territory (mix of urban, suburban and rural).

2. Distribution Automation (DA) Rollouts Will Significantly Increase – While AMI was the initial smart grid application for many utilities, DA applications provide significant benefits to utilities by increasing power quality and reliability. Unlike AMI, DA does not impact customers directly, making it easier to deploy. Utilities are discovering that wireless networks are clearly the most cost-effective way to deliver connectivity to millions of distribution endpoint devices (capacitor banks, transformers, switches, etc.) as connectivity because they can be rolled out quickly. The requirements for wireless networks connecting DA devices are stringent as of applications are critical and require low latency (sub-20 millisecond) plus high reliability (99.999%). The wireless networks must also deliver end-to-end visibility and management for communications to millions of devices across hundreds, even thousands, of square miles.

3. Private Networks Will Continue to Dominate as the Network of Choice for Smart Grids – Reliability, security, control and cost of ownership are the key reasons utilities are choosing private networks. With a private network, utilities can prioritize individual applications, assuring the most critical or time sensitive are unaffected during a crisis or unusual event versus less critical traffic. Utilities have been vocal about their preference as evidenced by their formal public filings with the FCC. Additionally, based on Tropos' analysis, there is a compelling business case for private distribution area networks when both capital expenditures as well as operating expenses are taken into account. Tropos estimates that the breakeven point for public vs. private networks is just under four years where AMI backhaul is the initial smart grid application deployed. As additional smart grid applications are added which leverage the same network, the breakeven point is reduced dramatically.

4. Distribution Area Networks Are Being Architected to Aggregate Communications for Multiple Smart Grid Applications – As utilities design their smart grid strategy, building an end-to-end network for each application simply doesn't make sense. A single private network infrastructure that can be securely and reliably shared across multiple current and future applications, both today's and tomorrow's, is far more cost-effective in the long run and easier to deploy and manage. An additional benefit of a private network is that, utilities have full control over coverage and capacity enabling them to easily expand as needed.

INTEROPERABILITY

The Journey Starts Here.

The creation of a Smarter Grid - a diverse network of generation, storage and demand all balanced and managed in real time - will be the work of a generation of utility engineers.

At the core of this evolutionary vision is Interoperability; the capacity for distributed components from various vendors to communicate and share appropriate information with speed and security. In an ideal world, every device in the grid will be compliant to the standards being defined today. But in the real-world, utilities will need to leverage their investments in legacy components while embracing the new paradigm.

OrionLX

Enter the Orion Automation Platform. Its ability to simplify integration of legacy devices, filter and convert relevant data to multiple formats, and provide cyber secure communications are what have made it the leading U.S. substation automation platform.

As the only continuously upgradable platform on the market, Orion is an ideal way to bridge the gap between the promise and the reality of the Smarter Grid.

Learn more at http://www.ToolsToGetThere.com

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5. Mesh Network Technologies Will Continue to be a Popular Architectural Choice for the Smart Grid – There are different types of mesh network technologies commonly selected for smart grid deployments such as 900 MHz meshes for metering LAN networks and Tropos' high performance mesh for distribution area communications. Mesh network architectures are self-healing and adaptive, uniquely providing the high resilience and reliability required for smart grid communications.

For more information about Tropos, check out: *www.tropos.com*.

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Duke Energy and Progress Energy to Merge

$26 Billion Transaction Will Create Nation's Largest Utility with a Combined Enterprise Value of $65 Billion; Diversified Generation Portfolio in Six Regulated Service Territories

Duke Energy (NYSE: DUK) and Progress Energy, Inc. (NYSE: PGN) announced that both companies' boards of directors have unanimously approved a definitive merger agreement to combine the two companies in a stock-for-stock transaction. The combined company, to be called Duke Energy, will be the country's largest utility, with:

- Approximately $65 billion in enterprise value and $37 billion in market capitalization
- The country's largest regulated customer base, providing service to approximately 7.1 million electric customers in six regulated service territories: North Carolina, South Carolina, Florida, Indiana, Kentucky and Ohio
- Approximately 57 gigawatts of domestic generating capacity from a diversified mix of coal, nuclear, natural gas, oil and renewable resources
- The largest regulated nuclear fleet in the country.

"Our industry is entering a building phase where we must invest in an array of new technologies to reduce our environmental footprints and become more efficient," said Jim Rogers, chairman, president and chief executive officer of Duke Energy. "By merging our companies, we can do that more economically for our customers, improve shareholder value and continue to grow.

"Combining Duke Energy and Progress Energy creates a utility with greater financial strength and enhanced ability to meet our challenges head-on," Rogers continued.

"This combination of two outstanding companies is a natural fit," said Bill Johnson, chairman, president and chief executive officer of Progress Energy. "It makes clear strategic sense and creates exceptional value for our shareholders. Together, we can leverage our best practices to achieve even higher levels of safety, operational excellence and customer satisfaction, and save money for customers by combining our fuel purchasing power and the dispatch of our generating plants.

"This merger also provides predictable earnings and cash flows to support our dividend payments to shareholders," Johnson added.

Terms

Under the merger agreement, Progress Energy's shareholders will receive 2.6125 shares of common stock of Duke Energy in exchange for each share of Progress Energy common stock. Based on Duke Energy's closing share price on Jan. 7, 2011, Progress Energy shareholders would receive a value of $46.48 per share, or $13.7 billion in total equity value.

Duke Energy also will assume approximately $12.2 billion in Progress Energy net debt. The transaction price represents a 7.1percent premium to the unaffected closing stock price of Progress Energy on Jan. 5, 2011, and a 3.9 percent premium to the closing stock price of Progress Energy on Jan. 7, 2011.

The transaction price also represents a 6.6 percent premium to the average closing stock price of Progress Energy over the last 20 trading days ending Jan. 5, 2011, and a 6.4 percent premium over the last 20 trading days ending Jan. 7, 2011.

Following completion of the merger, officials anticipate Duke Energy shareholders will own approximately 63 percent of the combined company and Progress Energy shareholders will own approximately 37 percent on a fully diluted basis.

The combination is anticipated to be accretive to Duke Energy's adjusted earnings in the first year after closing.

Imagine restoring power after an outage... in less time than it takes to read this headline.

It minimizes the extent and duration of power outages. Cuts the cost of electricity delivery. And all but eliminates consumer complaints that always accompany power outages. Rapid restoration is critical. And nothing restores power faster than S&C's total self-healing solution. Our system gives you the ability to restore service in just seconds...automatically.

IntelliTEAM SG™ Automatic Restoration System places intelligence directly in field equipment, allowing decisions to be made where they are most needed. The moment an event occurs, IntelliTEAM SG uses excess capacity from the nearest available source and automatically performs the most efficient switching actions to restore service to as many customers as possible.

Add to this the award-winning IntelliRupter® PulseCloser. It's a high-performance fault interrupter with unique advanced protection capabilities. IntelliRupter dramatically reduces voltage sags and system stress from short circuits on distribution lines.

And, since communications are critical for making self-healing practical, SpeedNet™ Radios offer extremely robust high-speed communication via peer-to-peer networking. S&C's SpeedLINK™ Radio Network Monitoring Software alerts users to potential problems caused by construction and tree growth before these conditions become issues.

Developing innovative solutions. Harnessing local intelligence. Processing in real time to restore power within seconds. And decreasing the conditions that lead to outages. These are the pillars we have used to bring you the fastest restoration solution on the market as well as a flexible distributed intelligence system that will support your Smart Grid requirements of tomorrow.

To learn more about these as well as our other unmatched Smart Grid solutions, visit **www.sandc.com/imagine-ee**.

S&C ELECTRIC COMPANY
Excellence Through Innovation

Based on Duke Energy's current quarterly cash dividend of 24.5 cents per common share, Progress Energy shareholders would receive an approximate 3 percent dividend increase.

Duke Energy expects to effect a reverse stock split immediately prior to closing, and, as a result, the exchange ratio will be appropriately adjusted at that time to reflect the reverse split.

Structure, Organization & Leadership

When the merger is completed, Rogers will become executive chairman of the new organization. In this role, Rogers will advise the CEO on strategic matters, play an active role in government relations and serve as the company's lead spokesperson on energy policy.

Johnson will become president and chief executive officer of the new company.

Both Rogers and Johnson will serve on the board of directors of the combined company, which will be composed of 18 members, with 11 designated by Duke Energy's board of directors and seven designated by Progress Energy's board of directors.

The combined company will be headquartered in Charlotte and will maintain substantial operations in Raleigh.

Until the merger has received all necessary approvals and has closed, the companies will continue to operate as separate entities.

Customers will see no change in their current electric utility companies including: Progress Energy Carolinas and Progress Energy Florida and Duke Energy Carolinas, Duke Energy Indiana, Duke Energy Ohio, Duke Energy Kentucky, Commercial Power, Duke Energy Generation Services and Duke Energy International.

Approvals & Timing

Completion of the merger is conditioned upon, among other things, the approval of the shareholders of both companies, as well as expiration or termination of any applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976.

Other necessary regulatory filings include: Federal Energy Regulatory Commission (FERC), Nuclear Regulatory Commission (NRC), North Carolina Utilities Commission (NCUC) and South Carolina Public Service Commission (SCPSC).

The companies also will provide information regarding the merger to their other state regulators: the Florida Public Service Commission, Indiana Utility Regulatory Commission, Kentucky Public Service Commission and Ohio Public Utilities Commission.

The companies are targeting a closing by the end of 2011.

Circle **19** on Reader Service Card

Utilities: New Hydro-Quebec Contract to Start Below Current Contract Price

Vermont utilities' new contract with Hydro-Québec will begin in 2012 at rates below the existing contract, which phases out over the next five years. Central Vermont Public Service (NYSE: CV) and Green Mountain Power filed information with the Vermont Public Service Board that shows a starting price of $58.07 per megawatt-hour. The PSB will hold technical hearings on the proposed contract beginning on Wednesday, Jan. 19, 2011.

"We are extremely pleased with the deal we negotiated and with the starting price we will pay," CVPS President Bob Young and GMP President Mary Powell said in a joint statement. "We pride ourselves on providing a low-carbon, high-renewable power supply at affordable rates, and this contract will help us retain a competitive position in the region while helping control the air impacts of our supply."

Under the agreement, which the PSB is reviewing, Vermont utilities will purchase up to 225 megawatts of energy, predominantly hydroelectricity, from H.Q. Energy Services (U.S.) Inc. (HQUS) starting in November 2012 and ending in 2038. HQUS markets electricity from Hydro-Québec's generating fleet, whose output is 98 percent hydroelectric.

While the contract was negotiated by CVPS and GMP, HQUS is also selling energy in selected amounts to every other Vermont utility. Those utilities are Vermont Electric Cooperative Inc., Vermont Marble Power Division of Omya Inc., Washington Electric Cooperative, the Town of Stowe

Electric Department, the City of Burlington, Vt., Electric Department, and Vermont Public Power Supply Authority on behalf of its 13 municipal electric utility members.

The agreement includes a price-smoothing mechanism that will help shield Vermont customers from volatile market prices. This starting price, while for a somewhat different category of power service, is about 12 percent lower than the existing contract's expected 2012 price.

"Any time we can replace something that has served us exceedingly well for decades under pricing terms that are lower while being shielded from the market's high volatility, that is an improvement and a significant accomplishment," Young and Powell said.

"The agreement will provide reasonable price stability and an initial small reduction in the cost of one slice of our power portfolio," Young and Powell said. "This is a very attractive deal for Vermont and a significant accomplishment on behalf of our customers and the customers of the other participating utilities."

Young and Powell thanked the Douglas Administration for its help in working with Québec in the months leading up to the contract signing this past summer, and the Shumlin Administration for its continued support to gain approval from the PSB. "Governor Douglas, Lt. Gov. Dubie and Governor Shumlin have been uniformly supportive of our efforts to produce a valuable contract for Vermonters," Young and Powell said. "There has been a tremendous collaborative effort between utilities, the two administrations and officials in Québec."

Circle **20** on Reader Service Card

Smart Grid Consumer Collaborative Grows to 50 Members

Three consumer advocacy groups, a business services vendor, and one of the nation's largest utilities help new non-profit reach membership milestone

Six new members of the Smart Grid Consumer Collaborative (SGCC) put the nonprofit over its goal of fifty members in its first year. The group, which last week announced its first permanent executive director in Patty Durand, continues to gain momentum with these new members:

San Diego Gas & Electric is one of the nation's largest public electric utilities.

The Alliance to Save Energy, the Natural Resources Defense Council, Green DMV, and the Southeast Energy Efficiency Alliance are environmental and consumer advocacy groups.

Vertex Business Services is a business process outsourcing and IT services company which promotes improved customer experience.

"The SGCC was formed to foster mutual understanding between industry and consumers regarding the creation of a next-generation energy infrastructure," said SGCC Interim Director Jesse Berst. "We've grown rapidly by welcoming utilities, vendors, and consumer groups to listen, educate, and collaborate through research and forums for sharing best practices."

Founded in February 2010, the SGCC's growth highlights a new trend toward collaborative efforts to build a modern electric grid that serves the needs of all stakeholders. SGCC Charter members include General Electric, IBM, and the GridWise Alliance. For a complete list of members, see *http://smartgridcc.org/members.* SGCC's newest members are:

The Alliance to Save Energy is a nonprofit coalition of prominent business, government, environmental and consumer leaders who promote the efficient and clean use of energy worldwide to benefit the environment, the economy and national security.

ASE Senior Vice President of Policy and Research Floyd DesChamps said, "The smart grid has the potential to unlock major energy efficiency opportunities for consumers, empowering them to realize energy efficiency as the quickest, easiest and cheapest road to a new energy future. The Alliance to Save Energy promotes energy efficiency worldwide to achieve a healthier economy, a cleaner environment, and greater energy security. We are pleased to work with the SGCC to ensure that consumers are able to realize the efficiency benefits of smart grid systems."

Green DMV is a nonprofit promoting clean energy and green jobs in low-income communities across America as a pathway out of poverty. Their initial focus is on the Washington, D.C. metropolitan area to help influence policy change in the region that will spur sustainable green job growth and equitable environmental policies.

Natural Resources Defense Council (NRDC) is an international nonprofit environmental organization with more than 1.3 million members and online activists. Since 1970, its lawyers, scientists, and environmental specialists have worked to protect the world's natural resources, public health, and environment.

"NRDC is dedicated to advancing a clean energy economy in an environmentally sustainable manner," NRDC Staff Attorney Brandi Colander said. "To that end, NRDC believes that it is time to consider the adoption of a cost effective smart grid initiative. The existence of an integrated communications infrastructure that corresponds with price signals in real time is potentially valuable to both energy efficiency and renewable energy technologies -- although adroit choices of implementation strategies will be crucial to success. NRDC is pleased to join SGCC to properly explore broader deployment of these technologies and clearly define the benefits that a smart grid can deliver and the extent to which it can facilitate a cost-effective transition to a more sustainable energy future."

San Diego Gas & Electric (SDG&E) is a regulated public utility that provides safe and reliable energy service to 3.4 million consumers through 1.4 million electric meters and more than 845,000 natural gas meters in San Diego and southern Orange counties. The utility's area spans 4,100 square miles. SDG&E is a subsidiary of Sempra Energy (NYSE: SRE), a Fortune 500 energy services holding company based in San Diego.

Southeast Energy Efficiency Alliance (SEEA) promotes energy efficiency for a cleaner environment, a more prosperous economy, and a higher quality of life in the Southeastern region of the United States. Based in Atlanta, and working in eleven states, SEEA brings together businesses, utilities, governments, public utility commissions, energy service companies, manufacturers, retailers, energy and environmental organizations, low-income energy advocates, large energy consumers, and universities to promote energy-efficient policies and practices.

Vertex is a leader in BPO (business process outsourcing), customer management outsourcing and IT Services, serving over 200 clients worldwide across many sectors. Vertex provides value-based solutions that deliver exceptional customer experience -- and do so cost effectively.

"Vertex Business Services is delighted to join the Smart Grid Consumer Collaborative," said Ron Aberman, executive vice president of business development. "Collaborating with customers on behalf of utilities is the primary role of Vertex. We manage the meter-to-cash processes of 70 utilities in North America, all of which will have some level of customer care impacted by the changes coming from the era of smart grid and demand response. It is our belief that to obtain full value from the investments in the communication infrastructure of the smart grid that fundamental change in business processes around interacting with customers is critical. The SGCC represents an opportunity for Vertex to help move that change agenda forward. By partnering with other member companies, consumer advocacy groups, utilities and regulators, the capacity now exists to ensure that the industry delivers the benefits of a smarter grid."

Circle **21** on Reader Service Card

INDUSTRY NEWS

Interpro Consulting Changes Name to UTILICASE

Well Respected Utilities IT Consultancy Gears up for Increased Focused on Its Software Solutions for Asset Management

Interpro Consulting announced on January 18 that it has officially changed its name to UTILICASE. The move marks a significant evolution of the company from a consulting and IT solutions provider to an end-to-end software and services firm. UTILICASE offers a full range of asset care optimization and investment planning solutions and services aimed at boosting efficiencies, improving reliability and performance, and reducing risk.

"Founded in 1994, Interpro Consulting has had a strong reputation for IT excellence in the electric utilities industry," said Marc-Andre Forget, President and CEO of UTILICASE. "We wanted to bring a more comprehensive end-to-end software solutions offering to the industry and we felt that the UTILICASE name was more indicative of this."

In addition to its consulting, IT, and system integration practices, UTILICASE has built software and services solutions aimed at asset care optimization and investment planning. The company's EPS-M solution was recently named a finalist in the prestigious IET Award for Asset Management.

On January 18, UTILICASE currently has more than 40 utility clients across North America who either currently utilize UTILICASE software or rely on UTILICASE Solutions for IT services and solutions.

Circle **22** on Reader Service Card

ComEd, Other Stakeholders Developing

Proposal to Modernize Illinois' Electric Grid Major utility infrastructure investment is essential for economic development, competitiveness and job growth

ComEd announced it is working with state policymakers, other Illinois utilities and interested stakeholders on a policy-based approach to modernizing Illinois' electric grid. As the digital age transforms the modern economy, the electric grid becomes all the more critical to economic strength. Immediate and sustainable planned investment in the grid is needed to keep Illinois competitive with other states.

The policy-based approach includes infrastructure investment programs, regulatory reform to support the investments, and measurable customer reliability benefits. If agreed upon by key stakeholders and approved by the General Assembly, this proposal would create the grid of the future, spur economic development, create thousands of new jobs, attract and retain Illinois-based businesses, and jumpstart Illinois' sluggish economy.

"Sweeping advancements in the way electricity is delivered and used are occurring across the country and it's critical to Illinois' economic competitiveness that we have an electric system to support the emerging economy," said Anne Pramaggiore, president and chief operating officer, ComEd. "System modernization will facilitate the growth and expansion of existing businesses within Illinois, attract new and out-of-state businesses and provide customers more control over their electric bills."

"This is the right time to decide the right way to modernize a major part of Illinois' infrastructure," said Kevin A. McCarthy, Illinois State Rep., 37th District. "Similar to how we facilitated the rapid technology boom in the telecom industry and brought countless advantages to customers, we can manage infrastructure investment and keep necessary consumer protections in place while unleashing the full resources needed to make Illinois an economic hub. This would be a win for everyone, and it is the kind of innovative public policy action our state needs right now."

"ComEd's proposal to ensure long-term investment in the electric grid would provide thousands of labor jobs for our members in communities throughout northern Illinois," said Dean Apple, president, I.B.E.W., Local 15. "Many parts of the grid are aging and in need of replacement to ensure system reliability. This plan would include much-needed programmatic upgrade work and minimize the need for emergent repair work."

The proposal would require legislative action to establish an investment plan, a new process for setting electric rates and measurable customer benefits. The new regulatory process will more efficiently provide for significant infrastructure investment and modernization by Illinois utilities.

A formula rate, like that used by the Federal Energy Regulatory Commission (FERC) for transmission, would make cost recovery more timely and predictable without reducing state regulatory oversight. Under the formula rate process, a utility would file annual rate adjustments to reflect changes in capital investment and operating expenses in a manner consistent with the established standards. A comprehensive annual review, conducted by the Illinois Commerce Commission, would ensure that Illinois utilities are not over or under collecting so rates are more closely aligned with costs.

The current process for determining rates is unpredictable and inadequate to support the long-term and programmatic investments needed for a modern and reliable electric infrastructure in Illinois, ComEd said. States across the country are recognizing that their old regulatory models are not able to facilitate today's investment needs and are looking for ways to adjust their processes to attract capital and invest the funds essential for modernization.

"Uncertain reimbursement for costs is eroding utilities' ability to fund long-term projects," said Pramaggiore. "The policy proposal we are discussing with policymakers and stakeholders would enable us to invest in technology solutions that avoid outages, while keeping customers' rates comparable to other major metropolitan utilities."

Today's economy requires 24-hour nonstop communications and vast transfers of electronic data - all dependent on a reliable grid. In 2000, the one-hour outage that hit the Chicago Board of Trade resulted in $20 trillion in trades delayed. Now more than ever, uninterrupted electricity supply is a paramount concern for all businesses. Companies like Groupon, Amazon and eBay all are dependent on a well-functioning grid. According to the U.S. Census Bureau of the Department of Commerce, e-commerce transactions in 3Q 2010 increased at a rate of 14 percent to approximately $39 billion compared to same quarter 2009.

"Businesses' reliance on digital technologies cannot be underestimated," said Doug Whitley, president, Illinois Chamber of Commerce. "A state that can provide more reliable power at a reasonable cost has an obvious advantage when competing to bring in new businesses. It is always appropriate for every business to attempt to incorporate modern, efficient technologies and systems in order to meet the needs and expectations of their customers. When technologies improve, winning companies move rapidly to adapt."

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SENSUS

What is Your Vision for the Smart Grid?

Over the past year, I've traveled the globe to talk with customers about the smart grid. We covered communications technologies, distribution automation and smart meters. We had lively discussions about home area networks and the importance of customer relationships in building a smart grid for the future. And we tackled the topics of security, distributed generation, data management and more.

In the end, the single theme that emerged from our discourse is that no two companies define the smart grid in the same way. In fact, each utility has its own vision of what their smart grid will produce, enable, improve and even inspire. And that got us thinking.

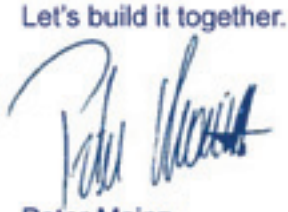
What can Sensus do to help customers realize their vision for the smart grid?

What we've discovered is that no matter how you define it, the underlying requirement will be flexible, open technologies that can accommodate every element and each phase of mission-critical smart grid applications that a utility can envision. That's why Sensus designed an expandable communications system based on open standards and a licensed, protected spectrum.

We believe that a truly intelligent grid is one that serves the unique needs of every utility. It's one that furthers the conservation of resources and makes the consumer an active participant in the energy ecosystem. And it's one that can support applications that a utility hasn't even thought of yet.

So no matter how our customers define the smart grid, we will continue to define Sensus as the company they can count on to help build their vision of the smart grid, now and well into the future.

Let's build it together.



Peter Mainz
Sensus CEO and President

Defining the Smart Grid.

Your vision, our technology...

Ask anyone to define the smart grid and you won't get the same answer twice. That's because no two utilities have the same requirements. Sensus lets you define the smart grid in your own terms. Our FlexNet™ system gives you a secure, utility-owned data highway for mission critical applications like smart metering, distribution automation, demand response and more, each communicating over its own dedicated channel. So you can build your smart grid of today with flexible, expandable technology to accommodate tomorrow's needs. No matter how you define it, the smart grid is only as smart as the people who build it. So let's build it together.

LET'S BUILD IT TOGETHER

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SENSUS

Leadership for a Clean Energy Future

S&C Electric, Chicago, Illinois USA

By John Estey, President & Chief Executive Officer and Michael Edmonds Global Smart Grid Strategies Director

Welcome to the first installment of *GreenWays*! Starting with this issue, *GreenWays* replaces the Automation/IT Leadership Series, which ran in this slot from 2007-2010. But I should point out that the change is not really so much a replacement as it is an update to the original concept established by its predecessor. That is, we have redefined the focus to place an appropriately increased emphasis on the future of clean energy as relates to the design, development and deployment of advanced electric power transmission and distribution automation. We will also expand the slate of companies providing insights for this column throughout the year to include not only those involved in supplying these exciting new technologies, methods and strategies but also users and others making contributions to A Clean Energy Future. We hope you enjoy this new feature, and as always, we welcome your feedback. – ***Ed***.

EET&D: This being the first installment of *GreenWays*, I guess you could say that you have the opportunity to set the tone as we go forward during 2011. Let's begin with some background on S&C for any of our readers that may not already be aware of the company's long history, and then we'll jump right into where you see things headed for the future.

Estey: Sure. S&C Electric Company is a global provider of equipment and services for electric power systems. Founded in 1911, the Chicago-based company designs and manufactures switching and protection products for electric power transmission and distribution. S&C's products help deliver electric power efficiently and reliably to customers across the United States and Canada and around the world.

Leadership for a Clean Energy Future

EET&D: What do you feel are the principal challenges facing the design/implementation progress of the Smart Grid?

Estey: I'm going to let Michael have the first shot at this because I know that he's quite passionate about what the future holds and the measures that we – as an industry – need to undertake to get there...

Edmonds: Thanks, John. Yes, I believe there are six primary challenges facing the progress of the smart grid. Let me start by giving you a quick synopsis of each, as I see them...

- **A "meter" frame of mind**: Despite the attention on smart meters, it's actually the "grid" that needs to remain reliable. While smart meters are great at gathering data, they can't increase capacity, optimize assets or improve service reliability. By focusing on distribution and automation, utilities stand to gain more smarts for the grid.

- **End customer burden**: The false starts we have seen over the past 18 months in the smart grid underscore the perils of relying too much on the consumer to understand, adopt and embrace new technology. While it's important that we bring the consumer into the conversation, it's important to recognize that reliability and quality of service can't be fixed with changes in consumer behavior or from smart meters. What we need now are some early wins to help demonstrate to consumers the benefits of smart grid technology such as improved reliability of service and customer choice.

- **Return on investment**: There is a lack of consistency on how utilities will recoup their smart grid investments. Public utility commissions, at times, add to this confusion when they do not approve inclusion of smart grid investments in a utility's base case, thus making investments unrecoverable in the existing rate structures. Smart grid investments could get stuck in pilot purgatory without a rational framework for utilities to recoup investments and get projects moving again. Utilities also need to carefully consider what their electric grids will require down the road to future-proof the investments they make today and ensure that these investments aren't wasted. Utilities need technologies today that can be cost-effectively upgraded in the future as new capabilities for the grid are developed.

- **Communications**: Today's grid communication abilities are limited – think of dial-up Internet before the introduction of broadband. For the smart grid to be truly automated and thus realize its full potential, we need communication systems that are capable of providing more than a meter reading every 15 minutes. Advanced grid applications—like fast service restoration in the event of an outage – require communication systems that can send much more data at much faster speeds.

- **Data silos**: Data integration is critical to the success of the smart grid. Data needs to be used on the local level for some functions but also needs to fulfill other functional systems used to run the utility (GIS, OMS, DMS, and so on). Without data integration, some smart grid benefits will not be realized. This data challenge also affects high-speed communications, critical to the flow of data transmissions on the grid.

- **Growing pains from renewable integration**: As renewable generation increases on the grid, control becomes a challenge as energy sources transition from central and 24X7 to decentralized and intermittent. The good news is that there is an increasing availability of new energy devices such as energy storage on the grid. Storage devices will improve reliability and increase utilization of grid assets, thus reducing carbon emissions because energy unused during low-demand periods will be made available during peak times. In order for a storage scenario to work, utilities need predictable rules regarding active network management and demand response to maintain grid stability. Embedding intelligence into the grid will also be essential to successfully integrating renewable energy resources. As increasing amounts of these generation sources will be distributed versus the centralized model of the past, distributed intelligence will ensure these resources are used most effectively.

EET&D: The Smart Grid involves making substantially all dimensions of Generation, Transmission & Distribution smarter. What are some key areas where an added level of intelligence and/or automation is needed?

Leadership for a Clean Energy Future

Edmonds: With the common focus on smart meters there has been a tendency to overlook the place we most need intelligence – in the grid itself. Service reliability and improved grid performance are directly tied to distributed intelligence in the grid, since this embedded intelligence allows the grid to deal with problems locally, where they are occurring, and supports response to problems in the proper timeframe. Investments in distributed intelligence will enable utilities to improve reliability and grid efficiency today, while also laying the foundation needed to meet energy demands as the grid evolves.

Future deployments of technology such as electric vehicles and distributed and renewable power will require local intelligence in the grid itself, along with the automation infrastructure that can take action in response to changes in system condition. For example, embedded intelligence will be essential to integrate energy storage within the distribution grid.

Automation will continue to enable more efficient uses for the distributed generation capacity that is increasingly being added to the grid and reduce the need to rely on fossil-fuel-fired generation. Volt-Var optimization applications will reduce the economic losses and carbon emissions associated with electricity losses from transmission and distribution. Utility assets will be used more efficiently when self-healing technology is deployed because less excess capacity will be needed to respond to outages, as utilities can restore power to as many businesses and consumers as possible while the damage that led to the outage is repaired.

It is true that if consumers change power consumption habits and collectively reduce peak demand, they will help reduce the need for new generation and infrastructure upgrades. However, consumers do not have the ability to improve service reliability or create additional grid capacity. In fact, proper application of energy storage, located at the substation or at the community level of the grid, can have the same or better effect as shifting consumer habits while providing greater control, predictability and reliability. Utilities can also use storage to shift system loading and generation patterns, which positively affects grid asset utilization, increases overall grid reliability and reduces emissions without the added investment required to change consumer behavior. While investments in distribution automation and energy storage seem to be smart investments for the intelligent grid, utilities need the proper mechanisms to allow recovery of the investments. In the end, without some type of return on their investment, many utilities will not invest in the smart grid, particularly once stimulus funds begin to dwindle.

EET&D: Any specific examples of how S&C is contributing to *Energy/Efficiency/Environment* issues?

Estey: S&C continues to provide innovative solutions that increase the efficiency and reliability of grid operations. For instance, the company played a lead role in several projects aimed at integrating stored energy into today's grid. Our Smart Grid Storage Management System provides the necessary technology to integrate NaS (Sodium-Sulfur) batteries into the grid. This provides a number of benefits, including deferring capital investments, improving service reliability and integrating renewable energy generation.

Energy storage also provides a green alternative for frequency regulation, as it reduces the need for spinning reserves from carbon-emitting, fossil fuel-fired generation. In addition to the Smart Grid SMS, we are developing community energy storage systems, which provide storage at the residential level to support a number of goals ranging from connection of electric vehicles to peak shifting. Community energy storage can be controlled in aggregate so utilities can bring stored energy online in the increments that are needed.

EET&D: What else do you see on the planning and development horizon for transforming the grid?

Edmonds: S&C continues to invest in R&D to advance self-healing solutions, and one area of focus is developing new smart switching technology. S&C invented pulseclosing, an innovative approach for responding to faults on distribution systems. Pulseclosing leverages distributed intelligence to significantly reduce the wear-and-tear on a utility's distribution assets compared to conventional protective approaches. Smart switches also use distributed intelligence to respond rapidly to system issues where they are occurring and thus provide improved reliability. They can simultaneously support smart grid applications such as volt/var optimization, which, in turn, delivers significant benefits in system efficiency.

Leadership for a Clean Energy Future

Estey: Also, this year we opened the Advanced Technology Center (ATC) at our Chicago headquarters to support smart grid research and development, one of our top priorities. The ATC is a high-power testing facility that allows us to test our products at home and thus, accelerate the development and delivery of critical solutions such as those related to renewable energy integration. This 43,000-square-foot facility is one of the most environmentally friendly facilities of its kind, and it's the first industrial building in Chicago to be Gold Certified by the Leadership in Energy and Environmental Design (LEED).

EET&D: Lately we've been seeing some indications that the economy is recovering, which is of course, good news for the country and for our industry. But what happens to transmission congestion when the economy recovers and steady annual demand growth returns as an issue?

Estey: Our industry has seen how difficult it is to site and build new transmission lines, and in some cases, these investments aren't a practical method for addressing demand growth due to the time it takes to build a new line. As such, the industry will look to smart grid technologies to maximize the amount of electricity demand that can be met with our existing transmission lines, and energy storage will be an important ingredient in the mix. It allows utilities to address capacity and reliability problems that might otherwise require the construction of new transmission lines. Use of energy storage for frequency regulation also reduces the need for spinning reserve from centralized generation plants, and thus reduces the need for transmission capacity to support such services.

EET&D: Any additional comments on that, Michael?

Edmonds: Yes. Integration of distributed energy resources and energy storage into the distribution system will further reduce the need for transmission capacity expansion. Smart grid solutions will enable integration of these resources. Distributed intelligence, for instance, will allow utilities to maximize the demand that can be met from distributed energy resources, while ensuring reliability of service to businesses and consumers by addressing problems on the grid locally, where they are occurring. Automation for Volt-Var optimization will also minimize the losses that occur through the transmission of electricity, effectively freeing additional capacity and further minimizing the burden of growing electricity demand on our transmission grid.

EET&D: John, as we close, how would you sum up the role of automation in making the Smart Grid a reality?

Estey: The future of a reliable smart grid is dependent upon automation. Automation helps the grid self-heal, efficiently use generation resources, avoid distribution losses and rapidly respond to changes, such as those related to storage and generation connected to the grid. The key is to build in the intelligence and communication bandwidth that will support both today's grid demands as well as demands that emerge down the road. If utilities adopt this strategy, they will extend the life of their investments, improve service reliability and lay the foundation needed to address the complexity of the future grid.

LightsOn

Remote Wind Energy SCADA Control System

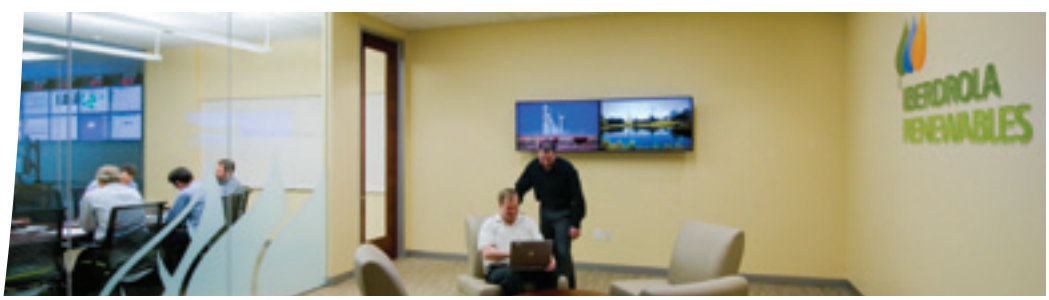
By Harm Toren,
Managing Director, Head of Operations Services
Iberdrola Renewables

Iberdrola Renewables provides wind energy globally, with their U.S. headquarters located in Portland, Oregon. Their operation is staffed 24/7/365 to manage their huge network of wind farms. It is vital for the organization to organize their energy distribution, scheduling, and dispatch to manage the green energy supply to their customers. They currently generate over 3,500 megawatts of wind power and other energy in 20 states with the goal of adding 1,000 megawatts each year – more than any other U.S. energy supplier.

Energy at the Speed of Wind

Wind energy is very abundant in many parts of the U.S. and does not need to be produced, so there will always be a constant supply. It is a form of solar energy that is pollution-free and renewable. This is likely the reason why wind energy is the fastest-growing source of energy worldwide. Additionally wind projects are entirely in line with President Obama's pledge to create millions of 'green' jobs. As the largest provider of wind energy in the world and the second-largest provider in North America, Iberdrola Renewables is playing a key role in supporting U.S. government's goal of achieving national energy independence.

At Iberdrola Renewables, our wind farms are professionally staffed 24/7/365 to provide energy management, scheduling, and generation dispatch capabilities. This helps our customers to manage risks and uncertainty in the natural gas and power industries while fulfilling energy requirements with sustainable and clean power. Originally called PPM Energy and part of Scottish Power, our company began operating in Oregon in 2001 with 12 employees. As of 2010, more than 850 workers throughout the United States maintain, develop, build and operate more than 3,500 megawatts of wind power and other energy facilities in 20 states with a goal of adding about 1,000 megawatts of new renewables each year – more than any other renewable energy supplier in the U.S.



Iberdrola Renewables manages over 3,500 megawatts of power from their offices in Portland, Oregon

Our latest operation in the Iberdrola Renwables fleet is the National Control Center, a nerve center in the wind industry located in Portland, Oregon. In a room that looks a little like Mission Control, our systems analysts oversee every turbine at every wind farm throughout the country, 24-7. They monitor the performance and efficiency of every turbine and keep an eye on approaching storms to warn technicians in the field to get to safety before harsh weather hits. They even help scientists conduct groundbreaking wildlife research at wind farms. And, they help the nation's various transmission system operators enhance grid reliability to help keep the lights on – no matter what the obstacles or challenges might be.

SCADA System

The SCADA system supplied by PcVue is a vital element of the control center. Each wind turbine has a control box containing a programmable logic controller (PLC), control boards, power converter, and I/O device at the top. Sensors for wind speed, shaft rotation speed, wind direction, etc. collect and transfer data to the PLC. By determining the wind's direction, the control system can use a motorized yaw gear to turn the entire wind turbine in the proper wind direction for maximum power generation.

All wind turbines are connected to a Local Area Network (LAN), with each wind tower's control box using Ethernet to link to the base of the tower where there is a fiber-based, redundant ring LAN connection. The LAN is connected to a remote control station running a control system that manages and collects data, adjusts turbine settings, and provides intelligent alarm, troubleshooting, and reporting capabilities via a central data center and control facility located in Portland, Oregon.

The SCADA connects individual turbines, substations, and meteorological stations to the central control room as well as operator visibility to supervise the wind farms as a whole. SCADA operators can determine corrective paths as needed from the record of activity they are seeing on a constant basis. It also records error signals, energy output, and availability and offers the capability to put in place any compliance requirements and control reactive power production, voltage, and power factors – allowing for the management of wind farms' contributions to network voltage and frequency control. It also allows operators the capability to manage power output based on real-time grid requirements.

Flexible Architecture

The SCADA system communicates with the turbines via a communications network that almost always uses optical fibers. Iberdrola Renewables uses multiple turbine types and each turbine supplier provides their own control/HMI system. A major advantage of the SCADA system is that it is turbine supplier agnostic and not tied to any particular PLC vendor, so that it can provide data reporting and analysis formats, irrespective of turbine type.

This was of particular importance to us because our wind farm operators use multiple turbine types and a wide variety of PLCs. Additionally, our team really liked the user-friendliness of the system we chose and the ease of configuration. Its ability to 'iconize' animated mimics and the use of pop-up windows also reduced the task of overlaying crucial information and helped simplify the view for our team.

Also, the creation of templates for contents and behavior associated with each mimic and GUI (graphical user interface) animation ensure consistency of the window display. We use multi-level access rights and menus associated with each user to ensure that navigation within the application is tailored to the needs and the permissions of each individual. This provides a layer of security, traceability and control of users' actions.

We have been in the global energy business since 2000. In the past – with a small number of wind turbines transmitting into the grid – it was a relatively easy data entry process. Currently, congestion has become a very big issue, with wind energy suppliers balancing energy production with available transmission injection points. Requirements are quite strict; thus, we have designed an integrated system with a curtailment of setpoints in order to manage the generation profile on a real-time basis. We are also working towards a more scalable system to meet the next generation of renewable energy transformation. And, we're installing wind turbines to operate in harmony with various forms of energy, including nuclear, solar, hydro, and other energy sources in a 'netting' arrangement to optimize performance – very much on the cutting edge.

In order to manage our growing business, we have developed fiber-optic networks on our wind farms in the U.S. along with a state-of-the-art National Control Center facility in Portland. A very similar system is also present at our facilities in Toledo, Spain (outside Madrid), called CORE (Renewable Energies Operation Center). In each case, there is a central facility whereby our SCADA system is able to remotely access facilities throughout the country and access alarm and event conditions.

The National Control Center SCADA system monitors wind generation across 20 states

Our management of multi-station configurations uses the SCADA system's advanced tools to ensure the coherence of the configuration data and deployment on all of the stations, especially for all of its geographically remote applications. Moreover, the centralized configuration provides the capabilities for the management and traceability of the various versions of applications and associated changes. It also supports automatic updating of the stations that make up the supervisory system. And, consistency checks of the versions in use are automatically run at each start-up of a station on the network.

Our Operation Center has a global potential to supply energy service to any interested owner, with no geographical limitations. In the U.S. we are currently producing 3,500 megawatts of wind power over 35 independent power plants. Iberdrola maintains 2,479 wind turbines. Each wind turbine supplies about 300 to 350 data points, which equates to approximately 700,000 to 850,000 I/O data points on nearly two dozen servers.

To cope with the diverse demands of maintaining our wind farms, the application alarms are highly configurable, permitting alarm messages to be printed, viewed in alarm lists and archived. Operators configure alarm behavior using groups, filters, sorting, acknowledgement and masking. They also create alarm counters and associate specific actions with an alarm. Alarms can be acknowledged by operators directly from mimics and automatically broadcast to all nodes on the network.

Iberdrola Renewables is using OPC (and others) as the communications protocol to pull data from the various PLCs. Many wind farm applications often use OPC (OPen Connectivity) and a special driver to seamlessly

communicate with disparate systems. We use the system's OPC Data Access Client and OPC DA XML Client for exchange of real-time data with communication servers, and OPC DA Server to facilitate data exchange with third-party applications. All of the data acquisition that occurs is routed back to the National Control Center.

I manage the teams developing integrated control systems. We chose PcVue's software for the Portland National Control Center, mainly because they had already proven to be user-friendly and highly functional in our Spanish operations.

The system proved reliable, scalable, and easy to configure, and CORE had been kept up and running quite successfully. A single user view that allows an easy visual display and overall management of the myriad systems in place from PLC, HMI and the control system equipped on the turbines is also a big plus. As we monitor avian migration and weather in addition to controlling and managing our turbines, we needed a system that would provide a simple, easy-to-read GUI so that we can react at a moment's notice.

The new SCADA software integrates and connects with the wind turbines via the GUI interface acting as a light client to the application and managing up to 2.5 million data elements. This configuration provides the operator all the necessary information about the turbine signals. We are utilizing this distributed client-server architecture with redundancy to ensure that the design is fault tolerant. Using these built-in redundancy features, we were able to ensure continuity of data collection in the event of a system component failure.

The system also supports dual networks, both for communication with field equipment and among PcVue stations. Each component and each station in the configuration has a validity status to enable operators to view the condition of the system in real time. These client stations are communicating via OPC with the redundant communication front-ends connected to the 1,000 Mbps TCP/IP Ethernet network. Each front-end is able to receive up to 60,000 I/Os.

Using this architecture, our operators can also see specific details of the remote wind farm data in a real-time display. Given the large volume of information – approximately 350 signals per turbine – and in order to facilitate operation and maintenance of the facilities, the supervision appears in two levels.

The first supervision level facilitates an overview of the most relevant alarms, values and counters – enough to supervise the turbines in a normal situation and detect failures that need to be corrected. A second, more detailed supervision level – triggered on an operator's request – enables the supervision of all the turbine's data selected so that operators can immediately diagnose, with accuracy, failures that occurred and determine the necessary corrective action. Received data can be processed as set points, historical storages, alarm management, trending, etc.

The control system in each installation collects the main operational information from the generators and their associated substations. The control system is connected to the Control Center through a remote communications channel, and therefore, facilitates maintenance tasks. The National Control Center receives this information and processes it into an organized and simplified structure that permits easy identification and diagnosis of failures.

This diagnosis triggers the appropriate actions for its solution: Remote reset or activation of local maintenance teams. As a result, average down time decreases, thus increasing availability while our operators can see in depth data from the remote wind farms.

Iberdrola Renewables in the U.S. completed the transitioning by the end of 2010, and so far, all expectations have been met and the system is working very well. This will become the standard process for all later facilities, so that it becomes their typical "out of the box" solution.

Harm Toren, Managing Director, Head of Operations Services for Iberdrola Renewables, is an energy industry professional based in Portland, Oregon. Harm started his energy career in 1976 with the U.S. Navy submarine service where he ultimately qualified as Nuclear Engineering Officer of the Watch. Entering civilian life in 1984, he worked in the utility energy sector at nuclear plants such as Quad Cities, Millstone, and Shoreham. Harm has started up and successfully operated two energy-based consulting companies along with working directly with utilities and independent power producers. Harm holds an MBA in Finance & Global Business Strategies from Utah State University.

The Reality of Renewables (Part 1): Why the Regulator-Developer-Investor Confluence Remains an Elusive Target

By Koustuv Ghoshal, Managing Partner
Inspirra Energy

As the dust settles in the aftermath of the financial sector collapse, and as the investment climate gradually shrugs off its state of hibernation, there is one aspect of the energy industry that has become crystal clear – the romanticism around the Renewable Energy market and the notion that it would somehow magically cure the world of all its environmental evils – has given way to the ground realities of a more prudent approach toward the development of sustainable sources for power generation. And this is not just a U.S. phenomenon. Hard lessons from Spain and Germany, takeaways from best practices in Ontario (Canada) and the allure of potentially exploding power markets in China and India, are all helping to not only shape policy decisions, but also to reset the expectations of project developers and institutional investors involved in the economics of the entire Renewable Energy sector.

The Dawn of Ground Realities

There is no denying the fact that generation from renewable sources is real and will continue to evolve as an integral part of the evolving grid infrastructure – whether as distributed generation or otherwise. The benefits – from environmental impacts to demand-side management – are many. The key question is: Who pays for it?

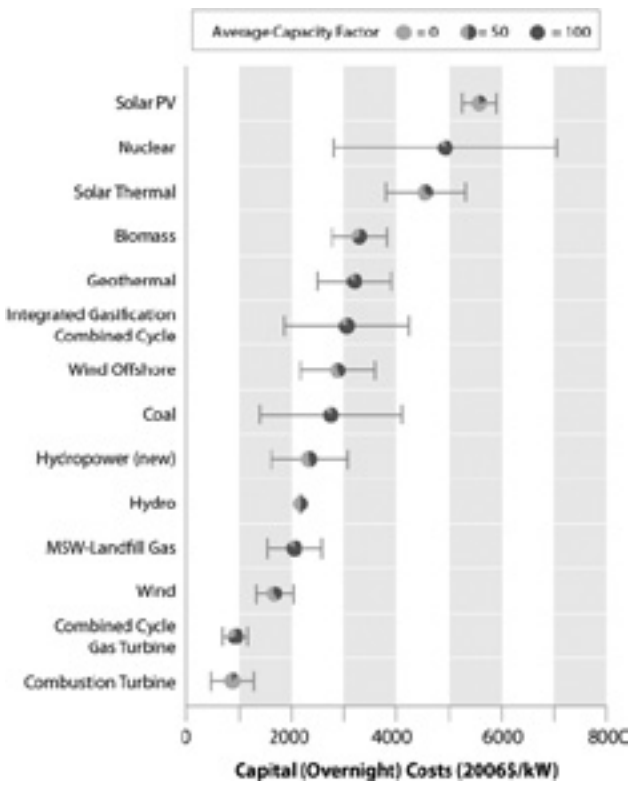


Figure 2: Plant Capacity Factors [SOURCE: NREL]

Dealing with intermittency

A simple fact has been established in every geography over the past few years that without some sort of government subsidy – whether in the form of grants, some type of feed-in-tariff (FiT) structure, buy-back guarantees, or Renewable Energy Credits (RECs) – it is difficult to economically justify a solar, wind, or other alternative energy source project, apart from traditional hydro and nuclear.

Given that the sun doesn't always shine, nor does the wind always blow when needed most, the one parameter that can make an enormous difference in competing with traditional forms of generation (e.g., coal, oil, gas, water, nuclear) is the availability of the feedstock, which impacts generation efficiency and/or plant load factor. Thus, external incentives – in the form of FiTs and RECs) – have to be brought to bear to compensate for the intermittency of the generation source. Moreover, it is imperative to improve plant capacity factors for some of the more popular forms of renewable sources, such as solar and wind.

Today, at large commercial deployments, some of the older wind projects are at about 23-27% efficiency. Newer, more efficient wind turbines have helped increase that to almost 35%. In the case of photovoltaic (PV) solar projects, the crystalline modules offer up an efficiency of as much as 17-19% from tier-1 suppliers, while some of the thin-film technologies are pushing the envelope at about 11-12%, resulting in plant capacity factors in the 20-22% range. Notably, a solar thermal array – without storage – can raise that capacity factor to an enviable 35%! A viable alternative – which is making a major resurgence – is biomass-based generation (via either combustion or gasification process) where plant capacity factors can be higher than 90%. However, the key that determines the economic viability of a biomass project is the long-term guarantee of the source and price of the feedstock.

So, what is different today? *Making renewable projects investor-grade...*

	Overnight Capital Cost ($/kW)			Nominal Capacity KW's[1]		Plant Costs	
	AEO 2011	AEO 2010	% Change	AEO 2011	AEO 2010	Fixed O&M (2010$/kW)	Variable O&M (2010$/kW)
Coal							
Dual Unit Advanced PC w/o CCS	$2,844	$2,271	25%	1,300,000	600,000	$29.67	$4.25
Dual Unit IGCC w/o CCS	$3,221	$2,624	23%	1,200,000	550,000	$48.90	$6.87
Single Unit IGCC CCS	$5,348	$3,857	39%	600,000	380,000	$69.30	$8.04
Natural Gas							
Conventional NGCC	$978	$1,005	-3%	540,000	250,000	$14.39	$3.43
Advanced NGCC	$1,003	$989	1%	400,000	400,000	$14.62	$3.11
Advanced NGCC with CCS	$2,060	$1,973	4%	340,000	400,000	$30.25	$6.45
Conventional CT	$974	$700	39%	85,000	160,000	$6.98	$14.70
Advanced CT	$665	$662	0%	210,000	230,000	$6.70	$9.87
Fuel Cells	$6,835	$5,595	22%	10,000	10,000	$350.00	$0.00
Nuclear							
Dual Unit Uranium	$5,339	$3,902	37%	2,236,000	1,350,000	$88.75	$2.04
Renewables							
Biomass	$3,860	$3,931	-2%	50,000	80,000	$100.50	$5.00
Geothermal - Binary	$4,141	$1,786	132%	50,000	50,000	$84.27	$9.64
MSW - Landfill Gas[2]	$8,232	$2,655	210%	50,000	30,000	$373.76	$8.33
Conventional Hydropower	$3,078	$2,340	32%	500,000	500,000	$13.44	$0.00
Wind Onshore	$2,438	$2,087	21%	100,000	50,000	$28.07	$0.00
Wind Offshore	$5,975	$4,021	49%	400,000	100,000	$53.33	$0.00
Solar Thermal (w/o storage)	$4,692	$5,242	-10%	100,000	100,000	$64.00	$0.00
Photovoltaic (crystalline)[3]	$4,755	$6,369	-25%	150,000	5,000	$16.70	$0.00

[1] Higher plant capacity reflects the assumption that plants would install multiple units per site and that savings could be gained by eliminating redundancies and combining services.

[2] Capital cost can be significantly reduced by structuring a Public Private Venture (e.g. with the incumbent municipality)

[3] Thin film projects can be carried out with ~40% less technology/module costs, however one has to keep in mind potential additional costs for increase in land/roof-top space and construction costs

Figure 1: Comparison of Capital/O&M costs of various sources of generation (SOURCE: EIA AEO 2010 Report)

Capital & Operational Efficiencies: To grasp what has changed one needs to first appreciate where the *Cleantech* sector was, as recently as eighteen months ago, globally. Did somebody say grid parity? Well, grid parity has been the utopia the alternative energy technology industry has been pushing hard. It is clear we're not there yet, but technology has improved to a point today – either in the form of concentrated PV, or higher efficiency tilt-rotor wind turbines, or even hydrogen turbine generation (HTG) technologies – that it has started to make economic sense from two points of view: 1) An initial per MW capital cost perspective, and 2) an improving LCoE (Levelized Cost of Energy); arguably the two key factors in determining financial viability of any power project.

Thus, a project developer has to pick its battle on what form of renewable project will make sense from an investor's perspective, taking into account not only the capital costs involved, but also how much of the regulatory hurdle a developer needs to cross, be it in terms of site control, permitting or PPA acquisition, before a project is deemed investor-ready.

Capability to Execute: Also gone are the heady days of pre-2008 when every owner of a hundred acres of land threw their hat in the ring as wind and solar developers. Today, investors and the regulators are looking for better credentials than merely land ownership. Just as it takes a village to raise a child, it takes a team of credible professionals to execute a power project. That means, a team experienced in:

Fund Raising: Without access to capital, all discussions are academic

Commercial Real Estate Management: With the increasing visibility of creating solar REITs (real estate investment trusts) for example, this is an important aspect of any renewable project development.

Power Project Development: Negotiating permits and power offtakes in the form of Power Purchase Agreements (PPAs) is more than half the battle!

Various Alternative Forms of Generation: This includes versatile, flexible strategies, such as optimization of commercially available technologies.

Engineering, Procurement & Construction (EPC): In the post development of a project this is the single most important team that can make or break any power project; and finally,

Operations & Maintenance (O&M):
It is clear that both institutional (e.g., private equity and hedge funds) and corporate investors continue to believe and back credible entities – a fact that has been exemplified in the recent past with the market valuations of SunEdison's (acquired by MEMC) and Recurrent Energy's (acquired by SHARP Solar) project development pipeline.

Some government involvement is a good thing… up to a point!

No one likes big government and even less, a government's involvement in a privately funded power project. This behavior is timeless… before and after any economic downturn. However, in times like this, when liquidity in the market is at a premium and when developers have scores of projects they are trying to get funded, one realizes the strategic value of a state's support. Till most renewable projects achieve the nirvana of "grid parity" we need to face up to the fact that without some help from the government, no renewable project will see the light of day for at least the next two to three years.

Policy Measures: Germany is probably the shining example of how to foster growth of environmentally sustainable forms of generation – particularly wind and solar – and yet not bankrupt itself in the process. Although Spain became the poster child of the solar industry with an industry leading FiT model, the oversubscription of its renewable portfolio mandate also ended up adding an enormous level of stress to its already strained coffers. And the province of Ontario (Canada) is currently experimenting with a high FiT structure to bolster growth of solar energy… lessons from Spain will also help keep economic viability in check.

China is on a tear. They are trying to not only supply their own needs for renewable power but is also fast becoming the major hub for supplying technology to the rest of the world. Countries such as India – which happens to have one of the best solar, wind and biomass potential in the world and, has the government transparency to boot – has leveraged "best practices" from both Europe and North America to craft legislation. As a result, an influx of major U.S. and European players to get a piece of the pie has already started.

State subsidies: The fact is, without the DOE-sponsored ARRA grant (Section 1603) in the U.S., most developers and investors would have shied away from promoting solar, wind and biomass projects over the past eighteen months. And the extension of the DOE grant for another 12 months (through end of 2011, as of now) will help sustain that growth pipeline.

The challenge in the United States is not so much the Federal/DOE oversight as it is the rather non-uniform fragmented approach being taken; that is, each state has its own policy. Some form of a FiT driven market has been established in a handful of states (California and Florida have taken the lead in that regard), while states such as New Jersey and Massachusetts (the most recent entrants) are trying to foster growth of solar via the Solar Renewable Energy Credit (SREC) market. Even with these state sponsored incentives, however, most private investors are wary of the sustainability of such measures. In order for the path to clear, there needs to be a line of sight to long-term SREC pricing structures to determine serviceability of a project's debt and equity needs.

In this author's opinion, such market-driven incentives should be a collaborative effort – the government defining the basic overarching policy that facilitates project development (versus growth-stifling rules and restrictions), while the market's supply and demand mechanism uses the policy framework to define rate and pricing structures.

Where it's still hurting: Although not necessarily at a grinding halt, the frenzy of wind development over the past five years has taken a hit due specific challenges that can be avoided with more support from regulators and collaboration with the investment community. An average cycle-time to close permitting and interconnection contracts now approaches almost two years in some cases… and that's for onshore projects! This kind of drawn out project schedule can cause the entire economic model for the project to turn on its head by the time it reaches the construction phase.

Moreover, it can take a grid-tied solar project (i.e., one that will be connected to the Transmission system) about nine months just to get interconnection clearance from an ISO… when an entire solar project can be constructed within six months! These timelines – which are uncertain at best – pose enormous strain on funds that are required by a developer to just "stay the course"… and most investors are not interested in funding small developers.

ABOUT THE AUTHOR

Koustuv Ghoshal is Managing Partner at Inspirra Energy, an independent investment banking and industry advisory firm focused on the mid-market renewable project development and energy efficiency sectors globally. Each of its principals has deep industry experience in energy industry market research, power project development, and project funding advisory. Koustuv can be reached by phone at +1-469-361-2120 or via email to *kghoshal@inspirra.com*.

Coming in the March 2011 issue of Electric Energy T&D… Part 2: How Can the Renewables Industry Sustain Growth? In the conclusion of this article, we'll explore some of the compromises that developers, regulators and investors may have to make in order to provide an environment for sustainable growth in the Renewables industry. Watch for it!

EPB Deploys America's Fastest Fiber-optic Smart Grid

By Lee Baker, Smart Grid Consultant

While many utilities struggle with the question of whether or not to build a Smart Grid, for the Electric Power Board (EPB) in Chattanooga, Tennessee, it was never an issue. The big question for Chattanooga's municipal utility was how to make its investment ensure far greater advantages than simply automating meter readings. EPB sought a solution that not only benefited the utility, but more importantly delivered ever-growing value to the community by improving quality of life and opening up economic opportunities. It took ten years for EPB to formulate its plans – and it took ten years for technology to catch up to its vision. But the city's decision to simultaneously deploy the country's most powerful fiber-optic network set a new standard for how a utility can lead the way toward a bright economic future while improving power quality, reliability, customer service and energy efficiency.

Chattanooga: The Smarter City

EPB is one of the first community-owned utilities to install a 100% fiber-optic network, which uses the fiber optic network for Smart Grid applications, in addition to the triple-play media services (i.e., high speed Internet, video and telephone) EPB already provides.

EPB technician deploys smart meter at customer home
Photos courtesy of EPB

David Wade, EPB's Executive Vice President and COO, says that "The broadband communications network will enable EPB's electric system to be intelligent, interactive, and self-healing – helping us to reduce customer outage minutes by 40%, provide our customers with the at-home tools and resources that will allow them to manage their energy use, increase power quality and much more."

Virtually unlimited bandwidth gives EPB lightning-fast, two-way communications with every device in its distribution system. While a network this robust is overkill for metering, EPB realized that fiber is essential for tightly coordinated load shedding activities, for the split second responsiveness required in distribution automation and, for a virtual real-time energy management tool for customers.

EPB BRIEF

- City of Chattanooga, TN
- 170,000 residential and business customers; 600 square mile service area
- Largest DOE ARRA stimulus grant recipient for municipal utility; $111.5 million to accelerate project; largest grant amount per capita.
- 1 Gigabit Internet offering to both residential and business customers; fastest in the U.S.
- Tennessee Valley Authority distributor

Chattanooga built the network to ensure a true Smart Grid as well as empower the community in new ways.

For instance, because bandwidth is no problem, EPB is able to offer its customers simultaneous Internet upload and download speeds of up to 1 gigabit – 200 times faster than the current national average and ten times faster than the FCC's National Broadband Plan (a decade ahead of schedule). This is just one example of how EPB's 100% fiber-optic network will provide countless benefits for the community in terms of education, healthcare, economic development, quality of life and more.

With virtually limitless data capacity, EPB's network will not become congested as millions of smart meters and smart appliances join the network and as data-intensive communications with these devices becomes more frequent.

EPB Operations Center – built to handle the massive amounts of data generated by the smart grid

Wade added: "The frequency of data transactions is increasing by orders of magnitude. Fiber-optic communications ensures that our network is prepared for anything the future has to offer. This way we can be certain that network efficiency will not diminish as traffic skyrockets. In addition to a high capacity, low latency backbone network, it's equally important that there are no congestion points on the local area network."

The network is designed so that data moves efficiently between the utility and every endpoint, regardless of whether or not a premise is connected directly to the fiber-optic network. This configuration ensures a smooth transition to implementing the energy efficiency initiatives proposed by the TVA (Tennessee Valley Authority) such as time-of-use pricing, load shedding, customer signaling and advanced distribution automation applications become more prevalent.

"Chattanooga is light years ahead when it comes to providing ultra fast broadband," said Tom Edd Wilson, President and CEO of the Chattanooga Area Chamber of Commerce. "By offering the fastest available speeds to a whole community comprising a diverse population living in both urban and rural areas, Chattanooga has become the living laboratory for today's innovations and tomorrow's companies."

EPB has built fiber optics throughout their entire customer service area and communications services are now available to all homes and businesses. By the end of 2012, all 170,000 homes and businesses will be equipped with a Tantalus smart meter. Although building the network is the first step, the Smart Grid, not TV, Internet and phone services, drove the business case. It was clear this technology was the key to increasing reliability and managing energy costs well into the future.

The U.S. Department of Energy (DOE) also saw the benefits and awarded EPB a $111.5 million stimulus grant so it could fast track the project.

Both the Smart Grid and communications benefits of a 100% fiber optic infrastructure is paying off by attracting new business, like Volkswagen's new North American manufacturing headquarters and an Amazon distribution plant.

Chattanooga will also be a test bed for Electric Vehicles (EV), with the Tantalus network providing the means through which 300 street-side charging stations will be monitored. During peak conditions, EPB can avoid overloading transformers by defer charging until the evening. On the other hand, the network can be used to measure how much power is being withdrawn from EV batteries if EPB needs to access energy stored in car batteries.

While discussion about the Smart Grid centers on how homeowners can better manage consumption and mitigate cost, EPB sees local industries as having the most to gain. Access to reliable, low cost power is essential.

"Everybody thinks about what smart metering means to residential customers," Harold DePriest, EPB's President & CEO, told MarketWatch last October. "But the real benefit of the Smart Grid will be the impact it has on businesses."

He added that EPB already has 22 large industries signed up for a time-of-use (TOU) rate program, and its projected that together they will save $2.3 million a year. Those kinds of savings help businesses run more efficiently and bring jobs to the community.

High bandwidth and low cost reliable power are two things that can make a community more attractive to industries looking to relocate. DePriest pointed to the savings that can be achieved just by reducing outages. "By installing intelligent switches, we can reduce outage duration by 40% on average," DePriest said. "Most of these savings can be accounted for because with the upgraded switching scheme, businesses don't suffer nearly the degree of productivity loss that would otherwise result from a prolonged power outage."

When time-of-use prices are in effect, manufacturers can reschedule or re-sequence operations to periods when energy is the cheapest. Furthermore, the ability to optimize power quality benefits the manufacturing process by minimizing the impact caused by minor fluctuations in voltage or frequency, which once disrupted highly sensitive manufacturing equipment.

Future Friendly Network

ADVANTAGES

- Network leverages EPB's fiber-optic investment for triple play media and enhanced Smart Grid functionality
- One of the first cities to implement municipally-owned 100% fiber-optic network; economic driver for the region and opportunity to improve energy efficiency

- Fiber-optic network supports simultaneous upload and download of up to 1 Gigabit
- Fast, low cost deployment of 1500 smart meters per week; self-configuring, self-healing network streamlines smart meter implementation and subsequent upgrades
- Helps industry become more efficient; TOU pricing expected to result in savings of $2.3 million a year for 22 manufacturers involved in time-of-use rate pilot
- Anticipates 40% in outage reductions resulting from improved distribution system management and intelligent switch technology
- Easy scalability; can support communications with the millions of data points expected to be on the network by 2012, including meters, demand response devices (i.e., smart thermostats & load control devices), distribution equipment and smart appliances

EPB doesn't expect to be in the pole position as the country's fastest broadband city for too much longer. Other communities across the country are in the process of building out Gigabit networks. But it's really a global race, with a handful of other cities around the world boasting lightning fast broadband service.

"What makes Chattanooga stand out is that it is leveraging the network both for a full range of Smart Grid applications and communications connectivity," Wade added.

"We looked at how the communication system and the electric system interact for many years and realized how closely tied together they are. As costs have stabilized and technology matured, we felt that the time was right to proceed with the project."

"We're building this network not just for today but for the future. The system we're building will provide rapid, two-way communications with every meter, home and device, making it possible and practical for our customers to interact with their energy use as never before."

He predicts that some customers will likely only want to know what their monthly usage is. For others – particularly businesses – it will change the way they use and value energy. Easy access to detailed energy profiles can help them determine whether everything is running efficiently and help them discover new ways to operate more cost effectively.

"Innovation is at the heart of everything we're doing here in Chattanooga," Wade continued. "We are driven to opening up new opportunities for people to manage their own energy use. Our 100% fiber-optic network will serve as a platform for accelerated innovation, job creation and deep creativity while serving as the backbone for the next generation of energy efficiency. All in all, with this infrastructure, we can't even imagine today what will be possible in the future – but we will be ready."

Fiber pull down in Chattanooga. EPB is building a lightning-fast, two-way fiber-optic network that will provide communications with every device in its distribution system.

ABOUT THE AUTHOR

Lee Baker is an industry consultant on Smart Grid systems with more than 39 years of utility experience, including 16 years as the general manager of a Tennessee municipal electric and water utility.

Portland General Electric (PGE) Solar Highway Project: Advanced Island Detection and Control

By Mark Osborn, Distributed Resources Manager, Portland General Electric
With Bill Flerchinger, Schweitzer Engineering Laboratories, Inc.

Portland General Electric (PGE) is a progressive utility in Portland, Oregon, and its efforts to increase the use of distributed generation (DG) throughout their system put them in a smart grid leadership position. PGE has developed an innovative distributed resources management system called GenOnSys that enables Distributed Generators to be remotely monitored and dispatched for renewable energy tracking, for peaking needs, and for providing operating reserves to the utility power system. PGE also has an aggressive goal: by 2025 it will supply 25 percent of its customers' electrical energy needs using renewable resources. PGE has already begun expanding their generation in the area of renewables with a 400 MW wind farm and distributed photovoltaic (PV) systems on their customer's property.

Connecting wind and solar generation into the existing power system has some unique challenges. Specifically, solar generation responds differently than traditional synchronous generators to changing electrical conditions. For instance, solar generation has a very high-speed response (e.g., low inertia) and large power ramp rates due to clouds blocking the sun's energy, then clouds passing, which, again, sharply ramps up the power. A joint effort between PGE; PV Powered, an Advanced Energy Company; Schweitzer Engineering Laboratories (SEL); and Northern Plains Power Technologies involves developing the next generation of smart inverter technology at two PGE locations: America's first Solar Highway Project and the Northwest's largest distributed solar project on ten warehouse rooftops owned by ProLogis.

The U.S. Department of Energy (DOE) sponsored the project to address new grid connection technologies that support integrating solar generated energy. The DOE Solar Energy Technologies Program (SETP) awarded PV Powered a third development grant to fund continued exploration of widespread adoption of solar energy on the grid. DOE's program, called the Solar Energy Grid Integration System (SEGIS), administered by Sandia Laboratories, focuses on commercialization of the technologies developed in the competitive program. The PV Powered team was awarded the grant after a successful phase 2 witness trial demonstration on the PGE electrical system this past summer.

The SEGIS program, specifically, focuses on making high-density solar generation possible. Using a system approach that utilizes advanced inverters, controllers, and energy management systems, PV Powered, working with PGE, is providing overall project leadership to:

- Improve inverter reliability
- Develop new algorithms to maximize the energy of the inverter and PV system
- Improve solar power forecasting and provide advanced system visibility
- Develop next-generation controls that allow utilities to manage networks of distributed generation
- Design advanced islanding detection and control systems

Better islanding detection and control are particularly pressing needs because the existing approaches for meeting IEEE 1547 requirements were developed based on the assumption that solar distributed generation represented only a small percentage of the total generation capacity. However, PGE has recognized that increasing concentrations of solar generation on power distribution feeders from the utility's Net Metering, large distributed solar, and feed-in-tariff programs will likely require new approaches to islanding detection and advanced communications with distributed solar inverter systems.

Today, solar generation inverters make autonomous-islanding decisions using local data, such as frequency and voltage, without understanding wide-area power conditions. These approaches make it very difficult for the inverter to distinguish between a local utility outage, which requires anti-islanding, and generalized power sag due to insufficient generation to match peaking loads. This could be aided by keeping the solar-based generators online, and transient disturbances where generators may be required under the Western Electricity Coordinating Council (WECC), to ride-through the disturbance.

The wide-area information available from time-synchronized phasors, or synchrophasors, provides the measurements needed to improve these methods. For large distributed generators, the standard protection method requires transfer-trip of a substation utility breaker communicated over fiber optics to a breaker at the solar installation. This is expensive, but effective in handling local distribution faults while riding through transmission events where the generation is still needed. However, current inverter technology disconnects the solar power during any power disturbance regardless of its location or cause.

Below is a summary of the SEGIS phase 2 work, done to design advanced islanding detection and control, and the results from the recent witness trial at PGE's Solar Highway located along the I-5 and I-205 highway corridor.

Islanding Control Methods

When a DG source is islanded from the bulk transmission system, the source must also disconnect from the islanded portion of the electric network. Failure to trip the source could risk personnel safety, power quality, and out-of-phase reclosing. The IEEE 1547 Standard for Interconnecting Distributed Resources With Electric Power Systems defines the requirements for integrating distributed sources into the bulk power grid with an aggregate capacity of 10 MVA or less. IEEE 1547 specifies that a source must disconnect from the islanded system within 2 seconds.

Existing Approaches for Islanding Detection

Commonly used techniques for detecting an islanded condition include perturb and observe approaches, power line carrier communications, and transfer trip schemes. Each of these techniques varies in cost; some are not commercially viable; some systems are very complex; and the power quality delivered to the customer may be unacceptable. Additionally, these techniques may work well with small penetration of PV, but have challenges to overcome in higher penetration scenarios.

The commonly used perturb and observe approach is cost-effective and simple to implement, but has the adverse effect of impacting power quality. The way the perturb and observe approach works is that the inverter actively pushes on a signal component, like frequency. When connected to the grid, this perturbation has little effect. When disconnected from the grid, however, the frequency changes according to the perturbation, and the inverter, upon detection of the excessive frequency change, declares an islanded condition. Issues with this approach include the negative impact it has on power quality. And, as the number of PV inverters increases, frequency shift coupling between them can lead to false islanding detection.

Power line carrier communications (PLCC) is more expensive to implement than the perturb and observe technique, but has no impact on power quality and can be used for high penetration PV installations. PLCC requires expensive equipment to be installed to facilitate sending a "heartbeat" signal across the distribution conductor to the distributed generation sites. This requires that a signal generator be placed in the substation on the secondary side of the feeder and that receivers be placed at each DG site. If the "heartbeat" signal is ever lost, the DG is immediately tripped off. The main disadvantage of this system is its high cost and that there can be interference from other power line carrier communications used. In addition, commercial availability of this approach has not been found by our research team.

Transfer trip is a commonly used technique for interconnecting large DG on a distribution feeder. A transfer trip scheme essentially monitors the status of all of the circuit breakers and reclosers that could island a DG site in a distribution system. When a fault produces a disconnection of the feeder from the substation, a central processor determines the islanded areas and sends a signal to trip the primary breaker associated with the DG system. This scheme is very effective and easy to implement for fixed topologies where the serving substation is located relatively close to the DG system. However, it can get complicated and very expensive if there are several scenarios of feeder reconfiguration or long feeder distances to the solar array.

Using a New Approach for Islanding Detection

Using synchrophasor technology for islanding control has advantages over the existing approaches. Synchrophasors improve these methods as wide-area information is available to each inverter. Using information obtained from a larger area results in better control decisions. Also, the communications paths are simplified because within the wide area only a few select signals need to be monitored. Finally, a system using synchrophasor measurements requires no unnatural forcing of the connected frequency, power, or voltages. Additionally, compressed communications protocols may reduce the need for high-speed communications, such as fiber optics, yet still achieve a fast indication of the islanded condition.

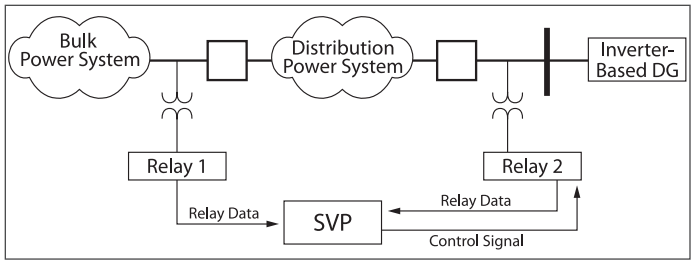


Figure 1: System Layout

System Configuration and Methodology Figure 1 shows the basic system layout. Both bulk power systems and DG locations supply synchrophasor data for the algorithm. The relays in **Figure 1** acquire frequency and voltage phasor measurements from their corresponding sites. Relay 1 and Relay 2 send synchrophasor messages at 60 messages per second to the control device, a synchrophasor vector processor (SVP). The SVP receives the synchrophasor data from the relays and calculates the difference between the local and remote synchrophasor measurements to determine if an islanded condition exists.

Figure 2

Figure 3

Figures 2 & 3: PGE Solar Highway site

Witness Evaluation at PGE Solar Highway Site

The islanding control algorithm was tested at PGE on a live feeder powering customer loads. The SEGIS team built a mobile resistive-inductive-capacitive (RLC) resonant load bank capable of islanding the inverter at full output power without disrupting these important loads. Relays that include phasor measurement unit (PMU) functionality were installed at the site location and the governing substation. This allowed the PMU data to be streamed from the substation to the inverter to determine if the PV system was connected to the feeder.

A SEL SVP was installed at the inverter location and performed all anti-islanding control algorithms. **Figure 4** shows the system layout. The substation utilized a PMU and a GPS clock. The inverter location also included a PMU and a GPS clock. An oscilloscope provided measurements for the live test. The mobile resonant load bank was a local load that was varied according to the test conditions.

The RLC load bank was tuned to 60 Hz at the representative available output power level of the PV system. During this time, the PV system and tuned RLC load bank were connected directly to the grid. To ensure the system was properly tuned, the grid-side currents were monitored and verified to be zero (real and reactive power from the substation were also zero).

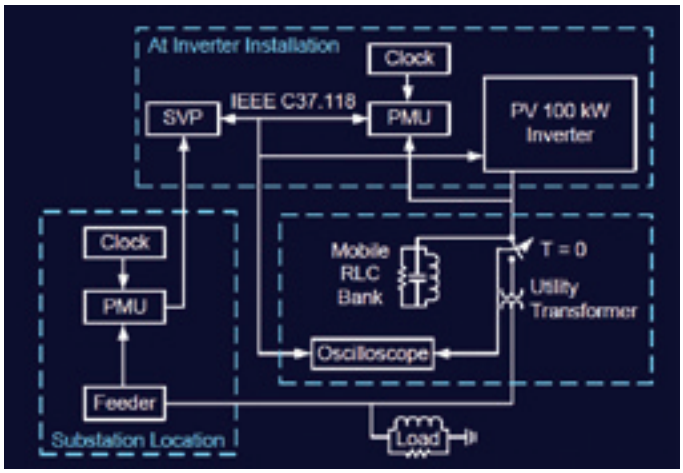


Figure 4: System Connection Diagram

The island was initiated with a contactor, which separated the grid from the PV DG system and RLC load bank, and the island formed. The islanding event was detected by setting the output relay on the local PMU device to write a logical 1 to an oscilloscope when the SVP determined that the slip or acceleration passed the thresholds developed for islanding. This allowed the team to capture the event. **Figure 5** shows the islanding event. The yellow trace shows the start of the islanding event. A change of state (in this case, a 5 V signal going to 0 V) occurred when the switch opened the contactor to the grid, and the island was initiated. The green trace is the output of the PMU and is controlled by the SVP to change state when the islanding event is detected. The time required to recognize and respond to the islanding event for this case was 1.12 seconds.

Figure 5: Results from Witness Evaluation Testing

Many islanding events were tested on the system using a quality factor of 1.0, as specified in IEEE 1547. To test the limits of the technique, island tests were performed with a quality factor of 3.0. For each islanded case, the synchrophasor-based technique determined that the distributed PV system was islanded in less than 2 seconds. The 2-second threshold is important because it represents current timing restraints set forth in IEEE 1547 governing safety functions for DG systems.

Tuning the system parameters has produced a much faster response in lab testing, and the team believes that with further refinement of the threshold settings, islanding event detection could be even faster than what was demonstrated at the PGE site. Communication compression or key algorithm reduction may also allow the system to exceed current IEEE 1547 thresholds with lower cost communications, reducing the need for fiber optics.

Synchrophasor measurements provide a viable approach to help solve the problem of highly concentrated PV-based DG islanding detection and control for distribution systems. Stage 3 work will incorporate more wide-area control algorithms into the controller. Future applications could include using the PV inverter to ride through low voltage conditions and other WECC requirements. Similar to the anti-islanding case, providing the PV inverter with time-aligned, wide-area information opens new opportunities to use this information for improved control algorithms. In the future, these improved algorithms will be one of the key innovations to permit safe use of PV systems on all homes and businesses.

ABOUT THE AUTHORS

Mark Osborn is the Distributed Resources Manager at Portland General Electric. As manager of PGE's distributed resources department, Mark Osborn oversees the utility's solar power development, dispatchable standby generation program (DSG), and the net metering and small generator interconnection programs. Osborn also leads PGE's efforts in the Pacific Northwest Smart Grid Demonstration Project in Salem, Oregon. Under Osborn's management, PGE has installed three major solar installations in Oregon including the nation's first solar highway project (104 kilowatt) and two of the Northwest's largest rooftop installations totaling 3.5 megawatts in northeast Portland. Osborn has more than 30 years energy experience and is an award-winning program manager and successful developer of new products and services for the utility industry.

Bill Flerchinger is a lead engineer in the Distributed Coherent Systems Department at Schweitzer Engineering Laboratories, Inc. (SEL). Prior to joining SEL he worked for Agilent Technologies, Mobile Broadband Division as the Product Planning Manager. He recently completed a Certificate in Transmission and Distribution from Gonzaga University. Bill received his Master's of Science in Engineering Management and a Bachelor's of Science in Electrical Engineering from Washington State University.

THE BIGGER PICTURE

VOL 3 NO. 1

BY GREGORY K. LAWRENCE,
PARTNER, MCDERMOTT WILL & EMERY LLP

2010: A Good Year for Demand Response

During the last several years, the market share of demand response (DR) resources in the organized wholesale electricity markets has nearly doubled – from 17,146 megawatts to over 31,000 megawatts since 2006.[1] In 2010, the Federal Energy Regulatory Commission (FERC) continued its efforts (in conjunction with ISOs/RTOs) to promote the continued integration of DR resources in the organized wholesale electricity markets. FERC's efforts are in part based on its statutory obligations to ensure competitive markets. Also driving these advances is a clear policy belief that DR resources are – and will continue to be – a vital component of a rational wholesale electricity market and the "greening" of the market.

In 2008 FERC took a significant step by issuing Order No. 719 to eliminate barriers to DR participation in the organized ISO/RTO markets.[2] Among other reforms, Order No. 719 required system operators to accept bids from qualified DR resources seeking to provide ancillary services and eliminated deviation charges during system emergencies for purchasers taking less energy in real-time than was purchased day-ahead.[3] Order No. 719 also permitted the aggregation and direct bidding of retail customers into the market unless otherwise prohibited by state or local law.[4]

Over the past year, FERC has taken several additional steps in support of increased DR participation in organized markets – including the issuance of its *National Action Plan on Demand Response* and the initiation of proceedings to examine how DR resources should be compensated for their services. FERC has also continued to demonstrate that it will monitor DR resources as vigilantly as it monitors conventional resources in terms of compliance with all FERC-approved market rules and regulations, including FERC's anti-manipulation regulations.

National Action Plan on Demand Response

Consistent with its obligations under The Energy Independence and Security Act of 2007 (EISA), FERC issued its *National Action Plan on Demand Response* (National Action Plan) on June 17, 2010.[5] Although the National Action plan is intended to be a plan for the entire country, FERC recognized that it will need to be implemented by states, localities and regions through coordinated effort. The National Action Plan is designed to achieve three main objectives: (1) assistance to states in the direction of developing and deploying DR resources, (2) a national communications program, and (3) the development or identification of analytical tools, information, model regulatory provisions, model contracts and other support materials for use by customers, states, and DR providers.[6]

In developing the plan, FERC solicited and received comments and participation from a vast number of diverse stakeholders. Before releasing the final plan, FERC issued a *Discussion Draft on Possible Elements for the National Action Plan*,[7] released a draft of the plan for public comment,[8] and held a web-based technical conference. FERC accepted written comments throughout this process, which came from industry stakeholders, governing officials, state regulatory utility commissioners, and nongovernmental groups including trade associations.

The National Action Plan calls for the formation of a coalition by public institutions and private sector organizations to achieve the objects outlined in the plan. The public-private coalition would coordinate the efforts of state and local officials, utilities and DR providers, regional market operators, consumers and the federal government. FERC staff is working together with the U.S. Department of Energy to develop an implementation proposal.

Notice of Proposed Rulemaking on Compensation for Demand Response

On March 18, 2010, FERC issued a *Notice of Proposed Rulemaking* (NOPR) aimed at ensuring adequate compensation for DR resources participating in organized wholesale electricity markets. FERC noted that DR helps improve the functioning and competitiveness of organized wholesale energy markets by lowering prices, limiting generator market power, and supporting system reliability, resource adequacy, and resource management challenges surrounding the unexpected loss of generation.[9]

[1] Fed. Energy Regulatory Comm'n, Comm'n Staff, National Action Plan on Demand Response 7 (2010) [hereinafter National Action Plan].
[2] Wholesale Competition in Regions with Organized Electric Markets, 18 C.F.R. § 35 (2008).
[3] *Id.*
[4] Id.; Wholesale Competition in Regions with Organized Electric Markets, 18 C.F.R. § 35 (2009).
[5] Energy Independence and Security Act of 2007, Pub. L. No. 110-140, § 529, 121 Stat. 1492, 1664 (2007) (to be codified at National Energy Conservation Policy Act, 42 U.S.C. §§ 8241, 8279).
[6] Id.
[7] Fed. Energy Regulatory Comm'n, Comm'n Staff, Possible Elements of A National Action Plan on Demand Response (2009).
[8] Fed. Energy Regulatory Comm'n, Comm'n Staff, Draft for Comment of the National Action Plan on Demand Response (2009).
[9] Demand Response Compensation in Organized Wholesale Energy Markets, 75 Fed. Reg. 15362 (proposed March 18, 2010) (to be codified in 18 C.F.R. pt. 35).

The NOPR focused considerable attention on the ability of retail and commercial customers to bid directly into organized wholesale energy markets. FERC also cited its concern that current compensation levels have negatively affected the deployment of DR resources in organized wholesale energy markets as a primary basis for issuing the NOPR. FERC's NOPR proposes to require RTOs/ISOs that allow for DR participation in their tariffs, to pay DR resources the locational marginal price (LMP), during all hours for demand reductions made in response to price signals.

FERC sought comments on several issues including: (1) whether a reduction in consumption is comparable to an increase in electricity production for purposes of balancing supply and demand; (2) whether DR providers and generators should receive comparable compensation; (3) whether paying LMP to DR resources is more or less than comparable to compensation paid to generation in RTO/ISO markets; (4) whether payment should apply to all hours, and if not, the criteria that should be applied for establishing the hours when LMP should apply; and (5) whether payment of LMP to DR resources should be required across all ISOs and RTOs.

On August 2, 2010 FERC issued a Supplemental NOPR in response to several issues raised by parties commenting on the initial NOPR. Specifically, the Supplement NOPR sought comments on: (1) whether FERC should adopt a net benefits test for determining when to compensate DR resources, what, if any, requirements should apply to the method for determining net benefits; and (2) what, if any, requirements should apply to how the costs of DR are allocated. Comments advocating the net benefits test focused ensuring DR resources only receive payments up until the point when the incremental payment for DR equals the incremental benefits of the reduction in load. Commenters also requested FERC address the issues of cost-allocation methods and demand response compensation simultaneously, arguing that the two issues are inextricably entwined.

FERC held a technical conference in September (2010) regarding the issues raised in both the NOPR and Supplemental NOPR. A significant number of comments were submitted in response to the conference, including those by market administrators that may be responsible for implementing changes following issuance of a final rule.

Enforcement Actions

In 2010 FERC also demonstrated its commitment to investigate and sanction market participants who FERC suspects of engaging in fraudulent activities within demand response markets. On October 28, 2010, FERC approved a settlement between its Enforcement Staff and North American Power Partners (NAPP) for violations of the anti-fraud rule in addition to violations of various PJM Interconnection, LLC (PJM) tariff provisions. NAPP agreed to pay a civil penalty of $500,000, disgorge profits of $2,258,127, and undertake compliance monitoring activities.[10] The NAPP settlement confirms FERC's belief that its anti-fraud regulation authority extends to resource agents operating in demand response programs administered by RTOs/ISOs.

According to Enforcement Staff, NAPP offered unavailable resources into a PJM market and failed to inform the resources of DR events. Additionally, FERC found NAPP overstated peak load contributions of its registered resources serving as demand response capacity in PJM. Finally, FERC found that NAPP registered 101 resources prior to obtaining the resource's authorization or verification of their willingness and ability to participate in the program in advance of the registration deadline for the 2008/09 planning season.

FERC also commenced an audit of a demand response aggregator participating in several markets to evaluate its compliance with applicable market rules and tariffs. FERC's Order No. 676-F is further confirmation of FERC's determination to maintain the integrity of DR programs by requiring each organized market to incorporate into its tariff the Measurement and Verification standard adopted by the North American Energy Standards Board (NAESB).

What to Watch For in 2011

Industry participants and market administrators are eagerly awaiting FERC's issuance of a final rule regarding how DR resources should be compensated. If FERC is successful in its stated goal of appropriately compensating DR resources, then deployment of these resources should increase significantly. However, many market participants are concerned that a one-size-fits-all approach with respect to implementation and cost allocation could result in unintended negative incentives.

Attention should also be paid to FERC's November 18, 2010, rulemaking to address the integration of variable energy resources (VERs).[11] FERC notes the importance of utilizing DR resources to provide grid flexibility as a means of integrating VERs into transmission grids. Comments to FERC's VER NOPR are due in early March 2011.

ABOUT THE AUTHOR

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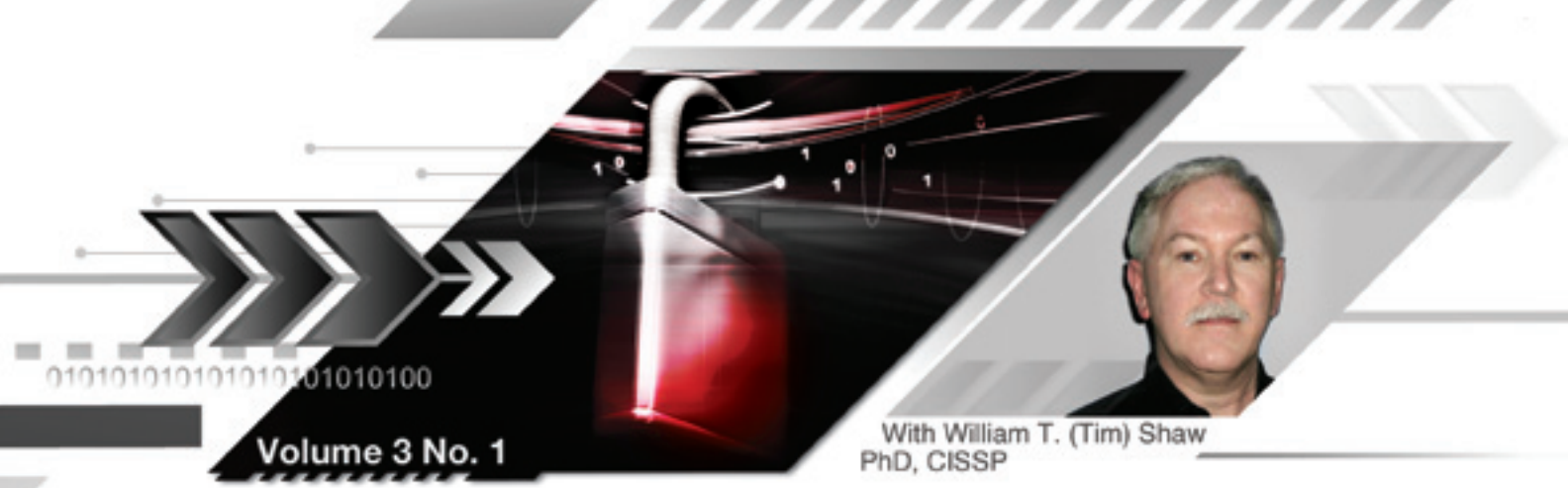
Additional Contributors

Terence Healey, Partner and Ben Chesson, Associate, each members of McDermott's energy group, provided significant contributions to this article.

[10] *North America Power Partners*, 133 FERC ¶ 61,089 (2010).

[11] Integration of Variable Energy Resources, 75 Fed. Reg. 17336 (issued November 18, 2010) (to be codified in 18 C.F.R. pt. 35).



SECURITY SESSIONS

All Quiet on the Cyber Front

Welcome to the first installment of Security Sessions for 2011! Well, another year has passed and for many (most?) of us it has been an uneventful year filled with the same old same old. Your days get to be somewhat stultifying when the same things happen (or don't) day after day after day. Of course, just when you are lulled into a sense of complacency, that's when the surprises occur. It would be great if they were mainly nice surprises, but they usually aren't. In the back of our minds we all know that undesirable surprises are going to bite us, and we all try to be ready for them. The same ought to be true when it comes to our security programs and cyber surprises. Are you ready? – ***Tim***.

If you're like me, it took losing a lot of important files, software and ongoing work to convince me to finally get into the habit of making regular backups of my various PCs. Oh sure, I knew intellectually that I ought to be doing that all along. But, like most folks, it took an actual computer hard-drive failure, and the resulting 'pain and suffering' to finally drive that point home on a visceral basis. That was several years ago, but now I make and retain disk backups fairly religiously. The pain has faded but the backup habit, engrained while the pain was fresh in my mind, lives on.

I try to share my learning experience about making regular backups with others. But, humans – being the imperfect and occasionally hardheaded creatures that we are – always seem to have to experience something personally in order to really get the picture. Cyber security preventative measures are kind of like that; people don't really believe they need them until the unthinkable happens to them personally. They may intellectually understand the arguments for protective measures, and the discussions of threat agents and malware, but it isn't REAL until it hits close to home.

One of the most frustrating aspects of security – particularly cyber security – is that if you have designed and implemented an effective and comprehensive security program you may never have a security incident. I'm not talking about the constant nibbling at the edges of your "electronic cyber-perimeter" that occur regularly if you have Internet connectivity. I mean an actual attempt to breach your electronic and/or physical security perimeter. If you present a strong enough security front to a potential attacker, after a bit of such nibbling and probing, the attacker may decide to look for an easier target. If not, then you are probably being targeted and you can likely expect to see a serious attack at some point in the future! The problem is that you don't usually know how many potential attackers were either scared off by your defenses or couldn't make any headway against them and gave up on their attempt to break in.

The fact is, it's difficult to keep people focused on security issues – let alone justify ongoing security expenditures – when nothing much ever seems to happen. The problem is similar to that of keeping folks focused on safety. People tend to remember safety and follow the proper procedures only after someone else didn't and was injured – or worse. Likewise, they usually start making regular disk backups right after they lose everything!

One of the reasons for an ongoing security awareness program, for periodic retraining of key personnel, and for periodic tests of your response and recovery procedures, is to help fight the effects of accumulated complacency. Another is to make sure that you are ready for those surprises mentioned earlier. By definition, surprises are unexpected, so you need to plan for them in advance. You need to design and prepare response and recovery plans and associated procedures that address a wide, but reasonable, range of possibilities.

Even more importantly, you need to practice these procedures periodically to make certain that your personnel can perform them and that the procedures are complete, accurate and actually achieve the intended results.

Over the years I've been extensively involved in reviewing response and recovery procedures. In performing tabletop rehearsals of such procedures, more often than not I find a point where an important step is left out, is incorrectly documented or requires something (e.g., a key, a password or a dongle) that may not be available to the personnel who would be performing the procedure. It is crucial to rehearse your critical procedures so that applicable personnel remain familiar with them and to identify and correct problems.

Often the problems with written procedures come from the fact that the people writing them are too familiar with and intimately knowledgeable about the process involved. Such people tend to leave out steps that seem obvious or intuitive to them. I like to hand important written procedures to people who have no knowledge about the process and purpose, just to see if they can follow along and perform the procedures successfully. I know that experienced and tech-savvy people get irritated with trouble-shooting procedures that start with: "Make sure the equipment is plugged in and turned on…" but the truth is that your critical procedures probably ought to go to that level of instruction and detail. The start of a new year is a good time to dust off those important procedures and organize a dress rehearsal to keep your staff on their toes and to identify any changes that may be required.

Even though nothing of a cyber security nature may have happened to you this past year, that lack of activity should not lull you into believing that your security program is perfect. People with NO security program or protections still manage to coast along without being subjected to an attack. But I think we would all agree that such a situation is mostly pure luck and that luck can easily be pushed too far, simply by continuing to rely on it as your primary defense mechanism.

Moreover, if you consider an absence of identified cyber attacks as the basis for declaring your program as 'perfect' you may be just coasting along and pushing your luck. The cyber 'threatscape' is ever-changing as new vulnerabilities are discovered and new attack mechanisms are being devised daily. In fact, nearly every year in recent memory has brought something new to the table. For example, discovery of the Stuxtnet worm this past year changed the rules again. And unless you routinely upgrade your defense profile, odds are that your current cyber defenses and procedures may not adequately defend against these new kinds of threats.

The start of a new year is a good time to review the latest cyber security threat information from authoritative sources –such as US-CERT – and then to reexamine your current security program with an eye towards ensuring that it is adequate to protect you from the latest and most potentially harmful threats. If it IS adequate, you have my congratulations! But if it isn't adequate (there are strong odds on that bet) then you had better evaluate, create and implement the necessary changes. Someone once said that whatever you did to reach this point won't be good enough to take you into the future. So as we embark down the path of a new year, that should be everyone's cyber security motto!

If you have implemented an intrusion detection system (IDS) or have the right advanced features in your electronic perimeter firewall(s) then you probably have logged events this past year that might indicate an attempt to penetrate your cyber defenses. But, analysis of event logs is still something of a black art, other than for after-the-fact forensic analysis. Skilled hackers know how to be very stealthy and what types of traffic characteristics an IDS or enterprise firewall look for to indicate likely attacks.

Thus, it isn't always easy or possible to sort the nibbling and probing log entries from the serious early stage of attack – i.e., hackers performing reconnaissance – log entries. But vendors of IDS and firewall technologies keep improving their detection capabilities, and vulnerability-testing tools (e.g., Metasploit and Nessus) keep adding to their capabilities.

The start of a new year is also a good time to check with all of your vendors for security updates and enhancements and to make sure your plant cyber security team or IT department is using the latest and best tools. It is also a good time to run tests on your defenses to verify that unauthorized 'holes' haven't been created since the last time you checked them and that they are still adequate against the newest attacks and threats. This is particularly true as regards wireless technology since most (all?) new computers come equipped with some type of wireless connectivity. It is always better that you find the potential problems and security vulnerabilities and fix them before the bad guys exploit them. Clearly, that's not the best way to find out you have problems!

Something I like to do at the end of every year is to review the list of new techno-toys to see if any of them pose a potential security threat. For example, this past year we have seen the introduction of new cell phones that can also act as a "hot spot" (WiFi access point) and also hand-held devices that provide the same capability. You might want to consider whether you need to update your policies and procedures to address such devices and how their use should be managed and controlled at your various facilities.

Maintaining adequate and effective cyber security is a never-ending project. I routinely prepare checklists of things I need to do monthly, quarterly and annually to test, validate and update my security program… but that will be the subject matter for a future column. Meanwhile, a happy (and secure) new year to you all! – ***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 *timshaw4@verizon.net*.

Riding the Next Wave of Smart Grid Automation New Approaches to Fault Detection, Isolation & Restoration

By Gary Ockwell, Chief Technology Officer
Efacec Advanced Control Systems

As the wave of AMI and smart meter deployments begins to crest, many utilities are poised to turn their attention to what is widely anticipated to be the next major focus area for Smart Grid projects – Distribution Automation. In particular, the automated isolation and restoration of distribution feeder faults is one application that can have significant impact on improving system reliability and quality of service, while laying the foundation for additional feeder optimization. After all, how valuable will the bevy of new intelligent power meters and home area networks be if the distribution system is unable to reliably and efficiently deliver quality power to the consumer? The good news is that there are now more options available when it comes to the implementation of automated feeder restoration systems – particularly solutions that use a model-driven scheme. This article will discuss some of the basics of this technology, and highlight some recent advancements that will give utilities more flexibility in its application.

Smart Grid App… Before Its Time

"Self-healing" feeder networks are typically implemented using two approaches - scripted (rules-based) and model-driven. The model-driven approach is often referred to by various acronyms, including FDIR (Fault Detection, Isolation and Restoration) and FLISR (Fault Location, Isolation and Service Restoration) This automated detection of feeder faults and reconfiguration to restore power to un-faulted sections is a Distribution Automation application that has now been around for many years. It can be argued that FDIR (the acronym we'll use for this discussion) is a true Smart Grid application that was somewhat ahead of its time.

While this level of unattended feeder reconfiguration was somewhat slow to gain traction in North America, some international utilities have embraced the technology early on with positive results. As early as 1998, the Taiwan Power Company implemented what is generally considered the first fully automated DA/DMS system, using FDIR on approximately 800 distribution feeders to cut typical service restoration times on un-faulted sections from 60 minutes down to only 20 seconds.

Increased Focus on Reliability & Performance

Since the late 1990s, utility performance regulations (reward/penalty structures) and increasing penetration of distributed energy resources and microgrids have increased pressure on utilities to respond efficiently to distribution faults and quickly restore power to as many customers as possible. The automated fault handling performed by FDIR provides many benefits to the utility and the customer that are well chronicled. These benefits include:

- Shorter outage durations
- Fewer sustained outages
- Improved performance indices
- Enhanced operational efficiencies
- Improved service quality

Feeder Automation Approaches Diverge; Goals Remain

Across North America, utilities have deployed many different solutions to achieve the fault isolation and restoration functionality. Some use distributed rules-based applications that rely on pre-determined topology and fault scenarios; others have more robust control-center configurations with a three-phase unbalanced load-flow model to enable additional feeder optimization functionality.

Ultimately, all restoration technologies share the same core objectives; that is, to:

- Accurately detect and locate feeder faults
- Isolate the faulted portion(s) of the feeder
- Restore power as quickly as possible (upstream and/or downstream of the faulted section).

FDIR is traditionally deployed as an advanced system-level application running on the distribution management system (DMS) in the control center. In recent years, some other methods of applying feeder restoration technology have entered the marketplace. There are still essentially two basic types of self-healing feeder architectures in use – distributed and centralized.

The distributed approach moves the automation intelligence out into the devices located along the feeders using scripted logic and peer-to-peer communication, while the centralized approach utilizes a control-center based algorithm and requires direct communication between the control center and the devices in the field.

The Distributed Approach

With the distributed approach, controller devices at the switch/breaker location contain the automation logic needed to restore a selected portion of the network. These devices communicate among themselves in a peer-to-peer fashion to determine where the fault has occurred and to determine the appropriate switching actions necessary for restoration.

Since the intelligence needed for restoration is localized and distributed among the controllers, this approach uses pre-programmed, or scripted, solutions based on a known baseline topology for that section of the network. Since no real-time network model is utilized, the system can have difficulty handling multiple faults and must usually be deactivated if the network is in an abnormal state (e.g., if any temporary switching has been performed). If the system is expanded, vendor services are usually needed to reprogram the restoration logic to include the additional feeders and devices.

The controllers in a distributed system are generally vendor-specific and often must interface with another automated control or feeder RTU at the switch, or may double as the switch control themselves. In either case, basic controller requirements for FDIR include the ability to detect feeder fault currents, detect voltage loss upstream of the switch, and store historical load data at the switch, which is then used to make downstream restoration switching decisions.

Some of the pros and cons of the decentralized approach are:

- **Pros**: Faster performance; quicker deployment; suitable for small "islands" of automation
- **Cons**: Requires more field maintenance/programming; specialized equipment needed; lack of real-time network model limits flexibility; unnecessary switch operations performed by opening up all switches before isolating the fault

The Centralized Approach

The centralized architecture is a model-driven solution and typically involves running FDIR as a subsystem of the distribution management system at the control center. Since the restoration intelligence is resident within the DMS, no specialized controllers are required at the substation or switch. This allows the utility to leverage automated controls that may already be in place. If these switch or recloser controls are capable of fault current detection, then no additional hardware may be required at all. If the fault detection capability is not provided by the switch control, then there are a number of low-cost RTU options available that can provide the needed telemetry.

Unlike the pre-programmed logic used in the distributed scheme, centralized FDIR utilizes a real-time load flow model of the network, meaning restoration actions can take place even if abnormal network conditions exist. It handles multiple-fault scenarios effectively. It makes possible more complex switching scenarios and load-transfer decisions such as a secondary load transfer to create additional capacity on the alternate feeder.

Using the model and the telemetered data, the FDIR application develops a switching sequence to restore as many de–energized feeder sections as possible using a minimum number of switching actions within the allowed overload and voltage drop limits of the impacted feeders and power sources. Another advantage of the centralized scheme is that FDIR can be configured to operate in a semi-automatic or automatic mode. In semi-automatic mode, the application creates the necessary restoration switching plan, but does not perform the actions until approved by the operator.

In 2003 Cobb EMC – located near Atlanta, Georgia – implemented a sensor-based location system using a private radio network to help speed up the location of faults on its more than 7,000 miles of line. Cobb, one of the largest member-owned cooperatives in the US, took that a step further in 2008 when centralized FDIR was added to the system to take full advantage of the more than 650 remotely controlled switches on its system.

> *"With a modern DMS in place and the investment we've made in automated sectionalizing capability, the centralized model-driven FDIR approach made the most sense for us," said Corbitt Clift, Manager of Special Projects for Cobb EMC. "We were able to add the application to our Efacec ACS Distribution Management System, utilizing our GIS as the network model source."*

Some of the pros and cons of the centralized approach include:

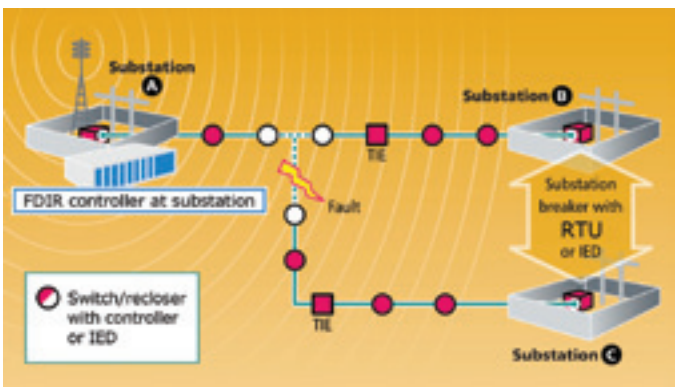
- **Pros**: model-based solution can effectively handle abnormal network conditions; can increase ROI through other feeder optimization applications (e.g., Integrated Volt/VAR Control); all data is available at the control center; no specialized field equipment required; no re-programming required for expansion

- **Cons**: requires controller communication directly with control center; larger implementations can be costlier; requires an accurate network load model before implementation

Today: A "Best of Both" Evolution?

While the two general schemes discussed here may remain the first-order choice for implementing feeder automation, there are evolutions of each of these basic architectures that can provide utilities with a combination of the advantages provided by both. A "semi-distributed" system is a model-driven scheme in which the FDIR algorithm is hosted at the substation level instead of at the control center. In this configuration, an intelligent substation controller serves as the field "host" for FDIR, utilizing a local network connectivity model updated with real-time topology for the area of automation. All feeder devices that are part of the automation scheme communicate back to the substation level only, and specialized field hardware is not required.

The FDIR controller at the substation can also act as a data concentrator, communicating back to a primary SCADA or DMS system for enhanced system visualization at the control center level. Expansion to multiple substations and feeders within the automation "island" is accomplished through the appropriate updates to the network model. The model can be updated offline when network updates or additions are made, and then downloaded to the controller remotely or loaded locally at the substation.

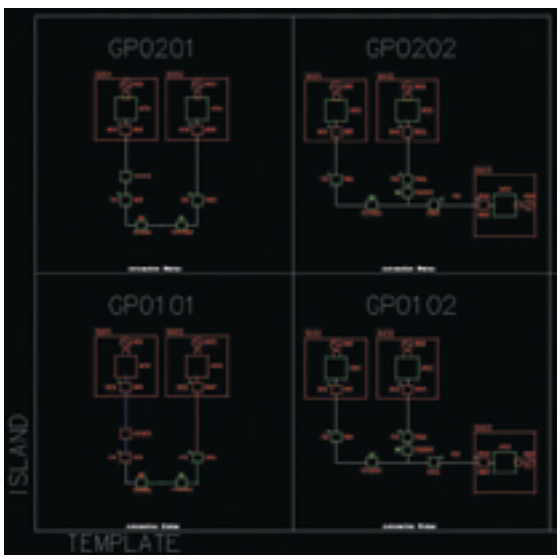


In a semi-distributed approach, an FDIR model is resident at one substation within the "island."

El Paso Electric (El Paso, TX) recently chose to implement a "semi-distributed" system to provide FDIR capability on a portion of the network in its Santa Teresa, NM service territory. "We were able to leverage the existing switch and controller hardware on the feeders, and felt that the model-based approach provided us with additional flexibility to handle different feeder configurations," said Roberto Favela, Superintendent – Distribution Systems for EE. "We expect this approach to integrate well with our other Smart Grid distribution applications going forward."

As an alternative to the traditional centralized architecture, utilities can also choose a separate centralized system that provides the benefits of the model-based approach to FDIR without the up-front cost and resources typically required to develop the network model. New ways to configure systems can simplify the process of creating this network model by using pre-defined network templates to create automation "islands."

The system provides the user a matrix of templates for differing numbers of substations, feeders and switches, allowing the utility to select the one that matches a particular island. A simple menu-based tool then helps define the specifics for each device in the chosen template (i.e., switch control, communications parameters, etc.).



A new centralized system can use pre-defined "island" templates to build a network model for FDIR quickly.

Using this approach, an automation island can be configured and operational in less time than it takes to program and implement a rules-based peer-to-peer system, at a comparable cost. This stand-alone type of centralized system links easily to a SCADA or DMS. It can expand to include other model-driven applications such as Loss Minimization and IVVC – providing further justification to the utility for the investment in an automation system.

This year, a major IOU in the south will pilot a system using this approach. Developed by Efacec ACS, the system will automate three independent templates with up to 15 devices in each – including switches, reclosers and breakers. Communicating with field devices using DNP/IP with IDEN modems, the system will provide FDIR functionality without operator intervention, using existing IED controllers already on the utility network.

Additional features will include:

- Substation dead-bus detection
- Interface to SCADA system
- Protection Function status monitoring
- 'Return-to-Normal' function
- Restoration status indicators
- Manual start for restoration after loss of voltage on transmission

FDIR: A Key Driver of Smart Grid Future Tech

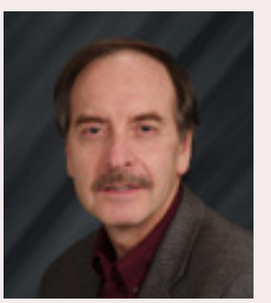
The wave of architecture options and technology choices has not yet crested. It continues to evolve as utilities today pursue the most effective feeder restoration solution to support their distribution automation systems. DA looks to be a Smart Grid trend that will see increased utility investment in the coming years. In an era in which demonstrable efficiency and customer satisfaction are increasingly important, FDIR is poised to play a vital role as a technology that delivers clear improvements in both.

The two traditional approaches to self-healing feeders have distinct pros and cons that must be carefully weighed when making planning and investment decisions. Yet with the newest innovations in model-driven FDIR system architectures, utilities are no longer limited to choosing between the two.

New combined approaches are bringing important advantages over either approach alone, depending on the unique aspects of each deployment. If each approach has formerly forced utilities to choose which wave to ride, the new technology is like two waves converging, offering users a powerful combination of tools to reach their goals. In fact, the future of FDIR may be an empowered utility in which users are likely to find that a mix of these architectures and systems allow them to define a hybrid approach that provides them with the best performance and value.

ABOUT THE AUTHOR

Gary Ockwell holds a BSEE Degree from University of Saskatchewan (Saskatoon, Saskatchewan, Canada). From 1973 to 1985, he worked for SaskPower Corporation in Canada, serving as the project manager for the Gas & Electric System Control Project and Manager of the Control Department. From 1985 to 1995, Ockwell worked for Harris Controls Division as a Product Manager. He joined Advanced Control Systems (now Efacec ACS) in 1995 where he now serves as chief technology officer. Ockwell is also a longstanding member of the IEEE Power & Energy Society.



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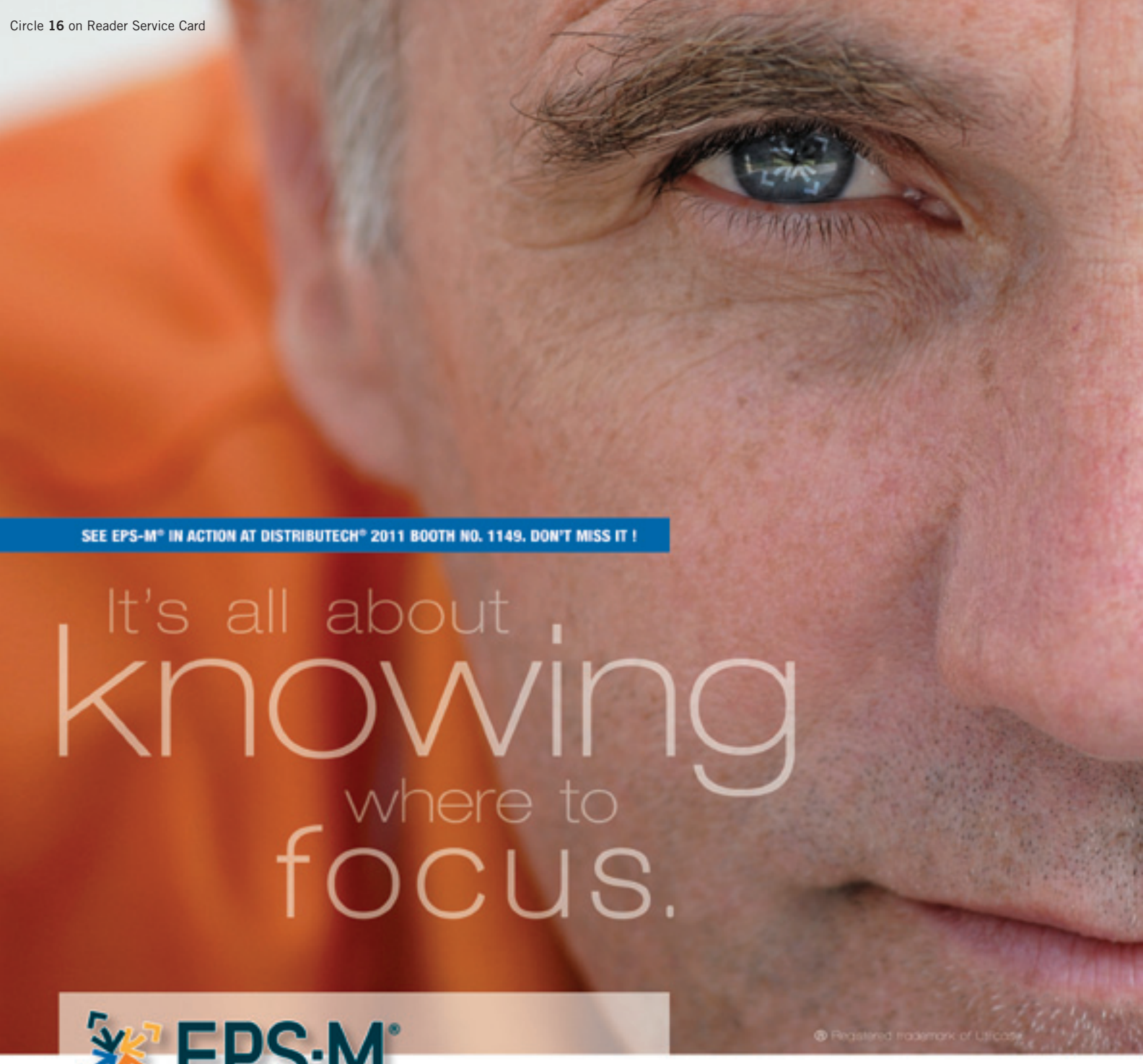

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