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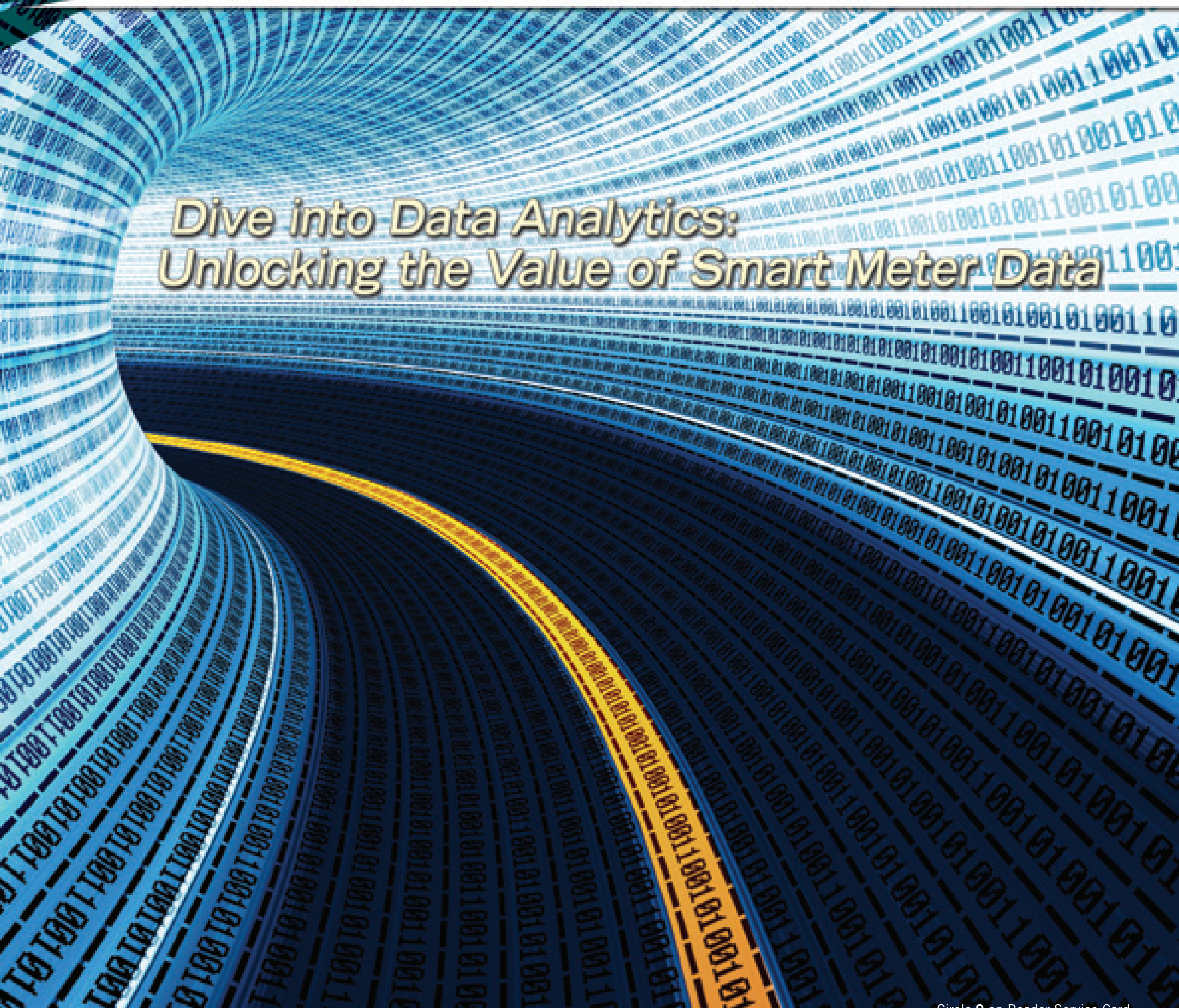

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Publisher:
Steven Desrochers:
steven@electricenergyonline.com

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

Contributing Editors:
William T. (Tim) Shaw, PhD, CISSP
tim@electricenergyonline.com
Gregory K. Lawrence, Partner;
Cadwalader, Wickersham & Taft LLP
greg.lawrence@cwt.com

Account Executives:
Eva Nemeth: eva@electricenergyonline.com
John Baker: john@electricenergyonline.com

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

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

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Web: www.electricenergyonline.com

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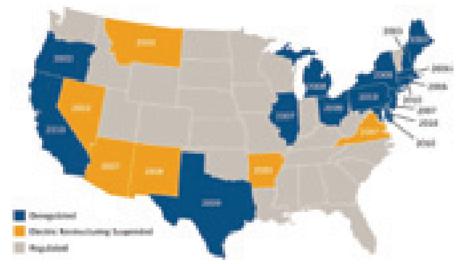

GridLines

Michael A. Marullo,
Editor in chief

Failure: Not all it's cracked up to be…

People just love to dwell on the negative – or at least it seems to be that way when it comes to new ideas, forward-thinking concepts and (especially) leading edge technologies. Lately I've noticed that our energy technology picture is being broadly painted with an escalating array of negative mindsets and getting more so practically every day… enough already! It's time that we step back, take a deep breath and rethink not only what constitutes success, but also to frame the role that failures rightfully play in that scenario.

Look, I understand that not everyone thinks like an entrepreneur, but I really think we've been giving the naysayers far too much airtime lately. Is it just me, or do the biggest news headlines always seem to have a negative slant? I'm not just talking about the national or world news here, although the broader media certainly fit all too well into that '*Negative news sells!*' mode. More specifically, I mean our own industry trade press, and the treatment we give to what should be a balanced (not necessarily equally, but not lopsided either), unbiased and factual treatment of the successes – and yes, the occasional failures.

One case in point is Solyndra, the failed solar panel manufacturer that was backed by a $550 million federal loan guarantee. One day, Solyndra was an example of a booming clean-tech startup, and the next (figuratively speaking, of course), it was the poster child for what has been portrayed as the failure of an entire industry – to which I say: Baloney!

Regardless of what position one might take as regards renewable energy technologies – and I have my own reservations about some of them – my gripe is not about the viability of the technologies themselves, but rather the prevailing notion that failure of any type, at any level, for any reason, is just that – total, complete and utter failure. Sorry, but I must beg to differ.

When it comes to business, failures are often the classic case of things not necessarily being what they appear to be. Businesses fail for a wide variety of reasons, some of which stem from implicitly bad products, poor planning, or other damning aspects of the business itself. However, when it comes to startups, many of them fail for reasons that are primarily circumstantial. Being undercapitalized, expanding into an economic downturn, losing a key team member or simply being unaware of the plethora of micro- and macro-economic factors challenging one's chances for success can stop even the best business ideas and product/service concepts in their tracks.

Key among these circumstantial factors is one that we often hear applied to both success and failure: *Timing is everything!* It's not just a cliché; it's true… timing IS everything when it comes to starting a new business – or in some cases, an entirely new industry. Above all, timing stands out as a principal reason why businesses succeed or fail, or why a new idea or concept catches on – or doesn't. If you think about it, you've probably seen many fundamentally good companies and novel ideas go down the tubes simply because they were too early or too late to market. It happens – a lot.

In another illustration that things aren't always as negative as they are initially portrayed, the Coalition for Affordable Solar Energy ("CASE") is battling SolarWorld's position that low-cost Chinese panels are violating international trade law.

GridLines

Michael A. Marullo,
Editor in chief

To make their point, CASE commissioned The Brattle Group[1] to conduct an independent analysis of the impact of the tariff on American jobs.

The study found that a 100 percent tariff scenario would indeed shut the lower-priced Chinese modules out of the U.S. market. It's also true that as a result, panel costs would subsequently rise. Yet, despite the initial outcry claiming huge job losses stemming from the tariff, look at what a follow up article said about net jobs in this excerpt from an article in the February 1, 2012 edition of *RenewableEnergyWorld.com…*

"According to the Solar Foundation, the U.S. solar industry grew to 100,000 jobs from August 2010 to August 2011. The Brattle Group report assumes a 24 percent growth to 124,000 solar jobs in 2012. What it doesn't include, according to report author Mark Berkman, is the projection that the U.S. solar industry will get to 140,000 jobs by 2014.

Digging a little deeper, the report's worst-case scenario envisions that the 50,000 lost jobs will include about half tied directly to the industry. These are your sales reps, installers, consultants and so on. The other 25,000 are very loosely tied to the industry and reflect the impact on reduced economic activity, aligned with things like groceries, clothing, financial services, real estate and health care.

What the report is really saying is that in a worst-case scenario, 25,000 solar industry jobs won't be created between now and 2014. Back that out from the 40,000 the report assumes will be created, and you end up with 15,000 new solar-industry jobs in the next three years. That projection is actually not far off the rate of growth we saw last year when U.S. solar jobs grew at a 6.8 percent clip.

Taken in context, these numbers are a far cry from the handwringing of 50,000 current solar industry workers getting a pink slip between now and then."[2]

Remember, this tariff was initially reported as a job-killer. Kudos to *RenewableEnergyWorld* for setting the record straight, but the fact is, countless good things are happening all around our industry every single day. In my view, those should be the topline stories of our time, and we should be reporting those stories in a proper yet balanced manner that emphasizes the positive side rather than dwelling on the negative and sensationalizing the relatively small percentage of inevitable failures. It's not that we shouldn't report the news good, bad or otherwise – we must. But despite playing an important role in the natural course of progress, failure certainly doesn't deserve the starring role. – ***Ed***.

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[1] *The Brattle Group provides consulting services and expert testimony in economics and finance to corporations, law firms, and public agencies worldwide. Areas of expertise include antitrust and competition, valuation and damages, utility regulatory policy and ratemaking, and regulation and planning in network industries.*

[2] *SOURCE: http://www.renewableenergyworld.com/rea/news/article/2012/02/solar-trade-dispute-behind-the-jobs-numbers?cmpid=WNL-Friday-February3-2012*

Iberdrola Renewables Announces 100-MW PPA with San Diego Gas & Electric Project creates more than 300 California construction and operations jobs

Portland, OR, February 2012 - Iberdrola Renewables announced a 20-year contract to sell 100 MW from its Manzana Wind Power Project, a wind farm currently under construction near Rosamond, Calif., in the wind-rich Tehachapi region, to San Diego Gas & Electric (SDG&E), a repeat customer.

"Iberdrola Renewables is delighted to continue our relationship with SDG&E," said Martin Mugica, executive vice president of Iberdrola Renewables. "This 100-MW power purchase agreement from our Manzana project now under construction in Kern County will strongly support SDG&E's efforts in meeting California renewable portfolio standard (RPS) requirements."

The project will provide up to 189 MW of energy, representing a reduction in green house gas emissions comparable to removing more than 21,500 cars off of California's roads for one year.

Ninety of the GE turbine "nacelles" used for the Project -- those Winnebago-sized components on top of the tower that house the generators, gearboxes, drive trains and brake assemblies – were manufactured less than an hour's drive from the Manzana site at GE's Tehachapi factory. The rest were manufactured in Florida. The turbine towers were delivered through the Port of San Diego.

About three-quarters of the turbines are already erected with construction of the operations and maintenance building as well as substation, collector system and transmission construction underway. Manzana is expected to create approximately 290 construction jobs, and 12 Iberdrola Renewables permanent operations and maintenance staff with approximately another 8 to 9 contractors during the warranty period.

The Manzana project will support the local economy with property tax payments expected to be in the millions of dollars over the life of the project. The property taxes will support schools, public health, fire, library and other necessary services in Kern County.

Construction is being managed by Avon, Minn.-based Blattner Energy, with the majority of subcontracted work performed by California companies including:

- Conco Pumping, Fontana – Concrete pumping
- System 3 Inc., Carmichael – Tower wiring & grounding
- RMR Equipment Rental, Castaic – Water trucks
- CSI Contractors Inc., Bakersfield – O&M building
- Soils Engineering, Bakersfield – Survey services
- Earth Systems, Palmdale – Inspection & materials testing
- PAR Electrical Contractors, Fontana – Gen-tie line and 220kV substation construction
- Rosendin Electric Inc., San Jose – 34.5kV Collector systems
- Granite Construction, Lancaster – Road improvements
- MCM Construction, North Highlands – Aqueduct bridges

More than 70 percent of the nacelles for the project turbines are being manufactured at General Electric manufacturing facilities in Tehachapi. Other California parts, materials and equipment providers include:

- General Electric, Carson – Down tower assemblies
- Bragg Crane Service, Mojave – Off-site storage crane service
- Pacific Coast Steel, San Bernardino – Rebar fabrication
- Holliday Readymix, Mojave – Concrete supply
- Granite Construction, Lancaster – Aggregate supply

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New Study Examines How States Evaluate Utility Energy Efficiency Programs Survey Finds Variety of Approaches, but Overall High Level of Engagement

Washington, D.C., February 2012 - As state policies requiring utilities to offer energy efficiency programs become more widespread and energy savings requirements become stronger, increasing attention is being focused on the issue of how these energy efficiency programs are being evaluated. One concern that has been raised is the apparent inconsistency in evaluation approaches across different states. Some have called for the creation of a "national standard" for energy efficiency program evaluation.

INDUSTRY NEWS INDUSTRY NEWS INDUSTRY NEWS

In response, the American Council for an Energy-Efficient Economy (ACEEE) conducted a comprehensive national survey, A National Survey of State Policies and Practices for the Evaluation of Ratepayer-Funded Energy Efficiency Programs (http://aceee.org/research-report/u122). The study found a great diversity in the policy framework, administrative structure, and technical details across states in their approach to evaluation; but overall, a high level of state regulator commitment to evaluation.

"These states take their responsibility for ratepayer protection very seriously," said Dr. Martin Kushler, ACEEE Senior Fellow and lead author of the report. "As someone who spent 10 years directing the evaluation unit of a major state utility regulatory commission, I can say that dollar-for-dollar, it's hard to think of any other aspect of utility operations that receives as much detailed scrutiny as energy efficiency."

Moreover, the variability in evaluation approaches across states does not seem to materially change the bottom line: energy efficiency programs are highly cost-effective. In a related earlier study, Saving Energy Cost-Effectively: A National Review of the Cost of Energy Saved Through Utility-Sector Energy Efficiency Programs (http://aceee.org/research-report/u092), ACEEE examined the reported evaluation results across 14 different states with major ratepayer-funded energy efficiency programs, and found that the overall utility cost of conserved energy across states-despite differences in evaluation approaches-only ranged from 1.6 to 3.3 cents per kWh. Any point in that range is far cheaper than any available new electric supply resource, which range in cost from roughly 6 to 14 cents per kWh.

The report provides the overall survey results on a wide array of variables, ranging from policy framework and administrative structure to cost-effectiveness tests, approaches for dealing with "free-riders" and "spillover," deemed savings databases, and a variety of key input assumptions. ACEEE did find some areas where evaluation practices could be improved and/or made more consistent, and those are noted in the report. An appendix to the report also provides links to individual state policies and rules regarding energy efficiency program evaluation.

GMP Enhances Merger Value for CVPS Customers Proposal Adds $40 Million in Efficiency Benefits to $144 Million in Guaranteed Savings

Colchester, VT., February 2012 - Green Mountain Power (GMP) proposed a $21 million investment that would provide approximately $40 million in energy efficiency benefits to Central Vermont Public Service (CVPS) customers. This proposal will enhance customer benefits from the proposed merger of GMP and CVPS, following CVPS's acquisition by Gaz Métro Limited Partnership.

"We believed our initial merger proposal, which contains $144 million in guaranteed customer savings over the first 10 years and millions more afterward, met the standard for PSB approval," GMP president and CEO Mary Powell said. "Having considered regulators' and stakeholders' views since we filed our proposal, and given our strong desire to provide significant, ongoing benefits to our customers, we proposed the creation of a new Community Energy and Efficiency Development Fund (CEED Fund) to help CVPS customers lower their energy bills and reduce their environmental footprints."

The CEED Fund addresses concerns raised by the Department of Public Service (DPS) and AARP stemming from a 2000 Public Service Board order. That year, the PSB approved an increase in electric rates to help the utilities cover the cost of electricity from a contract with Hydro-Quebec, but said that value should be returned to CVPS customers if the company were ever sold.

"This proposal is in addition to the $144 million in guaranteed customer savings," Powell said. "It represents a $21 million investment in energy efficiency on customers' behalf, which will bring around $40 million in customer benefits that can only happen with the merger of these two great companies."

Under the proposal, included in PSB testimony filed Wednesday and modeled after a program created when GMP was sold in 2007, the CEED Fund will invest in customer efficiency measures, community-based renewable energy, weatherization and other improvements that will create additional value and benefit for CVPS customers.

"This proposal demonstrates our continued commitment to the people of our state," Powell said. "Through extraordinary efforts to improve efficiencies both in our own company and in our customers' homes and businesses, we will significantly lower energy costs from what they would otherwise have been."

The CEED Fund would provide resources to lower the cost for CVPS customers to make energy efficiency improvements. According to a recent analysis produced by Optimal Energy for the DPS's 2011 Comprehensive Energy Plan, energy efficiency investments generate $5 in increased economic activity for every dollar spent, and create 43 job-years per $1 million invested. The economic boost comes not just from increased use of in-state resources to provide efficiency services, but in the subsequent spending and reinvestment of energy cost savings.

Besides the guaranteed savings and new efficiency proposal, the merger of GMP and CVPS will provide other substantial benefits for customers, including:

- annual $1 million for a low-income benefit program through VELCO dividend and contribution,
- enhanced storm response,
- integration of separate systems and services,

- an expanded commitment to community service programs established by CVPS,
- and a new Solar City Program and Energy Innovation Center in Rutland.

The new GMP will produce the $144 million in guaranteed savings without layoffs -- except for a handful of executives -- or forced relocation of employees. The company will be headquartered in Colchester, and the Operations Headquarters will be located in Rutland or Rutland Town.

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ComEd and Silver Spring Networks Expand Successful Smart Grid Program Energy Infrastructure Modernization is expected to deliver 2400 new jobs to Chicagoland and a range of customer benefits including increased reliability

Redwood City, CA, February 2012 - Silver Spring Networks, a leading smart grid networking platform and solutions provider, announced it has finalized agreements with Commonwealth Edison (ComEd), a unit of Chicago-based Exelon Corporation, to deploy its Smart Energy Platform to network nearly 4 million homes and businesses and Distribution Automation devices under the recently enacted Energy Infrastructure Modernization Act (EIMA), a key initiative for the state of Illinois.

ComEd's 10-year, $2.6 billion Infrastructure Investment Plan invests $1.3 billion to strengthen the electric system and another $1.3 billion to add new smart grid technology. Overall the modernization effort will create more than 2,000 full time equivalent jobs at peak in construction, engineering, IT, dispatching, equipment distribution and energy efficiency. Once the agreement is reviewed by the Illinois Commerce Commission (ICC), ComEd will begin installing smart meters.

Silver Spring Networks will open a new office in Chicago and establish a network operations center that will include dozens of new jobs in sales, marketing, network operations, project management and field engineering to support the build-out.

Previously Silver Spring and ComEd partnered on an Advanced Metering Infrastructure pilot program which demonstrated significant operational benefits for full-scale deployment including improved outage management. The pilot also demonstrated that providing customers with new pricing and information options using advanced technology can produce additional customer savings.

"We are honored to expand upon our successful partnership with ComEd in support of their vision and commitment to better serve their customers and prepare for the unique challenges of the 21st century," said Scott Lang, chairman, president and CEO of Silver Spring Networks. "We are delighted to bring new green jobs to the City of Chicago as well as the benefits of a modern grid – increased reliability, consumer choice and energy efficiency – to the state of Illinois."

The smart grid program will connect nearly 4 million homes and businesses over a 10-year period using Silver Spring's unified networking platform running multiple applications, including advanced metering and distribution automation. Silver Spring's secure and open networking platform demonstrates the benefits of the smart grid and uniquely delivers against the requirements of the groundbreaking Energy Information Modernization Act.

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TVA Study Shows Regional Energy Efficiency Potential

Knoxvo;;e. TN., February 2012 - The Tennessee Valley Authority's energy efficiency plans are within the achievable range of potential energy savings for the region, a study commissioned by TVA shows.

The study by Global Energy Partners said the Tennessee Valley could reduce energy use over five years by 2.2 percent to 5 percent by taking advantage of energy efficiency programs offered by TVA and local distributors, such as compact fluorescent lighting and heat pump heating and cooling systems.

Global Energy Partners, a California firm that has performed similar reviews for other utilities and government organizations, estimated the region's achievable savings potential at 3,256 to 7,494 gigawatt-hours by 2015. The high end of this range would roughly equal the amount of electricity produced by a large coal-fired power plant in a year; or the amount of electricity used annually by 500,000 Tennessee Valley homes.

The findings are consistent with TVA's Integrated Resource Plan, the agency's 20-year energy roadmap, and TVA's plans for Energy Efficiency and Demand Response programs. The IRP suggests TVA could achieve combined energy savings of 5.4 percent of TVA's sales by 2020. The five-year plan calls for combined annual energy efficiency and demand response savings of 2.9 percent by 2015.

"The study's results will help us refine and focus our path forward as we team with local power distributors to achieve TVA's vision to lead the Southeast in energy efficiency by 2020," said Bob Balzar, TVA vice president of Energy Efficiency and Demand Response. "Working with our distributor partners to reduce energy consumption and peak demand is a key part of our business strategy to keep rates low by avoiding the need to build more power plants."

The Global Energy Partners study says homes have the most energy savings potential, followed by businesses and industry. Energy efficient lighting and water heaters offer the greatest potential savings to residences. More efficient interior lighting, office equipment, ventilation and cooling delivers the most savings potential for the commercial sector.Industrial sector savings potential comes from energy efficiency improvements in machine drives and motors, fan and pump systems, and equipment upgrades.

The study also shows the region's potential savings from lowering peak power demand through TVA programs is more than 1,500 megawatts in 2012, and between about 3,900 megawatts and 4,600 megawatts in 2030.

Balzar said TVA is completing a full technical review of the study data and sharing study findings and assumptions with TVA's local utility partners.

"By highlighting challenges and opportunities in both planning and execution, we believe this study will ultimately help to inform future Energy Efficiency-Demand Response program planning, as well as TVA's IRP process for years to come," Balzar said.

Other recent TVA energy efficiency program achievements include:
In fiscal year 2011, TVA reduced peak power demand by 374 megawatts and electricity consumption by 559 gigawatt-hours, a one-year increase of 270 percent.

TVA's energy efficiency investment in 2012 ranks among the top five utilities in the country.

Two TVA states, Tennessee and Alabama, were recognized by the American Council for an Energy Efficient Economy's 2011 State Energy Efficiency Scorecard as among the nation's most improved states in energy efficiency. TVA has launched a new TVA EnergyRight Solutions suite of energy efficiency programs for homes, businesses and industries, with a new website at www.EnergyRight.com.

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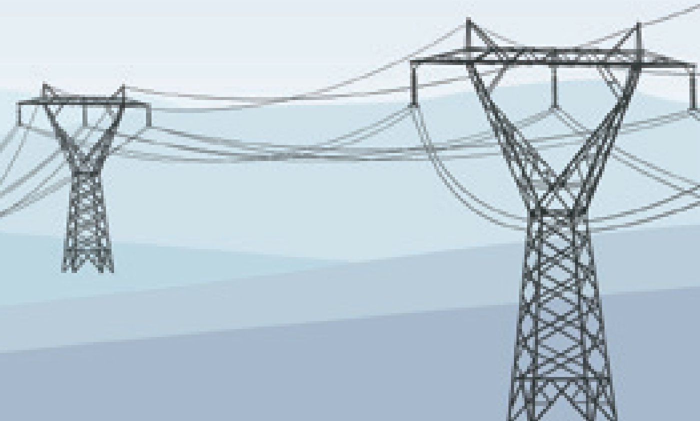


THE GRID TRANSFORMATION FORUM

Envisioning the 21st Century Grid

With Eric Murray, CEO, Tantalus Systems Inc. and
Mark deVere-White, SVP, Itron Energy Group
North America & Latin America

For more than two decades now, utilities have been installing one-way meter reading systems, resulting in literally millions of endpoints – often referred to as ERTs (Encoder Receiver Transmitters) – installed all across North America, Latin America and in other parts of the world. ERT technology is still being utilized by many utilities and has a long-useful life. Rather than throw these away and start all over, or wait until they are completely depreciated, two companies have come together to deliver two-way Smart Grid functionality allowing utilities to continue to utilize ERT technology now and in the future.

EET&D: If we look back over the past two decades, utilities waited a long time for the 'right' automatic meter reading solution, eventually investing extensively in (mostly) one-way, drive-by AMR systems. But lately it has become increasingly apparent that two-way comunications is quite likely to be a linchpin of the Smart Grid era. Understandably, a lot of utilities have no doubt been biting their nails over how to recoup future benefits from their earlier investments in the wake of this rapidly accelerating evolution to two-way communications as the cornerstone of AMI and other Smart Grid initiatives. But if I understand the Tantalus-Itron coalition correctly they now have reason to believe that their situation is not as bleak as it might have once appeared.

Murray: Yes, that's absolutely correct. Twenty years ago, no one could have reasonably anticipated all of the technological changes that have taken place, especially in the closely intertwined areas of metering and communications. It's really a whole new market landscape these days, and our desire to be part of the solution is at the heart of an exciting and still developing relationship with Itron that we feel will do just that.

EET&D: Can you share what precipitated this alliance?

Murray: First and foremost, we recognized that utilities need to intelligently scale their Smart Grid investments in such a way that operational goals could be met while creating a tangible return on their investments. That in itself established our primary objective of a joint offering that would more precisely serve their expectations of having access to economical, flexible, evolvable and powerful solutions.

EET&D: Mark, would you like to add anything to that?

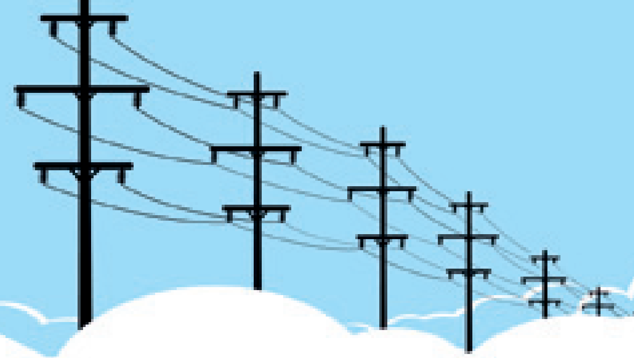
deVere-White: Yes, I'd like to say that through joint problem solving and coordinated system design, we focused on meeting utilities' business needs as much as their technical needs. Utilities need a way to ensure they are upgrading at the right pace but are doing so prudently and without needing to overhaul every single asset they own. So you could describe the Itron/Tantalus joint solution as a cost-effective asset management tool for utilities.

EET&D: You characterize this as an asset management tool. Perhaps you could elaborate a bit on what you mean by that, Mark…

deVere-White: Well, we recognized early on that our customers were making a strategic investment in their electric, water, and gas ERT technology and, that with the evolution from AMR to AMI, many utilities would have concerns that the useful life of the technology may be cut short. This partnership offers a solution to the challenge of migrating to a Smart Grid without cutting short the useful life of that technology. Now, any utility with an installed base of Itron devices can overlay a Tantalus Smart Grid communications network to improve the value of its installed devices and ultimately deliver AMI as well as demand response or distributed automation. This capability provides affected utilities with the ability to leverage their installed base of ERTs into a broader Smart Grid strategy that delivers advanced functionality.

Moreover, this offering benefits those cooperative and public utilities already using Itron's nearly 40 million electricity meters and 20 million gas and water meters by offering a simple way to upgrade to Smart Grid without waiting for assets to depreciate.

EET&D: Are there other ways that this solution can bring cost and/or resource savings to utilities?



deVere-White: Among other benefits, the joint solution delivers immediate value to the public power and cooperative utility marketplace and provides a solid foundation upon which a truly 'smart' grid can be built. And coupled with the ability to detect revenue losses in the field and deliver real cost savings, it also allows utilities to lower their operational costs through capabilities such as remotely connecting and disconnecting service to reduce the number of truck rolls.

EET&D: We also hear a lot about 'Big Data' these days. How can utilities leverage the data produced by these upgraded solutions and turn it into useful information?

deVere-White: Metering and communication endpoint technologies bring a wealth of data that can be utilized for power quality monitoring and analysis and active demand response programs. Engaging consumers in conservation programs with online data presentment and energy management devices, as well as providing dynamic rates, direct load control and EV smart charging are all part of what we bring to the table with this solution.

Murray: Let me add that in addition to the asset management dimension that Mark has already described, combination utilities, in particular, will benefit by virtue of the fact that this communications solution supports meter reading for electric, water, gas and propane ERTs. And since municipal utilities tend to have at least water and electric components, the ability to deploy an integrated solution is of special importance to them. The joint solution enables those utilities to move forward with water and electric initiatives knowing they will be able to bring them into a unified, common system. Also, with the increasing significance and scarcity of water, utilities that can get more leverage from their networks will be better positioned for meeting those challenges going forward.

EET&D: Which of these functionalities seem to be of the most interest to utilities so far?

Murray: Currently deployed metering technology is already quite robust, so we're seeing an emphasis not on acquiring specific metering applications but on leveraging currently deployed applications effectively. The fact is that very few utilities are interested in adopting everything. Instead, they are focused on specific operational benefits and a tailored approach to Smart Grid challenges.

For example, some utilities require surgical deployments, as in the case of specialized use areas such as industrial parks or corporate campuses. Others are interested in deploying pre-paid metering systems or remote connect-disconnect using their existing ERTs. Another application we offer that utilities are starting to utilize is CVR – or Conservation Voltage Reduction, which allows utilities to manage their power supply costs better. Overall, utilities want to minimize their infrastructure investment and deliver value to their customers. They also want the ability to select these advanced functionalities a la carte rather than in generic – and often pricey – full deployments.

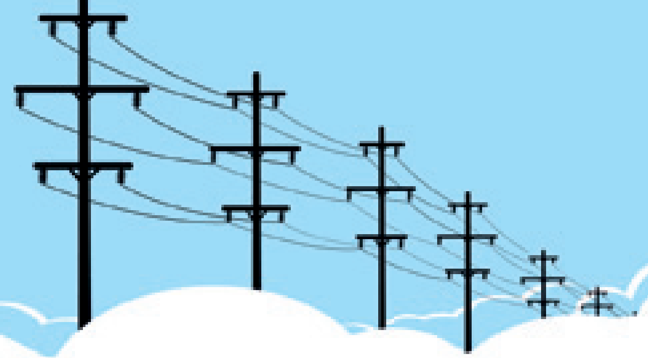
EET&D: Flexibility is another factor that most utilities say they want, especially when making substantial infrastructure investments like AMI. How does the joint solution address that need?

Murray: Flexibility is certainly another key area for which we are seeing a lot of demand. Utilities need a flexible on-ramp to the Smart Grid and value the ability to choose between multiple options or create a hybrid communications network of fiber and/or a wireless broadband network, based on their individual business priorities. This is especially important for utilities that are collaborating with telcos – an increasingly common phenomenon. For this reason, we prioritize evolvability and flexibility. Tantalus has already undertaken significant development efforts on developing Fiber-to-the-Home and multiple migratory WAN strategies. We believe that if you're making a 20- to 25-year investment, you need to be able to cost effectively evolve to a new network, if necessary.

deVere-White: The ability to incorporate ERT reading into the Tantalus network is another illustration of flexibility customers want and need to leverage those previous investments. By utilizing existing ERT readers, customers can deploy Demand Response and/or Load Control first, and start reaping the ROI from that before a broader deployment of smart metering. This allows them to do what makes sense, when it makes sense for their customers.

EET&D: What is the technological basis for the communications network offering?

Murray: The Tantalus network has a proven record of real-time, reliable command and control functionality in over 40 utility deployments and provides immediate two-way communication, allowing utilities to diagnose and correct problems faster and more accurately than any other solution. The platform utilizes fiber, 220MHz, 900MHz, WiFi, and cellular options. We are using the TUNet platform to build the integrated system for water, electric, and gas incorporating the ability to read existing ERTs, which will be available later this year. Notably, utilities will be able to phase in the integrated system over time if they choose and continue to make use of their existing metering software, which may already be integrated into other OMS, SCADA, or billing systems.



THE GRID TRANSFORMATION FORUM

Envisioning the 21st Century Grid

EET&D: How does this partnership fit in the broader scale of Smart Grid initiatives and help to move the industry forward?

deVere-White: For one thing, this partnership's international scope fits squarely within broader Smart Grid market trends. Reflecting the increasingly global demand for Smart Grid, we are focusing our joint efforts not only on the United States and Canada, but also on Mexico, Central America and the Caribbean. Overall, this partnership mirrors the industry evolution from AMR to pure AMI deployments to broader integrated Smart Grid deployments. Utilities are expanding their portfolios to include programs such as demand response or voltage regulation. I believe that by offering tailored solutions with the ability to leverage existing investments with minimal additional infrastructure investments, we are truly at the forefront of a trend toward more focused, more strategic, and more sustainable deployments of Smart Grid technologies.

EET&D: How does it appear that this relationship between Itron and Tantalus is being received by the industry so far?

Murray: Basically, we're offering utilities more choices and more options for their Smart Grid deployments, so since the announcement we've both been seeing a lot of customer discussions around their specific problems and how our joint team can help to resolve them. We're also working to optimize our behind-the-scenes processes in order to deliver value to our customers by working together seamlessly.

deVere-White: I agree with Eric and would characterize the response from the marketplace as overwhelmingly positive so far. Together, we are offering a highly innovative and flexible Smart Grid platform, designed specifically for public utilities and cooperatives. It's exciting for us to be able to provide an affordable path for electricity, water and gas utilities to effectively and economically transition and modernize their infrastructure.

GREEN OVATIONS

Innovations in Green Technologies

Energy Storage: A Work in Progress

By Tom Smolarek, President and
Treena Colby, Vice President, Cypress Limited

There is much interest and attention given to the potential benefits of energy storage. Research, private and government investment, and regulatory policy forums have been focused on a range of storage issues. Nevertheless, real-world market implementation will not go very far unless a focus on the customer value proposition moves to the forefront of the discussion. Ultimately an economic environment - including market, regulatory and utility rates and incentives - needs to be better defined for the customer to justify storage at their facilities.

First, the Basics…

Energy storage (ES) systems store energy for use at a later time, when electric power is most needed and most expensive, such as on hot summer afternoons. Energy storage can come in the form of chemical, mechanical and thermal means of storing energy.

Unlike other commodity products or energy resources, electric energy can't be easily stored directly as electric energy. The energy needs to be converted into a different form for storage. A battery, for example, uses a reversible electrochemical process. Pumped hydro uses gravitational potential differences. Thermal Energy Storage (TES) stores thermal energy, either cold or hot for later use. Delivering an electric energy benefit requires a second conversion process. Moreover, both the charging and discharging processes necessitate investment in the conversion technology, and both introduce inefficiencies, adding costs to the economics of storage systems. Thermal Energy Storage, for example, using chilled water or ice to reduce on peak electrical usage to off peak times has been a viable technology for over sixty years.

Growing higher price differences between on-peak and off-peak power, critical peak pricing strategies, targeted customer incentives and more renewable energy that is non-coincident with peak together can help various storage solutions to become much more economically feasible.

The Need for Storage

As you might expect, there is lots of research on energy supply and demand imbalances that will require alternative energy management, efficiency solutions, and some type of energy or thermal storage. For example, the North American Electric Reliability Corporation (NERC) reported that electricity demand in the United States is expected to increase by 135,000 MW in the next decade yet only 77,000 MW of new resources have been identified, creating a shortfall of 58,000 MW—an amount equivalent to 110 large power plants.

In theory, there would be minimal shortages of electricity and few distribution or transmission problems if it were possible to balance electric loads over a 24-hour day. In the real world however, there is a long list of contributors that disrupt balanced electric loads throughout a day and throughout the year.

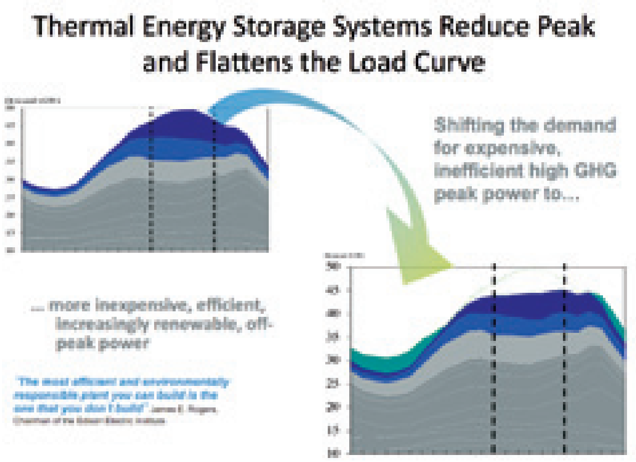
Storage is also is a valuable tool for integration of a high volume of renewable energy because the resource often is not available at times of high-energy use. For large-scale renewable generation such as wind farms, energy storage may play a pivotal role in reaching reliability standards and meeting frequency and ramping requirements.

The need for energy storage will continue to expand due to a convergence of several issues, including the rising cost to site conventional generation and delivery assets, increased load growth and lower load factors, and the need to address weak points in the distribution system.

The Benefits of Energy Storage – Utility

Energy storage applications that achieve the highest estimated revenues do so by aggregating several benefits across multiple categories. Capturing multiple benefits—including transmission and distribution (T&D) deferral and ancillary services - will be critical for high-value applications.

Reduced need for peak generation capacity: By storing energy generated during off-peak times and discharging it during peak times, storage provides an alternative to the construction and operation of new generation and reserve capacity. Peak demand growth is a major concern for many electricity planners, exacerbated by the fact that populations in the hotter parts of the United States are growing fastest. The value of the avoided cost of peak generation capacity will continue to increase as peak demand grows and as carbon emissions become more expensive.



"The most efficient and environmentally responsible plant you can build is the one that you don't build." – James E. Rogers, Chairman, President & CEO of Duke Energy

More efficient use of renewable and other off-peak generation: The development of wind energy has greatly expanded in the past few years, and more projects - including utility-scale wind farms – are being developed. Wind tends to blow most strongly at night, and for example, the California ISO predicts a serious mismatch of load and generation in the off-peak hours of 11 pm to 6 am, including as much as 3000 to 5000 MW of excess off-peak capacity. We have also seen some conflict between Bonneville Power Authority and wind energy producers in the Pacific Northwest due the BPA cutting off wind producers' high volumes of generation when it is not needed. Rather than forcing renewable generators to curtail production, ES can allow excess wind and store it for use at later times.

Transmission support and/or distribution congestion relief: Storage can be used to improve system performance by alleviating problems like voltage sag and unstable voltage. In addition, it can help to avoid congestion by discharging in congested areas at times of peak demand.

Increased and improved availability of ancillary services: Ancillary services are services necessary to support the transmission of energy from generation resources to consumers, while maintaining the reliable operation of the transmission system. There are two primary types of ancillary services, which could be provided by storage, which are:

Frequency regulation, which ensures that the grid operates within an allowable range of interconnection frequencies, and;

Operating reserves, which ensure that more energy can be added to the system within a short period of time to meet unexpected increases in demand or reductions in supply.

Benefits for the Customer

Customer storage tends to be an application-specific resource, and therefore, the costs – as well as the resultant benefits – can vary greatly. Consequently, considerable diligence needs to be undertaken for customers to provide the necessary economic and operational rationale for them to expend their valuable capital. There is a long list of potential customer operational benefits ranging from better power quality and back up to enhanced indoor comfort and avoided capital costs. However, the clear primary focus is on the economic value to the customer and the ROI that can be expected for installing a particular technology.

Avoided Utility Costs

In its simplest form, customer savings can come from shifting demand to off-peak times or simple DR peak reduction. Both assume that the utility is offering reasonable Time-of-Use rates or Demand Response offsets. Storage enables customers to change when they draw power from the grid to meet their demand. For customers on dynamic rates – that is, TOU or Critical Peak Pricing (CPP) – storage allows energy arbitrage opportunities, whereby the system charges when the cost of energy is low and discharges when the cost of energy is high.

The economic value of this load shifting varies depending on the individual customer's load shape and tariff, as well as the timing and frequency of when the load is shifted. Many commercial and industrial power customers have tariffs that consist of an energy charge, which is based on how many kilowatt-hours of energy have been used in a given time period, and a demand charge, which is based on the size of maximum demand within one month.

The installation of energy storage can result in cost effective reduction of energy charges if the spread between on-peak and off-peak time of use rates is large enough. Additional savings could come from reduced demand, provided that it reliably reduces the size of the customer's maximum demand peak. Additional potential savings are available for Demand Response events if the storage system can be controlled to meet DR requirements.

Benefits Summary

- Reduces on-peak electrical demand
- Reduces energy costs for the building owner

- Reduction in source energy fuel consumption due to increased efficiency of generation, transmission and distribution assets during off peak hours when operating to meet a steady base load
- Enables intermittent renewable generation sources to be system capacity resources by firming their intermittency and providing load when these resources are most abundant
- With good TOU and DR rates it will produce increasing customer cost avoidance
- For TES, separates the use of cooling from the creation of cooling – more efficient and less costly at night
- Moves load to night generation – better load factor, environmental GHG benefits, use of renewables

And, for TES systems…

- Can earn Green Building Council LEED points by reducing building energy costs
- First cost can be minimized – improves payback, reduce size of chiller plant
- Larger delta T reduces system flow (smaller pumps, pipe size)
- Lower temp air distribution means fan motor and duct size savings
- Smaller electrical service needs (switch gear, transformers, motor control panels, distribution)
- Addresses increased capacity issues due to inefficiency, increased internal building loads potential 50% + increase from TES
- With increasing outdoor air needs, RH control TES can better maintain temp at full load
- Adds cooling capacity to existing ducts, fans and pumps

Regulation and the Evolution of DR

The Energy Independence and Security Act of 2007 required the Federal Energy Regulatory Commission to perform a national assessment of DR potential and to develop a national DR action plan. In its "2010 Assessment of Demand Response and Advanced Metering" staff report, FERC gave demand response a slightly new definition, redefining it as: "Changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized." So far, adoption has been constrained in some states – and by some utilities – in part by existing state-level regulatory constructs.

California Takes the Lead

California has implemented several laws that have, in turn, shaped the storage marketplace. Reducing California air emissions to 1990 levels as mandated by the adopted Global Warming Solutions Act (AB 32) and reaching a targeted 33 percent Renewable Portfolio Standard (RPS) by 2020 present unprecedented challenges to utilities and their customers. The California legislature approved the Energy Storage Bill (AB 2514) in 2010, instituting a Public Utility Commission proceeding to establish a mandate for utilities to hold a percentage of their total generation capacity as dispatchable stored energy.

All forms of commercially ready energy storage technologies, including chemical, mechanical and thermal means of storing energy are eligible under AB 2514. While California has been involved in energy storage for past 10 years, AB 2514 places a much higher level of importance on energy storage.

California Utilities and Demand Response in the Real World

Southern California Edison and Pacific Gas and Electric have been designing, developing and deploying reliability and price-responsive demand response retail programs for more than 25 years. These programs include interruptible tariffs, direct load control, capacity-based retail products and dynamic dispatchable pricing.

For the last few years, SCE and PG&E have successfully used a program for peak load shift (PLS), using Thermal Energy Storage (TES). Thermal energy storage systems, which shift electricity for air conditioning and process cooling from on-peak to off-peak time periods, have proven to be one of the most cost-effective, reliable and feasible means to reduce critical on-peak demand and if applied properly can also achieve energy efficiency[1]. SDGE has also used this same program, but with a very different technology[2] to permanently reduce peak usage.

This Cypress-managed peak load shift program is based on a proven model of a first cost buy-down incentive on capital equipment, clear customer communications, and hands-on market channel support to promote participation and economic justification. TES installations will be customized to customer demand profiles, financial requirements and factors such as local distribution system constraints determined to be critical by the utility to ensure that the program meets the exact needs of the utility.

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[1] *Source energy reduction from 24-45%, Site energy 12-20% (non TDV, if TDV values can be higher depending on application, Emissions - source 30-50% from Source Energy and Environmental Impacts of Thermal Energy Storage, published by California Energy Commission.*

[2] *SDG&E used Gas Cooling to permanently reduce peak demand which is not a storage technology but still has solid benefits for both peak reduction and GHG reductions*

Part of the value proposition for the customer for such a program is that they can purchase a TES system that reduces their peak costs at a discounted first cost, while also generating lower overall cost of operations and total utility costs. Financial models and collateral materials were also developed to provide this information to the customer in an easy-to-understand, financial format.

One program participant owns and operates a 24-story, 430,000 square foot office building that uses less than 50% of the energy per square foot compared to similar buildings in the area after installing a TES system. Moreover, the two 800-ton chillers never come on during the 10-hour daily air conditioning cycle when the building is being cooled by the TES system, and only one of the chillers is neded at night to charge the thermal storage system.
The following table provides a perspective on the range of storage benefit categories coupled with the savings and potential economic value of energy storage. All values are presented from the utility avoided-cost perspective.

Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide

		Discharge Duration*		Capacity (Power: kW, MW)		Benefit ($/kW)**		Potential (MW, 10 Years)		Economy ($Million)†	
#	Benefit Type	Low	High	Low	High	Low	High	CA	U.S.	CA	U.S.
1	Electric Energy Time-shift	2	8	1 MW	500 MW	400	700	1,445	18,417	795	10,129
2	Electric Supply Capacity	4	6	1 MW	500 MW	359	710	1,445	18,417	772	9,838
3	Load Following	2	4	1 MW	500 MW	600	1,000	2,889	36,834	2,312	29,467
4	Area Regulation	15 min.	30 min.	1 MW	40 MW	785	2,010	80	1,012	112	1,415
5	Electric Supply Reserve Capacity	1	2	1 MW	500 MW	57	225	636	5,986	90	844
6	Voltage Support	15 min.	1	1 MW	10 MW	400		722	9,209	433	5,525
7	Transmission Support	2 sec.	5 sec.	10 MW	100 MW	192		1,084	13,813	208	2,646
8	Transmission Congestion Relief	3	6	1 MW	100 MW	31	141	2,889	36,834	248	3,168
9.1	T&D Upgrade Deferral 50th percentile††	3	6	250 kW	5 MW	481	687	386	4,986	226	2,912
9.2	T&D Upgrade Deferral 90th percentile††	3	6	250 kW	2 MW	759	1,079	77	997	71	916
10	Substation On-site Power	8	16	1.5 kW	5 kW	1,800	3,000	20	250	47	600
11	Time-of-use Energy Cost Management	4	6	1 kW	1 MW	1,226		5,038	64,228	6,177	78,743
12	Demand Charge Management	5	11	50 kW	10 MW	582		2,519	32,111	1,466	18,695
13	Electric Service Reliability	5 min.	1	0.2 kW	10 MW	359	978	722	9,209	483	6,154
14	Electric Service Power Quality	10 sec.	1 min.	0.2 kW	10 MW	359	978	722	9,209	483	6,154
15	Renewables Energy Time-shift	3	5	1 kW	500 MW	233	389	2,889	36,834	899	11,455
16	Renewables Capacity Firming	2	4	1 kW	500 MW	709	915	2,889	36,834	2,346	29,909
17.1	Wind Generation Grid Integration, Short Duration	10 sec.	15 min.	0.2 kW	500 MW	500	1,000	181	2,302	135	1,727
17.2	Wind Generation Grid Integration, Long Duration	1	6	0.2 kW	500 MW	100	782	1,445	18,417	637	8,122

*Hours unless indicated otherwise. min. = minutes. sec. = seconds.
**Lifecycle, 10 years, 2.5% escalation, 10.0% discount rate.
†Based on potential (MW, 10 years) times average of low and high benefit ($/kW).
†† Benefit for one year. However, storage could be used at more than one location at different times for similar benefits.

SOURCE: Sandia Report (SAND2010-0815); February 2010

Utility Cost Avoidance vs. Tangible Customer Value

Utility avoided costs are important, but in the end, it's the customer's value that needs to be articulated. Even though a given kW and kWH offset using storage can have a high value to the utility, until the utility actually agrees with the value and either builds it into a rate structure or creates a customer incentive, as far as the customer is concerned, the potential value is just that… *potential*.

Depending on the installed cost of storage on a per kW and kWH basis, the existing TOU rates and emerging Critical Peak Price rates – coupled with existing DR incentives alone or the planned Peak Load Shift incentives – will generally support reasonable customer ROIs.

For either residential or small commercial energy storage, if the installed cost per kW delivered can be in the $750-$2000 range for a storage solution with a duration of 1-2 hours or a full Peak Load Shift with a duration of 2-6 hours (ideally 6 hours), then the end-use customer market opportunity is significant and immediate.

However, customers – even those equipped with advanced metering and enabling technology – have not readily adopted dynamic pricing and frequent dispatching of customer-approved load reductions. Overcoming these hurdles, will involve education and awareness, new ideas, additional program design, system improvements and enabling technologies to facilitate customer participation.

General Conclusions and Parting Thoughts

- There is no silver bullet solution for grid storage and several technology classes will be important. Thermal Energy Storage is proven and is usually cost effective form the customer perspective if there are TOU rates and/or utility incentives.
- There is no well established unified market channel for energy storage technologies, except for TES
- Unless the customer can count on a good ROI, the true potential for storage at least on the customer side of the meter, will not happen.
- The market for grid-based storage for behind the meter installations for commercial and industrial facilities is growing and significant
- End-users of energy storage systems will try to aggregate as many value streams as possible to maximize the total economic benefit of their energy storage investments.
- The tariffs must pull and influence the usage of electricity.

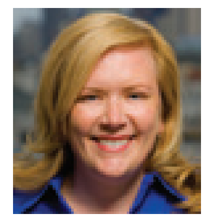
- For storage to be a customer investment, the rates must be reliable, and reasonably predictable
- One option for further analysis if to create special storage based tariffs charged for this commodity separate from any other influence except for what the commodity really costs

> "It should be noted that energy storage is not an end solution by itself. Instead it should be viewed as an emerging part of a new smart grid. This new smart grid will utilize many different technologies, including two-way communication devices, advanced metrology, and customer energy management software. Storage is just one of the technologies that will help improve the grid along with these other advances."[3]

About the Authors

Tom Smolarek founded Cypress, Ltd. in 1990, and he provides executive support and overall direction for the company. His role includes organization of all client projects and Cypress partners, strategic development of the business, expansion of capital and additional resource acquisition, as well as oversight of quality and commitment fulfillment processes. Under Tom's leadership, the business has successfully planned, launched and implemented various DSM programs and non-regulated energy services start-ups for a number of utilities and customer programs.

Prior to founding Cypress, Tom was Director and General Manager for Corporate Market Development for Square D Company (now Schneider Electric Company). Earlier in his career he held positions in General Management and Sales & Marketing Management at Honeywell, where he developed and managed both divisional and corporate sales development plans for its commercial energy business. Tom holds a BS-Pre-Med & Psychology and an MS in Psychology from the University of Wisconsin.



Treena Colby serves as Vice President of Business Operations for Cypress, Ltd., where she is responsible for analyzing the developments within the energy and utility sectors; identifying and securing new opportunities; and overall Cypress marketing strategy. She brings a unique combination of research, writing, marketing, event/project management skills, and deep knowledge of clean technology clusters.

Treena graduated from The Colorado College with a B.A. in Environmental Policy. She holds Board positions for the Network for Business Innovation and Sustainability (NBIS) and the Alumni Association Board for Colorado College.

[3] *Moving Energy Storage from Concept to Reality: Southern California Edison's Approach to Evaluating Energy Storage; Primary Authors: Johannes Rittershausen & Mariko McDonagh*

Central Vermont Public Service Proves Smart Grid Can Equal Smart Savings

By Jeff Breslen, Director Application Development, Central Vermont Public Service, and Todd Kowalczyk, Manager, Project Management Office, Central Vermont Public Service

Central Vermont Public Service (CVPS) is an investor-owned utility serving over 159,000 customers in 163 communities—the largest in the state. The company also has a long tradition of innovative rates and customer programs, and CVPS SmartPower® is a clear example of Central Vermont Public Service's vision to provide exceptional customer service and become the best small utility in America. The CVPS SmartPower® program is the largest capital project in the utility's history and is being partially funded by a $31 million U.S. Department of Energy Smart Grid investment grant.

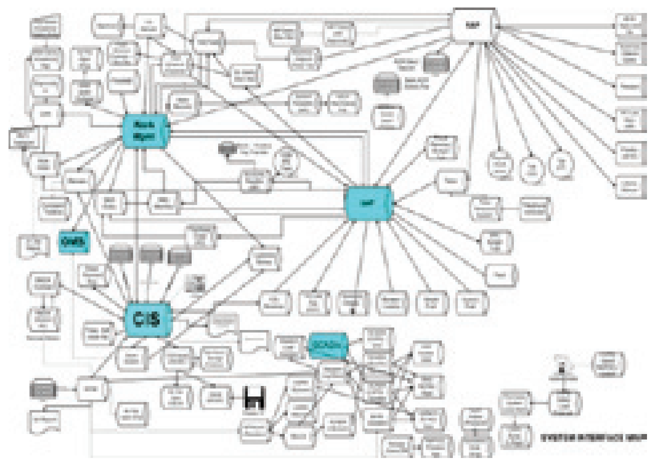
In early 2010, CVPS needed a way to quickly integrate its existing customer information system (CIS) and back-office systems with a new meter data management system (MDMS). The MDMS would serve as a key information and integration hub for CVPS's new Smart Grid systems. CVPS chose the eMeter Energy IP meter data management system (MDMS), implemented by Siemens, and is using this solution to power new efficiencies in a three-stage project that is helping to reduce costs and helping CVPS to abide by the terms of the Smart Grid investment grant.

As more utilities make the transition toward implementing Smart Grid solutions, it's critical to not only address immediate requirements but to also consider future business needs. Doing so requires considering three key factors during the planning phase of a Smart Grid implementation, especially when evaluating a new MDMS – scalability and integration, impact on business processes and its effect on your customers.

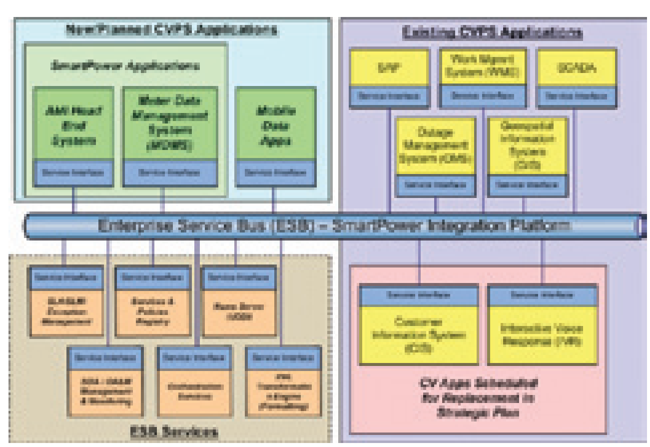
Scalability and Integration Capabilities

Every utility has unique needs, but regardless of size, scope or their service region, all utilities need to ensure that legacy hardware and software fully integrates with their new MDMS solution, and that the MDMS will integrate with future technologies.

The right meter data management platform will support capabilities such as remote service connect and disconnect, data analysis and reporting, outage management analysis and monitoring capabilities, and validation, editing, and estimation (VEE). Additionally, the MDMS solution needs to be flexible. The MDMS must be capable of being integrated into a service-oriented architecture (SOA) and also support any point to point integration requirements that a utility may have. With these characteristics in place, the MDM software can enhance utility business processes by extracting data from multiple sources and integrate this data back to existing back-office systems to ensure a rapid rollout.



Non-Service Oriented Architecture



Service Oriented Architecture

Compared to a non-service oriented architecture (left), the CVPS SmartPower project has a service oriented architecture (right) that allows for easy integration of additional applications and capabilities.

Having a flexible and scalable MDMS solution in place will allow utilities to support regulatory policies and increasing reporting requirements required by State and National governments. As more government mandates require rapid smart meter deployment, it's important to choose an MDMS solution that can easily accommodate growth and adapt as the Smart Grid evolves and new Smart Grid applications emerge.

The eMeter EnergyIP solution was chosen in part for its proven ability to scale with CVPS' Smart Grid plans. This includes the rapid deployment of approximately 180,000 smart meters during 2012 and other future service offerings the company has planned related to advanced outage management and distribution automation.

Improved Business Efficiencies

CVPS' Smart Grid implementation including the new meter data management system will yield an estimated annual savings of $2-5 million. Many of these savings stem from reductions in legacy business processes such as manually reading customer meters and the use of handheld meter reading devices, but also include decreases in the costs associated with truck rolls including fuel costs and vehicle repair charges. Even more, automated services made possible by the MDMS decrease the time employees would normally spend assessing the scope of an outage and identifying the level of utility response that is required, allowing personnel too much more quickly respond to outages or other grid issues.

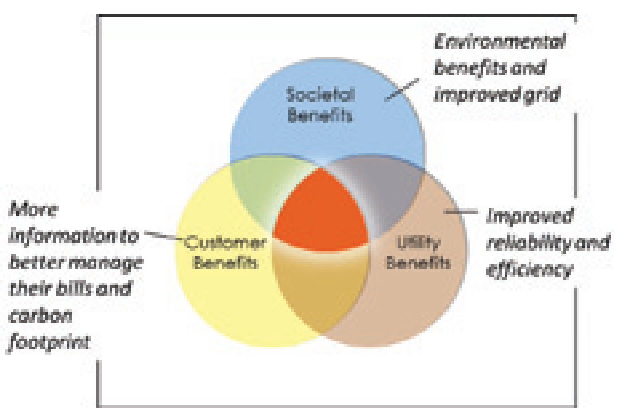
Automated services made possible by the new meter data management system will help decrease the time CVPS employees need to spend assessing an outage on site.

Remote and automated meter reading capabilities, as well as remote connect and disconnect capabilities, will allow utilities to operate more efficiently. In addition, the data analysis tools provide by the MDMS will provide utilities with more precise information to support distribution equipment sizing and outage management decisions. None of these capabilities would be possible without access to timely, relevant data that represents a more accurate gauge of *actual* energy needs and consumption.

In addition to the above capabilities, the MDMS will help CVPS to improve reliability through a better understanding of customer power quality levels. The vast volume of data that the MDMS accumulates will allow distribution system engineers to improve reliability and reduce costs by sizing distribution equipment based on a better understanding of actual system load. Rate analysts will be able to leverage the interval data stored in the MDMS to model new rate options in support of emerging technologies such as electric vehicles based on load patterns for different customer classes. System Operators will be able to develop new load control programs so that utilities can partner with customers to more efficiently manage load during peak periods. In short, the MDMS will serve as a foundational tool for enabling business intelligence across the utility enterprise.

Benefits to Customers

The Internet and ubiquitous communications networks that exist today are fundamentally changing customers' expectations about their interactions with service providers. With a bigger appetite for information, a continued need to save money and a heightened awareness of energy consumption, utilities must develop better ways to communicate with their customers (vs. ratepayers) at all points of contact. From their call center systems to monthly bills, utilities must take the opportunity to engage customers by providing them with richer information about their energy usage in a manner that helps customers to make informed choices about their consumption patterns and utility energy and rate programs.



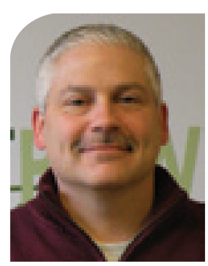
The new MDMS ultimately delivers benefits to customers by providing them with additional information about their energy usage.

As the MDMS helps the utility to streamline its business processes, it also gives visibility to problems and opportunities that previously went undetected. The MDMS will allow utilities to provide customers with interval billing information, as often as 15 minutes in some instances, enable flexible billing schedules, and facilitate time-of-use rates. Even more, utilities can achieve marked improvements in their ability to help customers make critical pricing decisions during periods of peak demand and pass those savings along to customers in the form of peak time rebates.

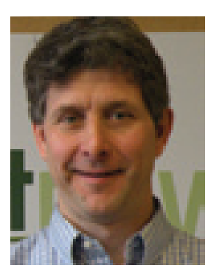
The right MDMS solution can capture interval billing data from the smart meter, sending that information into the legacy CIS, and providing the utility with full meter-to-cash functionality. Complete synchronization of data from disparate systems further allows utilities to efficiently generate bills, minimizing manual intervention by using the real-time information taken from handheld meter reading devices and smart meters. Each day CVPS synchronizes the day's customer transactions from CIS to the MDMS. These include transactions such as meter additions and replacements, rate changes, and general account changes. A complete synchronization of all CIS customer data is performed weekly between CIS and the MDMS. These processes ensure the MDMS and CIS are up-to-date and accurately reflect meter information necessary for the meter to cash billing process, from the smart meter to the MDMS providing the billing determinants for the CIS' daily customer billing.

CVPS has already proven an industry leading example of a well executed Smart Grid implementation with its CVPS SmartPower® project. CVPS is continuing to work to fully realize the full capabilities of its Smart Grid deployment. The MDMS has been a key enabler and a mission critical system in helping CVPS to achieve its Smart Grid objectives. As it begins the next phase of the project this year, CVPS looks forward to the continued benefits of the SmartPower project.

About the Authors



Jeff Breslen has been in the utility business for 28 years. He joined CVPS in 1985 as a software developer and has held various project management and leadership positions in the Application Development area. Jeff has an A.S in Data Processing and a B.S in Management Information Systems.



Todd Kowalczyk has been involved with technology in a variety of different positions for the past 25 years. He joined CVPS in 2008 and is the Manager of CVPS's Project Management Office. Todd has a B.S. in Computer Information Systems and an M.S. in Computer Science. In addition, he is a certified Project Management Professional and holds a Masters Certification in Project Management from George Washington University.

Dive into Data Analytics: Unlocking the Value of Smart Meter Data

By BK Gupta, Senior Manager, Product Management eMeter, A Siemens Business

With meter data analytics, utilities are recognizing the true value of their Smart Grid investment: Data. The business world today is undergoing a swirl of change. However, amid all the uncertainty, there is one matter, on which nearly everyone can agree: Data has become the lifeblood of any successful business venture. Going forward, all industry sectors, especially the energy industry, will look to harness the volumes of data stored in their corporate coffers and turn it into strategic and profitable business insights.

The term "big data," has emerged to describe the nearly inconceivable amount of data the business world now generates, and the job of analyzing it. Market research firm IDC, for one, sees "big data" becoming the next must-have organizational competency this year.[1] Consider the credit card companies that now alert customers to divergent patterns in their purchasing trends, in an effort to fight identity theft. And then there are the wireless providers that supply customers with reams of insight into not only how many text messages they've sent, but to whom and on what day.

Now, it's the utilities' turn to leverage their data. Thanks to the investments that many energy providers have made in advanced metering infrastructure (AMI) and meter data management (MDM) software, utilities are now poised to meaningfully analyze data and provide strategic insights to all levels of business users. This directly benefits executives, for strategic planning; engineers, for systems planning; and line personnel, for improving operations.

Analytics: Beyond Meter-to-Cash

In order to unlock the full value of AMI, utilities will need to implement MDM software capable of processes beyond basic meter-to-cash functionality. Meter data analytics provides utilities with the information they need to:

- Generate new customer insights
- Manage and even prevent outages
- Size distribution assets
- Implement preventive maintenance techniques
- Forecast and build predictive models for demand program planning
- Develop new rate plans and services for customers

It is meter data analytics that will enable utilities to tackle the biggest problems they face today, including failing transformers, unbalanced energy generation based on imprecise forecasts, operational inefficiencies and even energy theft. In the end, it is meter data analytics that will pave the way to a more engaged – and profitable – relationship with energy consumers.

But while many utilities are beginning to recognize the need for meter data analytics, they're often too bogged down with massive amounts of data and aging enterprise systems to even know where to begin. Energy firms will need to invoke IT leadership to help them develop an analytics capability that aligns with business strategy, uses accurate and up-to-date information and is based on a foundation that is extendable to everyone in the organization who needs these insights, with virtually no interruption to operational MDM functions.

[1] *Source: http://www.businesswire.com/news/home/20111201005201/en/IDC-Predicts-2012-Year-Mobile-Cloud-Platform*

MDM: The Source of Truth

Through investments in MDM systems, utilities now collect hundreds of millions of events and readings every day from sources such as the following:

- Meters (status, manufacturer, purchase date, events such as reprogramming notifications and tamper alerts)
- Transformers (ID, circuit section, circuit ID)
- Service points
- Customer accounts (type, status, billing cycle)

Collected data includes interval readings, register readings, meter-related problems, outage information, data quality information, and more. This data is heavily analyzed to ensure accuracy, calculate statistics and isolate any potential issues. This means the MDM is considered the "system of truth" for all data generated by smart meters, as well as the control point from the organizational network, down to customer homes and businesses.

By building on MDM with data-intensive applications, organizations can extract additional value from all this data. Just as credit card companies have fortified customer relationships by learning more about consumer behavior, desires and needs, utilities can improve customer satisfaction, boost revenues and become a more efficient utility as a whole.

Consider the following opportunities that meter data analytics enable:

- Identification of unbilled revenue: Meter events and usage information can help paint an overall picture of what's happening with a customer's energy usage over time. This unified view can help detect energy theft, meter tampering or equipment problems that may be affecting service levels. For instance, customers can be identified who have active accounts but no recorded usage, or the converse – energy usage but no active account. In many instances, water, gas and electricity providers are able to detect key indicators of unbilled revenue. For example, many utilities see customers with water usage but no electrical usage over months or even years, indicating a very likely candidate for investigation.
- Outage event analysis and prevention: Today, some utilities are still unable to verify an outage unless personnel physically visit the suspected problem area to confirm. With outage event analysis, however, the utility can know the exact piece of equipment causing a problem, along with the customers directly impacted by it. Utilities can obtain this more granular view of outage information by using outage information that is delivered along with meter readings to identify and track outages, rather than legacy phone-call-based systems where customers often had to notify the utility first when there was an outage. These outage event reports can help utilities understand the overall impact of outages, then drill down to find hot spots and particular problem areas in the distribution network. They can then isolate areas of high impact and work to understand how to address them.
- Meter quality assurance: Focusing on meter reading performance enables utilities to ensure AMI reliability. For instance, when meter readings are expected but not delivered, the system takes note, and calculates overall performance statistics for the AMI system. Utilities are made privy to problems they never would have been able to identify in the past.

Data analytics can open the door to a range of possibilities. From customer profiling to distribution planning, analytics unlocks the true value of the data utilities already collect.

Smoothing the Way to Analytics

Many users in the organization are well aware of the opportunities that meter data analytics pose. Because of this, analysts in various business functions are already chomping at the bit to begin analyzing this data. However, before making the data accessible to users, it's crucial to choose a meter data management platform with an analytics foundation that takes the following into consideration:

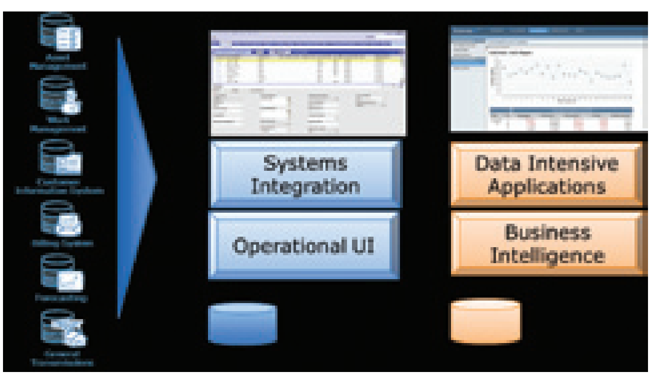
- **Ensure support for many use cases:** Organizations need to choose an analytic foundation that is flexible for as many use cases as possible. With the rich set of possibilities offered by meter data analytics, it would be wasteful and potentially harmful to future competitiveness to pick a system that limits you to just one capability. The energy industry is undergoing massive change, so it's important that the system is powerful enough to support possibilities that haven't been considered yet. The challenge is choosing an MDM foundation that is flexible enough to handle many different types of analysis, while also considering the specific needs of your everyday business processes.
- **The need for reliable, billing-quality data:** A second challenge is the need for reliability and trust in the data that flows into the MDM system. Some utility data that originates at customer sites – particularly in rural areas – is either never delivered or does not pass validation checks upon arrival, for instance, and needs to be vetted for accuracy.

- **No impact on meter-to-cash:** The third challenge is ensuring your system can use the data in the MDM system (the "system of truth") without impacting basic meter-to-cash operations in any way. As important as meter data analytics is, this capability cannot interrupt billing and other operational systems in terms of performance, data corruption or functionality. Bottom line: The analytics capability cannot threaten the utility's ability to collect revenues.
- **Near real-time:** Lastly, in order to retain its value to executives, engineers and operational staff, data analytics need to be performed in as near real-time as possible.

The ultimate goal is to establish a repeatable data analytics discipline and infrastructure to reduce the time, cost and complexity of each incremental capability, and with the lowest risk possible to the existing MDM functionality.

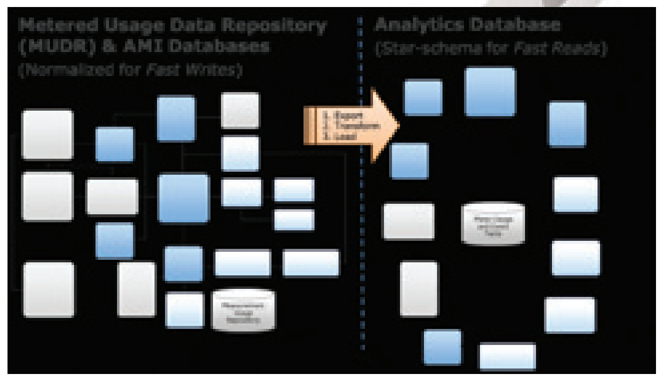
Building the Analytics Database

To preserve the sanctity of the MDM system and enable the essential capabilities described above, it's necessary to have a second system that is separate from but cohesive with the data stored in the MDM system. This separate system – we'll call it the analytics database – should be structured very differently from the MDM database. This is because the MDM database is normalized for "fast writes," since it needs to quickly record large volumes of real-time meter information. On the other hand, the analytics database needs to be normalized for "fast reads," since it needs to provide fast access to data for users looking for real-time insights.



All data should be fed into two different databases to ensure the sanctity of basic meter-to-cash functionality.

To leverage all the work that has already been done to create the MDM system, the analytics database should use a star schema design that classifies the attributes of an event into "facts," which would include the data itself, and "dimensions" that can give the facts context such as a customer's name or location. In the case of utilities, "facts" can include data interval values, register reads, billing values, missed reads and meter events. "Dimensions" can include meters, transformers, service points and customer accounts (see diagram, following).



The analytics database should be separate from the operational data base, and use a star schema design for fast reads of the data, ensuring real-time accessibility for all users.

Using the star schema design, the analytics database correlates measured data ("facts") along many "dimensions" (e.g., by postal code, by transformer, etc.) and stages them so that the data can be analyzed in many ways. This enables users to gain more understanding of events, as well as what they mean. For instance, analysts can correlate power outage events ("fact") with the transformers ("dimension") to identify faulty or aging infrastructure with a single simple calculation.

These analytics processes are data intensive and will likely need to be performed throughout the business day; yet another crucial reason for this entire system to be separate from the operational MDM database and avoid interruption of business-critical processes.

High-Quality Data

When it comes to populating the analytics database, the data needs to be extracted from the MDM database into the analytics database in a way that arranges the facts and dimensions in the star schema design. This is known as the extract, transform and load process, or ETL. For data that does not change very often (accounts, meters, transformers), the ETL can be scheduled on an hourly or daily basis. However, traditional ETL cannot be used for the billions of transactions that flow from AMI networks into the MDM system. Instead, a "real-time message bus" should be employed. The "message bus" can essentially grab the data before it reaches the meter-to-cash system, thereby avoiding performance disruptions but ensuring real-time data is available for analysis.

To ensure data is of the highest quality when it's loaded into the analytics database, other processes are involved, including data validation, estimation and editing. It's important, for instance, to isolate "bad data" (inconsistent or inaccurate data) and identify missing reads for meter readings that don't come in or arrive late. The latter can be calculated to understand more about AMI performance and service levels.

Dive into Data Analytics: Unlocking the Value of Smart Meter Data

Once the data is staged in a separate system that's isolated from the meter-to-cash processes, it's ready to be made available for online reporting, graphical representations of data and queries. As time goes on, you can continue to expand the system's value to meet the needs of limitless numbers of use cases. The beauty is, you've properly leveraged the investments made in your AMI and MDM systems without disrupting their functionality.

Align With the Business

Along with ensuring the best system design, it's also crucial that the meter data analysis system is in line with the business architecture; in other words, you first need to determine the business needs, and establish your strategic intent. Once you have strategic alignment, you can begin to understand what types of analysis you want to do and what benefits the analysis will provide.

Addtionally, the analytics system needs to meet the needs of users throughout the organization, from senior executives, to operations workers who interact with customers, manage the grid, plan maintenance and purchase equipment. That's why utilities need to establish a repeatable discipline and process for their analytics functions. The first time a new capability is rolled out, it might be an involved exercise, but with a sound infrastructure in place, each incremental capability will require less work.

Ultimately, utilities need to choose an MDM platform capable of creating an adaptive, analytically-based, data-driven organization, in which the metrics and data being collected and the analysis performed are all linked with the business's strategic priorities.

Data Analytics: Key to Survival

To win in business today, data is the name of the game. For utilities, one of the only ways to turn data into valuable information is through MDM software. For energy firms still in the MDM planning stages, it's key to choose a platform that enables the four essential criteria of meter data analytics: support for multiple use cases, high-quality data, no impact on meter-to-cash functionality, and the ability to operate in near-real-time.

In the end, data analytics will be the key to survival for energy providers. Utilities can only unlock the true value of their data by choosing a flexible and powerful meter data management platform with the proper data analytics foundation. By utilizing the data they already collect, utilities will finally be able to modernize and adapt to the fast-changing world of energy provisioning.

Building the Analytics Database

To preserve the sanctity of the MDM system and enable the essential capabilities described above, it's necessary to have a second system that is separate from but cohesive with the data stored in the MDM system. This separate system – we'll call it the analytics database – should be structured very differently from the MDM database. This is because the MDM database is normalized for "fast writes," since it needs to quickly record large volumes of real-time meter information. On the other hand, the analytics database needs to be normalized for "fast reads," since it needs to provide fast access to data for users looking for real-time insights.

About the Author

BK Gupta is a Senior Project Manager at eMeter, A Siemens Business, focusing a line of software, hardware, and partnerships that provide essential services for the Smart Grid.

Tucson Electric Expands Capabilities with Robust Fiber Network

By Jim Taylor, Director T&D Engineering, Tucson Electric Power and Tyler Kilian, IT Supervisor, Tucson Electric Power With Sten Nordell, CTO, Transmode

Tucson Electric Power Company (TEP), Tucson, Arizona, is the principal subsidiary of UniSource Energy (publicly traded on the NYSE under the symbol UNS). The company serves more than 400,000 power customers in Southern Arizona. To maintain and improve service delivery to its customers, the power company needed to upgrade its mission-critical optical network and increase capacity in order to maintain and improve service delivery to its customers.

The Challenges

TEP needed to expand its network capacity at its Tucson data center backbone due to a large increase in business application data used to maintain high levels of customer service. It needed to easily manage all the internal business application traffic on the network including e-mail, billing, customer-records, metering data, financial reporting and even large aerial photos of transmission lines. The company also wanted to link four facilities across a large metropolitan area, and add a separate storage network between two major facilities.

TEP was an early adopter of virtualization, with over 90% of their IT infrastructure virtualized. This has a significant effect on storage and backup requirements, increasing by terabytes of data per month and this data had to be replicated across the network. The company clearly understood the need to backup and store data after a major flooding incident in its service center. After considering its needs, TEP quickly realized they exceeded its 1Gb passive optical network, and must upgrade to an active 10Gb network.

Tucson Electric Power Overview

Challenges
Increased bandwidth demands for applications
Disaster protection strategy needed
Scarce technical resources

Results
Dramatic performance increase over same fiber infrastructure
Trouble free networking infrastructure managed by same staff
Multiple 10 Gb/s routes without incurring incremental operational costs
24-hour support and carrier-grade network management

Figure 1: The upgrade yielded dramatic performance increases and operational improvements.

TEP owned a dedicated dark fiber network, which ran between its four facilities across the same infrastructure it owned and managed for power distribution. Having the fiber was a considerable benefit, The company required a robust carrier-grade telecommunications solution that it could manage without incurring large ongoing operational costs. From their research, they believed a Wavelength Division Multiplexing (WDM) solution would meet their needs.

Wavelength Division Multiplexing (WDM)

In an optical network, information is converted to series of light pulses, which are transported along optical fibers and retrieved at a remote location. Theoretically, any light source could act as the information transmitter, but to achieve the distinct shapes of pulses needed for high speed data transfer and to restrict the light to a particular wavelength, only lasers are used in telecommunications systems.

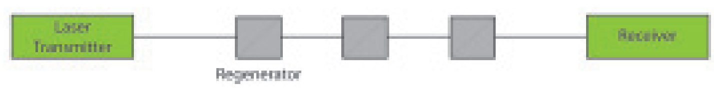


Figure 2: A simple optical link using a single fiber and having regenerators at intermediate sites.

The need for condensing, or multiplexing information on a single link arises because for most applications it costs less to transmit data at a high bitrate (e.g. Gbit/s) over a single fiber than it is to transmit it at lower rates (e.g., Mbit/s) over multiple fibers. There are two fundamentally different ways of multiplexing the lower bitrates onto a single fiber – *time division multiplexing* (TDM) *and wavelength division multiplexing* (WDM).

With TDM, the lower speed input channels are each allocated a defined timeslot on the outgoing higher speed channel – physically they are “taking turns” on the outgoing fiber. Time division multiplexing has been used in telecoms since the 1970s and was also the first technique employed in optical networks. Standards like the *Synchronous Digital Hierarchy* (*SDH*), with data rates denoted STM-1, STM-16 etc. and *SONET* with optical data rates denoted OC-1, OC-64, etc. are typical examples of TDM systems used in optical networks.

When using WDM, each input channel is assigned a unique wavelength (i.e. color of light), thus the channels can traverse the fiber “in parallel”. This technique enables multiplication of the capacity, but also bidirectional communication over one single fiber – a fact of significant importance when fiber is scarce or expensive to lease.

Figure 3: Wavelength Division Multiplexing (WDM)

Multiplexing of the wavelengths in a WDM system can be done in two different ways, depending on how much bandwidth each wavelength is allocated on the optical fiber: Coarse (CWDM) and Dense (DWDM).

Typically, CWDM systems provide up to 8 channels (i.e. wavelengths) in the 1450 to 1600 nm range. Some CWDM systems can allow for 8 additional CWDM channels in the 1270 to 1450 nm range, fully in accordance with the ITU-T Recommendation G 694.2 for a total maximum of 16 CWDM channels.

DWDM systems use a smaller transmission window than CWDM focusing on the 1530 to 1565 nm range and use much denser channel spacing. DWDM channel plans vary, but a typical system would use 40 channels at 100 GHz spacing or 80 channels with 50 GHz spacing. New amplification options, such as EDFA amplification, enable the extension of the usable wavelengths, greatly increasing the distance WDM systems can span. DWDM systems have to maintain more stable wavelengths/frequencies than those needed for CWDM because of the closer spacing of the wavelengths. Precision temperature control of the laser transmitter is required in DWDM systems to prevent “drift” off a very narrow frequency window of the order of a few GHz. This higher performance results in DWDM systems typically being more expensive than CWDM, although metro focused DWDM solutions can provide DWDM functionality for very close to CWDM pricing.

Some DWDM systems support transport using pluggable and software-tunable transceiver modules capable of operating on 40 or 80 channels. This dramatically reduces the need for discrete spare pluggable modules, when a handful of pluggable devices can handle the full range of wavelengths.

The actual choice of multiplexing technology – CWDM or DWDM – depends on multiple factors such as:

- Distance to bridge
- The number of channels needed (Channel count) now and in the future – DWDM gives 40 or 80 channels, while CWDM is restricted to 8 or 16
- The data rate used per channel
- The number of fibers available

Generally, CWDM solutions give the lowest entry costs for metro/access networks while DWDM is more cost-effective in metro/regional networks due to the higher number of channels and longer distances. In fiber-scarce areas DWDM solutions can also be a suitable option if more than 4 channels are required. Additionally a higher utilization of each wavelength could be a way to reduce the number of wavelengths required. This can be achieved with muxponders that perform electrical multiplexing of multiple client signals onto one wavelength. Finally, some vendors support a mix of CWDM and DWDM solutions on the same fiber to maximize fiber usage and scale a CWDM network to higher capacity.

The Tucson Electric Power Network

Initially, Tucson Electric Power believed that operating a DWDM solution over the network would be too expensive and complicated to deploy. TEP’s engineering team looked at a variety of solutions that would provide increased capacity, as well as the scalability to meet TEP’s five year plan. The solution TEP chose to deploy had to meet stringent cost criteria, and provide increased flexibility and scalability without adding on-going management and operational costs.

“We wanted an optimal way to introduce some DWDM equipment. We had small distances, high speeds and very large bandwidth requirements. This solution seemed to do exactly what we were looking for while anything else we could have chosen would have cost substantially more.”
– Jim Taylor, Director T&D Engineering

The primary decision was to invest in a networking solution that maximized the capacity of the company’s existing fiber infrastructure and not force them to buy bandwidth from a telecom operator. This decision was quickly reached on the basis of cost saving. After looking at four system vendors to understand the possible options and cost implications of specific optical networking solutions, TEP chose Transmode’s TM-Series optical networking platform because it best fit its needs for expanding performance and capacity.

Economics was an important factor in the vendor selection decision. The increase from a passive 1 Gb network to an active network with 4x 10Gb pipes and 4x 1Gb pipes was a major change for TEP. TEP also wanted a flexible network that increased functionality and left room for expansion. The network TEP installed consists of 4 nodes carrying Ethernet traffic.

The topology of the network means traffic can be picked up and dropped off at any of the nodes. Even with the nodes as little as 15km apart and carrying standard traffic this network architecture requires auto-power-balancing.

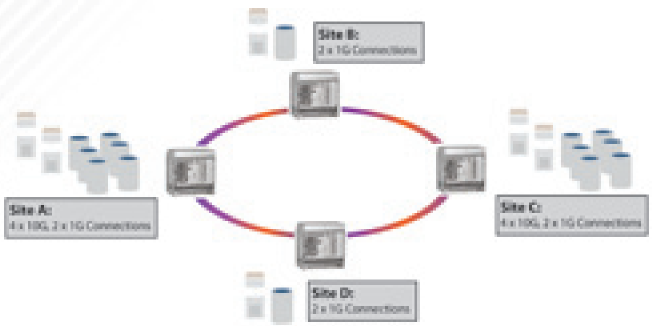


Figure 4: TEP has 4 sites, with multiple 10G and 1G connections

Auto-power Balancing

In DWDM networks with closely spaced channels, it is imperative to maintain equal power levels among the different channels. This is especially important in dynamically provisioned optical networks in which it is possible to add and drop multiple wavelengths. The TEP network running across four nodes with the two primary nodes at each end of the network and two intermediate nodes has been designed to carry traffic from the two end points and pick up and drop traffic at the intermediate sites.

In such cases, there can be a significant mismatch in the optical power levels and therefore in the optical signal-to-noise ratio level among the different channels. An irregular optical power level can also introduce non-linear effects and cross talk from high powered to low powered channels. Some vendor solutions eliminate these issues because of its built-in auto-power balancing feature, which is more common on carrier type platforms.

Network Management and Green Power

TEP was concerned that it would not have the optical experience or skills to effectively manage a DWDM network. However, since the deployment, TEP has not needed to add any extra staff or take existing staff away from other tasks. “We check on it to make sure there are no alarms, but in general it just works” said Jim Taylor. Finally, as a power utility company, TEP is proud of its green credentials and although power usage was not a major cost concern for the power company, the solutions low power hardware design did meet TEPs criteria for energy savings.

Results

The DWDM network solution has enabled TEP to transform its operation, greatly increasing capacity and capabilities with a resilient network. Furthermore, the network can be maintained by the same staff, with little trouble. For the IT department, the main benefit is that they can now work more efficiently.

“It’s like a quantum leap. Once you have this system you start finding all the things you can do you would not have considered before. We now have the ability to engineer our systems as you would in a single facility but now we can do it across facilities.”
– ***Tyler Kilian, IT Supervisor***

By deploying a networking solution that meets its current needs and is flexible enough to meet its future expansion plans, TEP has minimized its investment in capital expenditure and on-going operational costs. It has a network that is reliable, cost efficient and easy to use. TEP can now add and delete channels easily with great flexibility. The existing team can manage the network without adding expensive headcount.

About the Authors

Jim Taylor is Director of T&D Engineering and also also acts as TEP’s technical lead for Smart Grid initiatives. During his ten years at TEP, Jim has worked as a Senior Substation Engineer, Metering Services Supervisor, Protection, and Communications, Automation and Metering Engineering Supervisor.

Tyler Kilian is IT Supervisor at Tuscon Electric Power, where he is responsible for the multi-disciplinary team that manages and engineers company Local, Wide-Area, and Metro-Optical Ethernet networks as well as geographically dispersed Voice systems, including a separate ACD/IVR platform. Tyler also manages multiple Data Center environments for corporate and operational equipment. and the company’s regulated Energy Management System (EMS) network.

Sten Nordell is Chief Technology Officer, Transmode

Sten Nordell is Transmode’s CTO and drives Transmode’s strategic technology roadmap to deliver the next generation of optical IP/Ethernet systems. As one of the few people in the industry to have senior-level experience in building networks from the operator’s perspective and in designing systems as a vendor to meet operator needs, Sten is highly regarded by his peers for his regular presentations at numerous conferences and shows worldwide.

Expansion and Consolidation in Retail Power

By Justin L. Courtney,
Senior Vice President, Stephens Inc.

Although the retail power markets started to deregulate in 1978, the tiny state of Rhode Island was the first state to offer retail choice in 1997. The REP market has since quietly amassed scale as 15 states have joined the cause with much of the activity in the past five years. Texas proved to be a chief contributor to the success of the REP market when, in 2002, the state implemented a bill for retail competition for all customers served by investor-owned utilities. Furthermore, the Public Utility Commission of Texas approved new deregulation rules in 2004 and 2010, bringing the Texas market to $35 billion in competitive sales.

Over just the past ten years, the existing U.S. market for competitive electricity has grown an estimated $30 billion (now reaching the $180 billion plateau), and U.S. competitive power sales are only expected to increase, projecting as much as 10% in 2011. Few industries of this size have remained "under the radar" for so long – but that era has finally ended.

In 2011, 22 REP transactions were announced – nearly 40% of all REP transactions conducted over the past 10 years. To reference a few of the recently announced acquisitions:

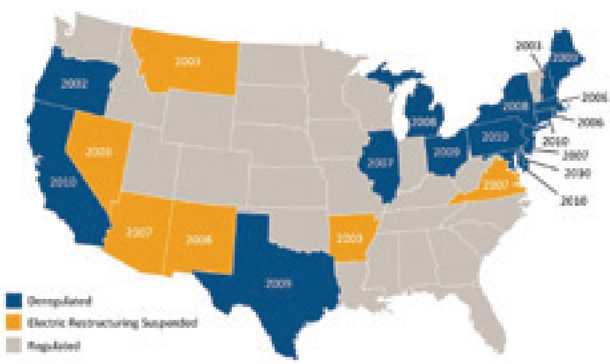
RECENT TRANSACTIONS IN THE REP SPACE	
Just Energy	• Just Energy acquired Fulcrum, dba Tara Energy and Amigo Energy, for $100million. Just Energy also purchased Hudson Energy from Lake Capital for $300 million in 2010 and Universal Energy for $330 million in 2009.
Direct Energy	• Direct Energy purchased Gateway Energy in March for $90 million from DLJMB, as well as the September purchase of First Choice Power from PNM Resources for $270 million.
NRG Energy	• NRG purchased EnergyPlus in August for $190 million NRG also purchased Green Mountain in 2010 for $350 million and Reliant Energy's Texas operations for $288 million in 2009.
Constellation Energy	• Constellation acquired Startex Power for an estimated $190 million and MX Energy from Charterhouse and its debt holders for $175 million in May. Exelon announced its merger with Constellation, valuing the combined company at $34 billion in April.
Duke Energy	• Duke Energy and Progress Energy announced a merger in January, which valued the combined company at $37 billion.
IGS Energy	• IGS, the largest natural gas retailer in the U.S., purchased Accent Energy in February from Angelo Gordon.
Dominion Resources	• Dominion Resources added Simple Power to its portfolio; the company was enfolded into Cirro Energy, Dominion's TX retail business, in August.
AES	• AES announced its $4.8 billion purchase of DPL in April, bringing an Ohio competitive business to their portfolio. DPL acquired MC Squared Energy Services in March.

History of U.S. Electricity Deregulation

To provide just a brief timeline of representative major events in the deregulation process:

1978	Congress passed the *Public Utility Regulatory Policies Act (PURPA)* which laid the groundwork for deregulation and competition by opening wholesale power markets to nonutility producers of electricity.
1992	Congress passed the *Energy Policy Act of 1992 (EPACT)*, which promoted greater competition in the bulk power market. The Act chipped away at utilities' monopolies by expanding FERC authority to order utilities to allow independent power producers equal access to the utilities' transmission grid.

1996	The Federal Energy Regulatory Commission (FERC) implemented the intent of the Act in 1996 with *Orders888 and 889*, with the stated objective to "remove impediments to competition in wholesale trade and to bring more efficient, lower cost power to the nation's electricity customers."
2002	The state of Texas passed *Senate Bill 587* on January 1, 2002 that restructured the electric industry in TX. The bill provided retail competition and customer choice; transmission and distribution remain regulated by the Public Utility Commission of Texas.
2005	President Bush signed into law the *Energy Policy Act of 2005*, which decreased limitations on utility companies' ability to merge or be owned by financial holding / non-utility companies. This led to a wave of mergers and consolidation within the utility industry.



Electricity Deregulated States and Most Recent Restructuring Activity
(Source: Stephens Inc.)

Factors Driving M&A

Today, REPs sell electricity to customers and handle customer service and billing; and compete for customers by offering pricing options, renewable energy options, added customer service benefits, or other incentives. The market is overcrowded with more than 200 retailers (116 in Texas alone), and there is a finite amount of capital and resources available to smaller providers. Approximately 50 REPs have eclipsed the $100 million revenue mark. Only two pure-play retail providers are publicly traded: Just Energy and Genie Energy (IDT Energy). Only 7 of the top 50 REPs are backed by private equity (mostly minority). However, this burgeoning industry is attracting the attention of strategic and financial investors alike.

Among the financial sponsors already in the REP space: Black Forest Ventures has a minority stake in TriEagle Energy; Champion Energy , a portfolio holding of Crane Capital; MVC Capital, Inc. holds US Gas & Electric Inc. and Plymouth Rock Energy; Energy Futures Holdings Corp (formerly TXU Energy) is owned (via leveraged buyout) by KKR, TPG and Goldman; Hunt Investments holds a minority investment in Ambit Energy; Platinum Capital is invested in Glacial Energy; and NGP Energy Capital is invested in Stream Energy.

To get financial backing requires more than a good sales pitch. Although some independent REPs (not affiliated with incumbent generation) are drawing $300-900 million per year in sales, they find it difficult to raise capital without demonstrable evidence of sustainable competitive advantages:

- Scale and expanded footprint
- Unique brand and reflective reputation
- Portfolio of creditworthy customers on fixed-priced contracts
  or higher margin variable contracts
- Product differentiation and diversification
- Proprietary technology along customer acquisition, service and billing
- Niche marketing approach such as affinity programs, network marketing and aggregation
- Smart grid technology adoption (automation, smart metering, demand response, dynamic pricing)

Such differentiating qualities also extend to the buyout process, as various bidders across the power industry are actively pursuing opportunities. Companies with defendable growth prospects and sticky customer platforms are positioning themselves for sale, exacting attractive EBITDA multiples. Consider NRG's acquisition of Energy Plus, paying close to 8x EBITDA. Energy Plus capitalized on its unique affinity marketing channel – airline miles for power purchases. Note that Just Energy has consistently traded at a double-digit EBITDA multiple, leaving plenty of room for private-to-public arbitrage.

So who are the bidders in this highly fractured REP marketplace?

1. **Larger independent retail energy providers** with sufficient scale or financial backing are logical buyers, as they seek to increase market coverage, gain economies of scale and take out competitors Examples include Just Energy, Liberty Power, Champion Energy, Spark Energy and IGS Energy. More often, their interest lies in buying up the books of business of smaller players, expanding their footprint and product offerings. One takeaway is that four independent REPs (Glacial, Spark, Liberty and Just) are licensed and operating in all 16 deregulated states. Only Constellation and Dominion, among the incumbents, are active in more than 10 states.

The acquisition of the Abacus book by Spark Energy is an example of something that the bureaucracy of an incumbent would not allow. The book of 6,200 customers was transferred and paid for over a weekend. Just Energy's acquisition of Fulcrum followed a similar – yet slightly longer – timeline.
There was no process and no other bidders.

2. Since independent retailers came to the market, giving consumers more flexibility and choice in providers, **incumbent utilities** have lost a large percentage of their retail customer base. Take TXU, the largest incumbent in Texas, which saw its residential customer count decline from 2.5 million in 2002 when the market opened to 1.7 million this year, a 30% drop. Regulated utilities seeking to recapture customers have been active acquirers . NRG, Constellation and Direct have all made multiple REP acquisitions. In fact, 18 of the 19 publicly traded utilities that have REP divisions have made at least one REP acquisition. Incumbents are starting to realize that their rate-based strategies aren't applicable in a market won via creative marketing. Most utilities have kept their prizes as separate divisions to preserve this edge.

As listed above, Constellation Energy picked up MX Energy and StarTex Power, helping Constellation expand its footprint and adding to its retail book. Benefits of these two deals also included increased scale and scope across the value chain, strength in market position to exceed one million mass market customers and new geographic reach.

As referenced above, NRG acquired Energy Plus. The attraction was obvious: Energy Plus' channel as the largest affinity marketer with previously successful credit card marketing companies provides credibility to their model; furthermore, they benefit from a rapidly growing network of almost 100 industry-leading partners and associations. The deal increases NRG's scale in the Northeast – over 90% of Energy Plus customers are in that region; and strengthens NRG's retail base by adding a high growth platform to match their generation in the region.

3. **Integrated energy companies** could leverage their existing strategic relationships. To date, the likes of BP and Shell have decided to stay in the wholesale business as they know commodities rather than customers. This trend is unlikely to change as wholesalers see plenty of business in supplying the retailers. The market for bank financing is non-existent for retailers without generations assets, save Spark Energy, IGS Energy and Just Energy, all three of which have syndicated credit facilities. Retailers in turn, rely on supply credit and sleeve arrangements to procure the commodity. As margins continue to compress at the wholesale level we may see some new strategies.

Hess is relatively integrated from wholesale to retail, although they continue to operate exclusively in the Northeast. As a leader in international wholesale energy markets, EDF Trading is an example of a forward thinker – they made a minority investment in their largest wholesale customer, Champion Energy. EDF is also supplying large commercial customers at the retail level. Twin Eagle is another wholesaler to watch, with the possibility of expanding their services beyond wholesale and into retail.

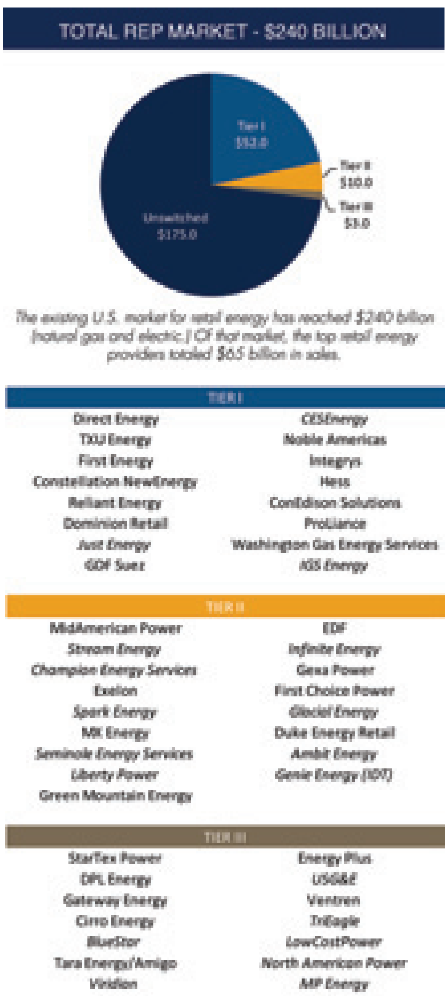
4. **Leading energy services / efficiency companies** are closely monitoring the REP model. They should be interested, but they are cautious about the commodity risk. Find a way to transfer that risk and preserve the customer relationship, and this combination will transform the sector.

Leading ESCOs that should be taking a closer look would include Silver Springs, Comverge, Enernoc and Ameresco. Blue Star Energy is an independent REP that has already integrated energy efficiency consulting into their approach – they were recently acquired by AEP. Large incumbents such as FirstEnergy and ConEdison have pushed this connection for some time now. The energy service platform is yet another way to retain customers. Home automation, demand response and other energy technology providers may consider pairing up with REPs to offer this integrated offering.

5. With all of that said, the future of the REP sector lies in the past. **Telecom acquirors** have yet to fully appreciate what a REP really is – a customer acquisition and retention machine. Now think about bundled services. Now think about the size of your electric bill versus your cell phone bill. It's coming, deregulation and eventual consolidation. Only this time, the independents do not have to rent capacity from the incumbents. The playing field is level.

IDT Telecom was the first telecom company to enter the retail electric sector. They are now the largest independent REP in NY and the first U.S. listed REP. They were spun off from IDT on October 31, 2011 under the name Genie Energy. Paetec Energy, one of the early telecom players in retail energy, was acquired by Windstream for $2.4 billion in August of last year.

Cincinnati Bell and Viridian are yet another twist. Verizon Power? AT&T Energy? Someday. Both are already offering home automation and energy management programs. Find a way to transfer the commodity price risk back to the wholesalers and you have a game changer.



Source: Stephens Inc.
The existing U.S. market for retail energy (natural gas and electric) has reached $240 billion. Of that market, the top retail energy providers totaled $65 billion in sales.
[Please note that this listing is purely representative, and does not purport to be a complete reference to all REPs. Italics represent independent REP providers.]

Conclusion

Today, less than 20% of total U.S. power customers have switched (up from less than 10% a few years prior), but nearly half of customers in deregulated markets have switched, and this trend is continuing. Witnessing the success of the Texas model, states such as NY, PA, GA, CA, MI, OH, CT, and DE are following suit. As more states deregulate power markets, opportunities exist for REP entrants to take share from the utility incumbents.

This creates a confluence of factors leading to more industry consolidation in the near future. The winners and losers have yet to be identified, but the level of M&A activity suggests that a transformation of the deregulated power markets is underway.

About the Author

Justin L. Courtney is a senior vice president at Stephens Inc., where he provides M&A, capital raising and supply financing services in the Power and Resource Solutions group. He is responsible for subsector coverage of retail energy, energy efficiency and energy infrastructure. Stephens Inc. is a full-service investment banking firm headquartered in Little Rock, AR, with offices across the country. For further information, contact Justin in the firm's Dallas office at (214) 258-2748 or via e-mail at *justin.courtney@stephens.com*.

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THE BIGGER PICTURE

BY GREGORY K. LAWRENCE, PARTNER
CADWALADER, WICKERSHAM & TAFT LLP

Line Re-Rating: A Bridge Over Generation Interconnection Troubles

Common development wisdom characterizes portions of the U.S. transmission system as antique and the generation interconnection study and queue process, especially for renewable power as, at best, opaque. As energy lawyers, charged with attaining interconnection and transmission rights for developing generation projects – often in challenging locations – we appreciate how engineering drives regulatory and contracting solutions to difficult interconnection problems such as costly network upgrades paid by the project. Without cost-effective and timely solutions, interconnection issues can wreck a project's timeline, upset underlying power purchase and other material agreements, disturb financing expectations and, ultimately, threaten a project's overall viability.

One potential solution to high-cost network upgrades warrants attention: achieve the interconnection through transmission re-rating work, which can be performed ahead of schedule and below the cost of the planned network upgrades while maintaining reliable transmission operations. Not a bad result.

Several Transmission Owner/Operators ("TO") have established a multi-step process by which generation facilities, including renewable energy projects, may request interconnection to the transmission grid. First, the project submits an application for interconnection, after which it is assigned a "queue" position. The generation project provides information including a facility one-line diagram detailing proposed interconnection points, voltage levels, thermal ratings, generator nameplate and other data.

The transmission provider then conducts a series of studies, paid for by the project by agreement. Projects are often required throughout the study process to make certain financial deposits or demonstrations of control over land necessary to construct the generation facilities.

If these deposits or demonstrations of control are not made, the project's application may be withdrawn and the project's "queue" position eliminated. Certain transmission providers may simultaneously study several projects requesting interconnection, grouped geographically as a "cluster". Clustering can be helpful but may also further complicate matters for each individual project seeking timely, cost-effective interconnection. For example, if a member of the cluster decides to forgo its request, the cost to the remaining members associated with needed network upgrades may increase significantly. These costs also may go away entirely, however, if the upgrades are no longer needed due to the exiting project's capacity leaving the cluster.

TOs generally conduct a preliminary interconnection system impact study ("PSIS") to estimate the cost of any network upgrades necessary to reliably interconnect the generation facility. Depending on the results of the PSIS, the project may then undergo some form of definitive interconnection system impact study ("DSIS") which is similar to the SIS and designed to more specifically estimate the cost of network upgrades for which the project will be liable. If the project agrees with the findings and, based on the costs identified in the DSIS, wishes to proceed with interconnection, the TO will commence a facility study ("FS").

The FS will further detail the costs of the required upgrades to the physical interconnection facility. If the project elects to proceed, the project will then negotiate a Generation Interconnection Agreement ("GIA") with the TO. If the parties cannot agree on terms in the GIA, the project may request termination of negotiations and request that the TO submit the unexecuted GIA to FERC for resolution or initiate dispute resolution procedures under the TO's tariff.

Often generation projects – including renewable projects – stumble during the impact study or even the GIA negotiation phases over the interconnection costs, timing delays, and potential changes to equipment location and nameplate rating posed by the TO's proposed network upgrades.

If so, the developer and its counsel should dig deeper. The TO may be correct given its traditional system impact analyses, but the project should ask itself whether such potential upgrades are truly required to interconnect the specific project. The project should consider whether certain upgrades might be driven by extraneous TO considerations or based on static study methods. The project should collaborate with the TO to suggest well-founded, less costly and more timely solutions. One solution is to study – and possibly re-rate – the existing transmission line capacity, which might optimize the existing system and obviate the need for costly upgrades or interconnection delays.

An example drawn from experience:
A wind generation facility was being constructed in a particular region of the United States.

After various impact studies, the project was initially going to be limited to interconnecting only a portion of its nameplate capacity until expensive network upgrades could be completed at the project's expense. Need for these upgrades was based primarily on potential transmission thermal limitations that could occur in very limited circumstances. Construction of the proposed costly network upgrades was estimated to take several years – a material blow to the project. Initially interconnecting a portion of the project's planned turbines to allow for upgrades, furthermore, would have negatively impacted other contracts and schedules. This type of "phased" interconnection also could have disrupted the full nameplate assumptions underlying existing off-take arrangements.

After several months of cooperative effort, the project, the balancing authority and the TO determined that a relatively simple and low-cost transmission line re-rate could be performed to solve the thermal constraint and, importantly, obviate the need for the significantly more extensive network upgrades initially proposed.

In addition, depending on timing requirements, all turbines could be interconnected at one time (satisfying the off-taker) so long as special control systems were in place to automatically reduce output during the transmission re-rate work. Specifically, a system could be put into place to prevent against thermal limitations occurring during the line re-rate work. The project also could agree to install equipment providing for automatic power output limitation at a certain MW level, automatic output breaker tripping capability, and/or TO circuit breaker control to curtail the project's output for reliability purposes.

Once interconnected, the re-rate work was performed well ahead of schedule and at a fraction of the cost of the planned upgrades, all without negatively impacting reliability. This creative re-rate solution unlocked access to already existing capacity that otherwise would have gone unused. The solution allowed for the project to meet its obligations under its off-take agreements in a timely manner and at a lower cost.

Dynamic line rating is not a novel approach to addressing reliability issues. TOs determine a maximum conductor temperature for each transmission line that sets the maximum transfer capacity. TOs often rate transmission lines with a fixed (static) rating based mainly on conductor and weather conditions. TOs often use worst-case assumptions calculated years or decades ago to set transmission line thermal limits, including record temperatures, low wind speeds, and failing conductors.

Technology innovations have increased the ability of TOs to maximize transmission line capacity without costly and time consuming upgrades to accommodate viable generation interconnections. Specifically, a transmission grid's power transfer capacity is not constant and is primarily controlled by three elements: stability, voltage limits, and thermal ratings. As the Valley Group recently stated in its paper *Dynamic Line Ratings for Optimal and Reliable Power Flow*, "thermal/dynamic line ratings represent the greatest opportunity to quickly, reliably and economically utilize the grid's true capacity."

Dynamic ratings apply here because transmission conductors have "thermal inertia"; thus, taking time to change temperature. Because of thermal inertia, a TO often has ample time, under exceptional system events, to determine if and what operator intervention is necessary under these exceptional situations. TOs may be able to utilize this and other assumptions to re-examine the maximum available capacity for their transmission lines under specified conditions and thus find room for new generation, including renewable projects.

Moreover, in recent FERC proceedings, parties have identified optimization studies and re-rating as viable alternatives to costly upgrades, especially for alternative power. For example, the April 12, 2010, *ISO-RTO Council White Paper, Variable Energy Resources, System Operations and Wholesale Markets*, indicated that SPP has "explored whether to re-rate constrained transmission lines to allow more wind power onto the lines." Because wind generation is primarily at off-peak times and that the transmission carrying capability is rated at peak times, it is thought that more wind generation potentially could be carried on transmission paths than conventional rating criteria would suggest.

ISO-NE also recently filed comments in the FERC's rulemaking effort, *Integration of Variable Energy Resources* ("VER"), Docket RM10-11, responding to a question regarding how have redispatch and curtailment practices changed with increased numbers of VERs. Supporting financial incentives for dynamic line rating investment by TOs that allow a better understanding of real-time transmission capability, ISO-NE responded:

"Redispatch and curtailment practices that depend on static line ratings can artificially limit the usable energy from VERs. Dynamic Line Rating (DLR) technologies facilitate the integration of VERs (such as wind energy) into the existing transmission grid as well as onto new transmission lines. Reliable DLR technology takes into consideration real time weather conditions, particularly wind variability, along the transmission line, and provides the operator with a line rating in real time that reflects actual versus assumed static weather conditions."

In the majority of the time, DLR allows for more transmission capability over the same line because the actual weather conditions are more favorable than those assumed. Specific case studies exist to support this finding. This is particularly true in case of renewable energy, especially wind farm generation. A transmission line connected to a wind farm is more likely to see more wind than that assumed when the static rating was established.[1]

We agree: line re-rating is an important tool with which to navigate interconnection troubles.

ABOUT THE AUTHOR

Gregory K. Lawrence is a partner in the Energy and Commodities (E&C) advisory group of the law firm Cadwalader, Wickersham & Taft LLP. Mr. Lawrence focuses his practice on regulatory proceedings, projects, negotiations, enforcement and agency litigation relating to the wholesale and retail electricity and natural gas industries. Mr. Lawrence would like to thank Terence Healey, special counsel, and Ben Chesson, associate, with Cadwalader's E&C advisory group, for their significant contributions to this article.

[1] *Other commenters urged increased deployment of Phasor Measurement Units and other smart grid technology not only to enhance reliability but also to enable more efficient use of the grid, for example, through a switch from static to dynamic line ratings.*

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

SECURITY SESSIONS

Warning! Warning! Alien Presence Detected, Will Robinson!

Welcome to the latest installment of Security Sessions, a regular feature focused on security-related issues, policies and procedures. In prior columns I have discussed some of the various types of technologies and methodologies that can be applied to protect your critical computer-based automation systems from cyber threats. We have discussed firewalls and the use of a multi-layered defense in depth strategy to guard your network connections. But I have also tried to make you aware of the less obvious ways in which 'threat agents' (a cute term for those people who wish you harm) can get at your cyber assets including 'SneakerNet' (the way that Stuxnet is presumed to have been introduced into the Iranian nuclear enrichment facilities) and, via the supply chain (e.g., hidden code/logic in the products you buy). Some readers have asked if there is a way to guard these attack pathways too. The simple answer is "yes" using proven intrusion detection and prevention technology. – ***Tim***.

In previous columns, we've talked about all of the things you can use to guard the primary entryways to your computer-based automation systems and critical digital assets. If you create a DMZ between your plant automation network and your corporate network, and use it to isolate the two, you make it hard for an attacker to get into your plant systems from that direction. Most corporate IT departments will have already done a reasonable job of using a DMZ, and some great honking-big enterprise firewall, to insulate the corporate network from the actual Internet.

So, an attacker coming across the Internet has two major barriers to traverse and, even if they compromise a computer on the corporate network (which happens all too often due to unprotected web surfing and unsafe email practices), they still have another DMZ blocking their access.

This is not to say that this final barrier can't eventually be overcome – never underestimate the innovative talent and downright sneakiness of your adversaries – but it will slow them down and maybe give you a chance to respond before they are able to cause any damage. Both the ISA (the SP.99 committee) and NIST (in their 800-82 special publication) highly recommend this approach, and I agree with them. A DMZ between plant site/ECC automation systems and the corporate WAN can also help to control and manage 'authorized' remote access to critical systems and data flows going 'up' to corporate business applications.

Of course, if you are casual in your use of wireless technologies in your plants, or if you allow vendors and/or your own personnel to have remote dial-in connectivity to critical systems and/or networks, then all bets are off. However, one would hope that those issues would be addressed and appropriate action taken to eliminate those attack pathways as part of a comprehensive cyber security program. I personally have never been convinced that wireless networking – which, as I've pointed out in previous columns, is different from wireless instrumentation technology – should ever be allowed near a critical automation system, let alone connected to one. Having said that, many plants are investing heavily in wireless networking infrastructure for its convenience and to reduce wiring costs.

To my way of thinking, this is dangerous if it provides access to critical systems (including security systems), but if you must go down that path then, in addition to having IEEE 802.11i encryption and authentication implemented on all your wireless devices and access points, having some means in place to monitor for malicious and unauthorized wireless traffic is essential.

We have, in the past, bemoaned the problem of orphaned automation systems; those SCADA and DCS (and even PLC-based) systems still essential to operations, but which are no longer supported by the vendor – often because the vendor no longer exists.Those systems, if they are less than 10 or even 15 years old, probably have an underlying platform that is modern enough to include TCP/IP-Ethernet networking and a MS-Windows or Unix-like operating system. That means that they are susceptible to current cyber attack methods and techniques as well as being vulnerable to a lot of the malware circulating through the cyber environment. Since no one would likely risk causing a problem by making anything but essential functional changes to such systems, it is unlikely that any security-related patches, if any exist, would be (or are being) installed. For such systems the best protection alternative is to isolate them with an "air gap" – and no, wireless connectivity is NOT an air gap! But if you can't do that then you need to insulate them using firewalls and closely monitor all communications traffic directed at, and coming from, those systems. But of course neither of those strategies will protect against SneakerNet and supply chain threats.

So, to the point I made in my opening comments: what can be done about threats and attacks that make use of the manual delivery of malware via portable media and devices (a.k.a. SneakerNet) and malware buried in the bowels of software and systems you purchase? [And by 'malware' I mean anything from a secret 'backdoor' user account and password to a virus or worm that spread to other systems and wreak havoc.] Obviously you can try to have procedures and policies to prevent SneakerNet attacks. You can sheep-dip (meaning thoroughly erase) all the USB "thumb drives" and virus scan all the laptop PCs, but that is a rather daunting task, especially given the range of digital devices we all use these days.

Everything from laptop PCs and tablets to smart phones and digital cameras can be used to transport and deliver malware. For example, there are viruses that spread from cell phones to laptop PCs via Bluetooth wireless communications, and there have been documented cases of network-connected printers being supplied with driver software that included a secret backdoor (Trojan) virus. You probably can't realistically perform scans on everything that could potentially be used as a transport medium; however, you ought to give it a good try! Moreover, if there actually is secret code hidden in any major application program, just waiting to be activated, we don't yet have the proven ability to determine that fact and find the offensive code. And what about that trusted insider that has reached his/her limit and decides this is the day to "go postal"? What can you actually do to protect your critical computer-based systems in those cases?

One of the more powerful IT cyber security technologies available to protect your cyber assets is the intrusion detection and prevention system – or "IDS/IPS" – which is sometimes combined as "IDPS". An intrusion detection system [IDS] watches for unusual, abnormal and obviously-malicious activities that are happening within a computer and/or on the networks that interconnect computers. Properly configured and applied IDS systems can detect the fact that a program has been infected with a virus or that a worm is trying to pass a copy of itself over a network. Likewise, an IDS can identify, and even block, a wide range of network-based probes and attacks.

If you have purchased software that turns out to have a built-in 'time-bomb' (that is, code that is dormant until, for example, a pre-designated time/date is reached), the activation of the hidden functions will usually cause the program to act in an anomalous manner, which will alert the IDS. For example, a savvy operator might ask: *"Why is that spreadsheet suddenly trying to communicate with a computer in China?"*

If malware is delivered on a portable device, the act of trying to install and execute it on the target computer can be identified and possibly blocked by an IDS, but before I make IDS technologies sound like the 'Holy Grail' of defenses, let's cover some basic facts about their strong and weak points...

Intrusion detection technology falls into two broad categories, with both types complimenting the capabilities of the other. The first type of detection technology is called "host based" intrusion detection or "HIDS". This technology involves installing special software (called an 'agent') onto the target system(s) and letting that software use some of the processing power and other resources in order to monitor the actions of application programs and users. HIDS technology is not available for all computer platforms; basically it's for MS-Windows and Linux variations. It actually buries itself into the operating system using the same technique as a "root kit", which is a very, very dangerous form of malware. In that mode, the HIDS can control access to the file system, network connectivity and the ability of a program to run (a capability called "whitelisting"). As part of their installation it is typical for a HIDS to compute and securely store a 'hash code' value for every file, so that it can spot any unauthorized or clandestine modifications and additions, such as being infected with a virus.

It is also typical for a HIDS to gather operating statistics on applications so that it can spot anything new and different about how a program behaves. On the negative side, if you are already infected when you install a HIDS, it will consider the infection, and how infected programs are acting, as its "normal". Also, though in most cases the resource utilization caused by the presence of the HIDS 'agent' is negligible, there may be instances where it could unacceptably impact real-time behavior and system responsiveness.

The second type of intrusion detection technology is called "network based" intrusion detection or "NIDS". This technology is not intrusive and does not require the modification of any system or the installation of special software on the computers being protected.For that reason it is applicable to orphaned systems and really to any systems or devices that communicate using TCP/IP-Ethernet networking. A NIDS is generally one or more separate computers that connect to a LAN and watch all message traffic between and among the systems/devices on the LAN. Going back to the beginning of this article, when a DMZ is created to isolate corporate networks from plant networks, it is a good idea to have a NIDS situated on the "plant side" of the DMZ so that all traffic 'up' and 'down' can be examined.

In fact, it's a good idea to place the NIDS in series and have it block malicious message traffic. Incidentally, in that case it's considered to be an intrusion prevention system (IDPS), not just a detection system.

Likewise, within a plant site, if there are further internal network segments that connect critical systems, it is recommended to have a NIDS watching that traffic as well. A host-based intrusion detection system has capabilities not found in a NIDS, but since a NIDS is essentially invisible to the systems and devices whose message traffic it monitors, it is possible to use a NIDS in pretty much any situation. Modern LANs are built with Ethernet switches, and usually it is possible to set up a 'mirror' or SPAN port on a top-tier switch where a NIDS can be attached and receive a copy of all of the traffic. NIDS can detect a wide range of attacks and malware, and some can even be configured with customized rule sets that allow industrial protocol message traffic (e.g., the IP versions of Modbus or DNP3.0) to be monitored. NIDS that support user-defined rules that use the BPF (Berkley Packet Filter) syntax can examine such message traffic to see what commands are being issued, and register addresses that are being read/written.

Network intrusion detection can also be applied to monitoring wireless networks. By placing an NIDS at the access point(s) where wireless users are routed onto a wired LAN, the traffic can be monitored for malicious content. Some access point manufacturers actually include a basic NIDS support capability in their products. You can also use dedicated wireless access points, connected to the NIDS as sensors to monitor wireless activity.

The nice folks at NIST have written a very informative report (see Special Publication No. 800-94) that discusses the different types of intrusion detection – and intrusion prevention – technologies and how they work. It is well written, and provides many insights into IDS/IPS usage and capabilities. Using this technology with wireless LANs is a bit more complicated, but the NIST document does an admirable job of explaining the issues.

You might want to think about a HIDS, NIDS and/or IDPS system as a burglar alarm system for your networks and critical systems. Its job is to watch for known threats, suspicious behavior and actual attacks. Part of the ability of this technology to detect malware is based on having up-to-date "signatures" just like your regular virus scanning tools. An IDS (or IDPS) system must be kept updated as new threats and attack methods are identified. The sophisticated systems monitor for anomalies in user behavior and also look back over operational history and log files to see if new patterns of user or system behavior are occurring. Some vendors have developed quite advanced analysis modules to try to detect aberrant behavior in its earliest phases (i.e., when a threat agent is poking at your defenses performing reconnaissance) in order to provide enough warning to forestall a successful attack.

However, just like a burglar alarm, it does no good if the IDS sounds the alert – by sending a message – but no one is listening. One of the burdens of using this technology is the need to have knowledgeable personnel routinely review alerts and alarms generated by the IDS to see if they are 'false positives' or actual threat indications that should initiate a protective/defensive response. Just as with a physical security alarm system, an IDS is liable to generate occasional false alarms.

There are a number of vendors and products on the market that provide NIDS/HIDS capabilities. They can look over your organizational infrastructure and make suggestions about how best to apply their products. If your IT organization has the internal expertise you can put one together yourself, often at a surprisingly low cost. One of the best network-based intrusion detection packages available today is an open source tool called SNORT –yes, like the noise a pig makes, and it even uses a stylized pig in the logo!). Using a standard high-end PC loaded with one of the secure LINUX operating system distributions such as SE Linux – Security Enhanced and SNORT you can create a powerful and flexible NIDS; plus, the SNORT user community offers a lot of free or low-cost support and a constant flow of rule updates that address new threats.

If you want to create your own HIDs you don't have the same level of open source options. There are some open source packages that provide some of the functionality I have discussed, such as 'Tripwire' for monitoring for file modifications. There are also vendors that are focusing on developing HIDS 'agent' software for selected industrial control systems. Because of its powerful detection and prevention capabilities HIDS technology is more complicated in many ways, and has more integration issues, than does NIDS, but that will be the subject matter for a future column... ***Tim***.

ABOUT THE AUTHOR

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

Guest Editorial

Outage Management: A Long and Winding Road

By Edmund P. Finamore, P.E., President, Valutech Solutions

Edmund P. Finamore

Not so long ago a utility's outage management system consisted of three main components: a call center, a radio dispatcher and a trouble ticket system – and for some utilities that's still the case. While many of us might long for a return to those days, I think we can all agree that era is gone forever. In today's world, a restive public will no longer tolerate even brief power interruptions limiting access to their electric appliances, creature comfort systems and other electric-powered conveniences. As a result, the growing importance of outage management as a utility discipline, with its need for increasingly more sophisticated outage response tools, has been a long and winding road that is finally coming to fruition with the availability of sophisticated new OMS systems.

During those early days when central computer systems were still rather unsophisticated, security standards were modest (at best) and Sarbanes-Oxley didn't exist, implementation of advanced outage management systems with their outage filtering mechanisms and predictive restoration capabilities seemed very far off. Of course, a compliant customer base back then was not nearly so demanding that their local utilities provide good – and reliable – service.

Those old legacy systems went about as far as their limited data processing speeds and database management capabilities would take them, which was not very far. In-house IT staffs built many of the early outage management systems, which were not much more than simple work order systems with a hard printout, in the days before commercial-off-the-shelf (COTS) software and outside system integration specialists became the dominant players in the field. These days, computer speeds and advanced outage tracking capabilities, when coupled with the outage data coming from SCADA and smart metering systems, can process and filter large amounts of data and provide responders with much greater clarity when assessing the overall outage landscape than ever before.

Given the increasing emphasis placed by DOE, FERC, NERC and state regulatory commissions on improving network reliability, the market for sophisticated outage management systems is booming. Regulatory agencies have encouraged utilities to tighten reliability standards while at the same time implementing measures to moderate and shift peak system demand. DOE's Smart Grid Investment Grant Program, for example, has provided matching funds for grid enhancements that focus on load shifting, while also improving reliability as measured by traditional power interruption metrics such as CAIDI, SAIFI and SAIDI. As electric utilities continue to focus on demand response for moderation of peak loads, regulatory emphasis on improving network reliability is expected to continue to increase.

Capital Budget Impact

One unfortunate characteristic of outage management systems is their necessary reliance on external data sources for success. Traditional sources of outage information such as SCADA, and of course the aforementioned utility call center, don't provide the outage granularity needed to achieve quantum improvements in outage response. More recently, utilities have begun installing capital-draining network AMI systems with advanced metering functions that can provide power quality data including outage and low voltage alarms from each customer's meter.

As these new AMI systems come on line and begin to fulfill their long-time promise, utilities will increasingly leverage the outage reporting capabilities of these systems through integration with OMS. For most utilities, however, this next adventure is yet to come as they attempt to recover from the huge impact of AMI implementation on their beleaguered capital budgets.

System Integration Can Be Challenging and Costly

Interestingly, for all of the industry hoopla over the new advanced IT infrastructures and interfaces such as Service Oriented Architecture and Enterprise Service Bus that use Web Services APIs, XML and SOAP protocols, relatively few fully integrated AMI and outage management systems that use these methods actually exist in the field today. Implementing these new IT architectures typically requires taking a holistic view of a utility's entire IT infrastructure and assessing its impact on all enterprise level applications, including the utility CIS system. This transition can be a protracted and very costly endeavor.

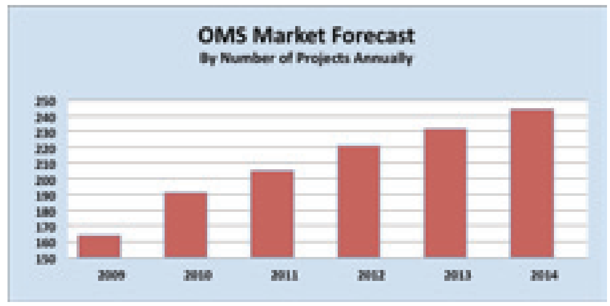
And further complicating the utility enterprise application environment is the recent introduction of meter data management (MDM) systems to process large volumes of AMI data. MDM systems are designed to manage extensive amounts of meter data coming from their AMI systems and to broker events and alarms to other utility applications. Synchronization of OMS with the CIS, GIS and MDM systems is difficult to achieve, and typically requires utilities to engage outside system integrators at substantial cost. While standard OMS interfaces such as MultiSpeak do exist for some AMI to OMS interfaces, the complexities and real-time requirements of these system interfaces frequently require the use of vendor specific APIs created specifically for this purpose.

OMS Outlook is Strong

It is therefore not surprising that the market outlook for OMS systems is positive and sales are trending upward as an improving economy generates additional utility dollars for capital projects. The utility market research firm InfoNetrix has conducted some interesting research in this area, and as the chart below illustrates, more than $85 million is expected to be spent on OMS annually by 2014.

SOURCE: VISTA-Smart Grid Horizons Report; InfoNetrix LLC, New Orleans, Louisiana USA

And as I mentioned, required improvements in distribution network reliability are increasingly driving utility decision-making, and implementation of OMS is becoming essential for many utilities.



SOURCE: VISTA-Smart Grid Horizons Report; InfoNetrix LLC, New Orleans, Louisiana USA

According to the data provided by InfoNetrix, the outlook for OMS expenditures is expected to be quite positive over the next 5-6 years, even though its winding road has often been quite bumpy. Once considered an optional or lower priority application, InfoNetrix has gained some interesting insights into the actual state of play for these systems, as summarized below.

- OMS will continue to enjoy strong growth, and is driven by NERC reliability guidelines, which have now become mandatory.
- Other regulatory bodies have begun placing emphasis on reliability improvements, which should produce continuing OMS market growth.
- OMS systems are becoming more sophisticated and will become more extensively integrated into utility distribution management systems.
- OMS systems will also become more integrated with utility work management and asset management systems in the future, which will increase their market value and integration costs.

Moreover, the study forecasts significant gains in the number of OMS projects during this same period, as implementation expands into the municipal and rural electric markets. The following chart reveals an upward trend in the sheer number OMS projects that are projected to take place during the same period:

Outage Management: A Long and Winding Road

It is interesting to see that OMS implementation is no longer limited to just the larger investor owned utilities. InfoNetrix also forecasts significant growth in the number of smaller municipal and rural electric utilities that will install OMS systems, although these systems will likely be somewhat less sophisticated with fewer features and interfaces. According to InfoNetrix:

- The number of OMS projects will continue to increase at a steady pace over the next few years as utilities increasingly address reliability issues.
- Municipal and rural electric utilities will become more active concerning OMS deployment, but with more limited functionality, interfaces and cost.
- A smaller percentage of OMS projects will come from the investor owned utility sector as IOUs struggle to complete their AMI projects. Many of the integration issues discussed previously will come into play and could potentially drive up the cost of the more sophisticated installations.
- Over time, OMS projects will become increasingly more integrated with work management, field force management and asset management systems as they share data and pursue operating efficiencies

Older OMS systems will continue to operate and provide utilities with a base level of functionality that was adequate for the simpler times of the past. However, among the important issues going forward will be whether or not these older systems can be successfully integrated with newer AMI and MDM systems and whether the transition to newer IT architectures will force them into retirement.

The Road For OMS

The long and winding road of OMS development and implementation is surely not what the Beatles were describing with their hit song in 1970, even though many older trouble ticket systems do go back that far. I think even Paul McCartney would agree that writing a tune for the lengthy OMS story line would be a difficult task at best, since OMS is far from reaching the end of its road. Indeed, after nearly 40 years of implementation, we are finding that for OMS, the road is just beginning.

ABOUT THE AUTHOR

Ed Finamore is President of Valutech Solutions, Inc., a management consulting firm specializing in AMI systems and the Smart Grid. With over 35 years of utility automation experience, Mr. Finamore is a widely acknowledged industry expert and authority on smart metering systems and has authored many articles about various aspects of the Smart Grid. He received Electrical Engineering and MBA degrees from the University of Pittsburgh and is a Licensed Professional Engineer in the Commonwealth of Pennsylvania.

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