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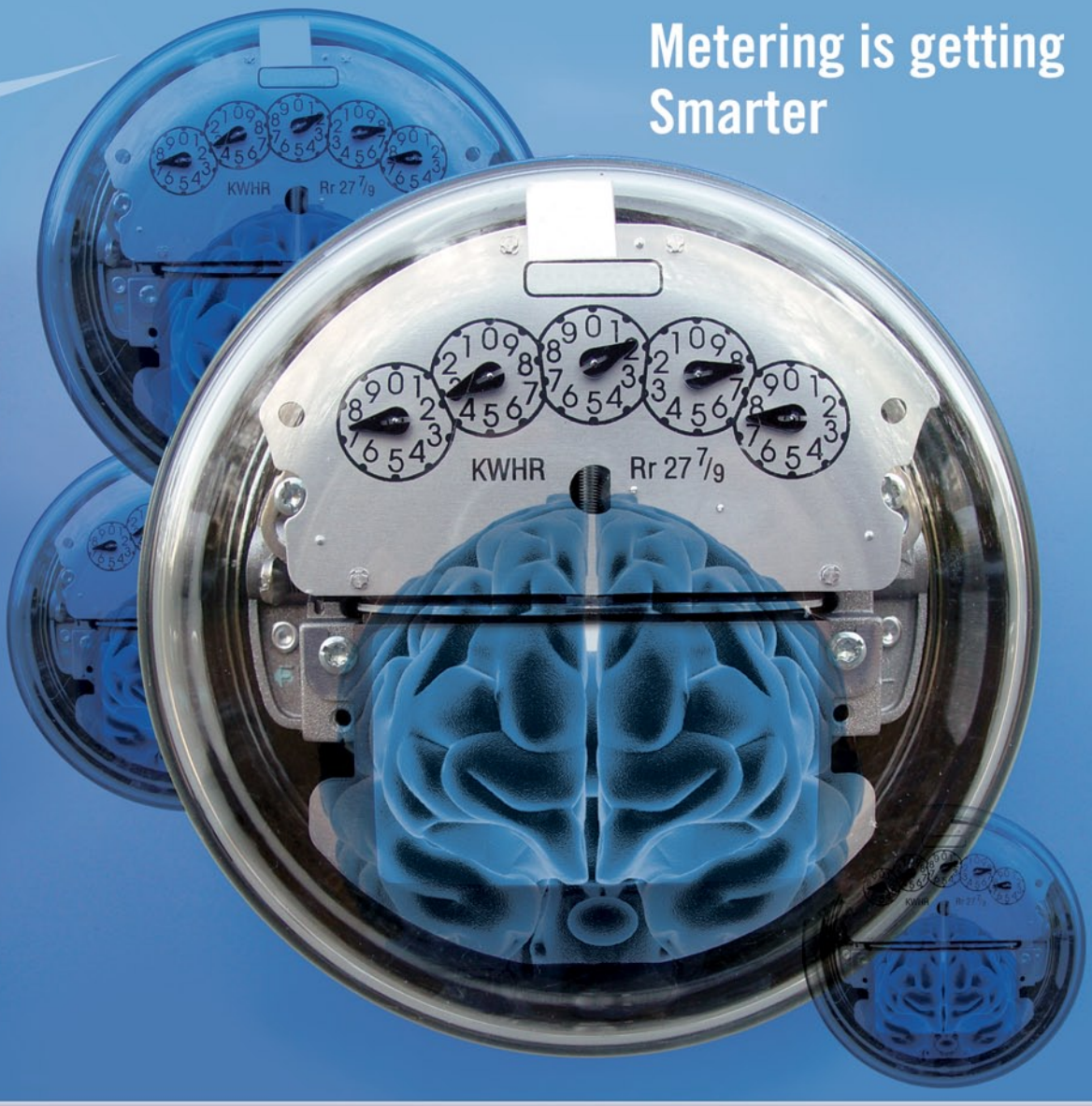
Metering is getting Smarter



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3M Expands RFID Marker System for Underground Facilities

LONDON, Ont. — 3M is expanding the product family for RFID-enabled electronic utility markers by releasing 3M™ Near-Surface Marker and 3M ™ Full-Range Marker to address the broad range of permanent marking needs.

3M RFID markers locate specific underground facilities precisely and efficiently. The new markers are designed for both shallow markings two feet (60 centimetres) below the surface, and deeply-buried applications at eight feet (2.4 metres). Both are available as active (programmable) or passive (non-programmable).

"As the complexity and value of underground services continues to grow, there is an increasing need for accurate and reliable database mapping at deeper levels," said Jim McManus, Business Manager, Track and Trace solutions. "3M's new RFID markers facilitate increased productivity and effectively prevent damage to vital lines beneath the surface."

When placing underground pipelines or cables, durable, anti-freeze fluid-filled marker balls containing an electronic tuned circuit and electronic marker RFID (tags) are buried above key underground elements. These markers use the new RFID technology (custom RFID chip inside), programmable in the field, which stores specific details of that marking tailored to a specific company's needs. RFID tag information ranges from marker identification number and installer's name to the purpose and date of installation.

GPS coordinates indicate where the elements are, making companies safer and more productive. The hand-held 3M Dynatel 2200M-ID Series Receiver, pinpoints the location of these markers by using industry established utility marker frequencies, even when diverse utility markers are adjacent to one another. The RFID tags are located with a utility-specific radio frequency signal and respond to the locator with the programmed details.

3M's RFID marker system is the first of its kind in the industry and is designed to outlast the life of the facility it marks. This system is useful in many underground facilities and is currently used by a leading telecommunications company in Canada.

For more information about the 3M RFID marker system visit www.3M.com/dynatel.

GE Multilin launches the most advanced line distance protection relay in the market.

MARKHAM, Ontario, Canada, — GE Multilin unveiled today the D90^{Plus}, the most advanced protection system in the market, a single-platform solution for the protection of MV to EHV transmission lines. The D90^{Plus} is a sub-cycle distance relay with true convergence of multiple functions, including advanced automation and control, high accuracy digital fault recording, comprehensive communications and extensive local HMI capabilities. True convergence of functions eliminates the need to have multiple stand-alone devices resulting in significant savings in the installation, commissioning, maintenance and life-time costs.

With its innovative dual algorithms the D90^{Plus} provides a high degree of sensitivity and

selectivity for all types of faults, delivering secure and reliable sub-cycle operation for a wide variety of system conditions to improve power system network stability. The dedicated user programmable high-speed protection logic allows users to customize independent protection and control schemes to meet specific application requirements.

The powerful D90^{Plus} incorporates an advanced automation engine with a powerful user programmable logic that provides millisecond deterministic execution rates, irrespective of program size. The independent programming logic engine (FlexLogic™) features math, Boolean and control functions which may be used for advanced load shedding, load restoration and dynamic volt/var control schemes. By including this advanced automation engine, costs associated with auxiliary components and wiring can be minimized or even avoided. When combined with its communication capabilities, D90^{Plus} automation features far surpass what is found in the average line protection relay.

With a dedicated fast and slow scan disturbance recorder, the D90^{Plus} eliminates the need for dedicated stand-alone recorders. With a high accuracy, 128 samples/cycle multichannel analogue and digital recorder, virtually all power system transients and long term events can be recorded and viewed. Utilizing GE Multilin's EnerVista™ software suite, operators have single-click retrieval to view and analyze the transient waveforms and event records.

The D90^{Plus} includes comprehensive communications features for remote data and engineering access. Supporting standard utility protocols including IEC61850, DNP3.0, IEC60870-5-104 and Modbus TCP/IP, the D90^{Plus} is flexible to use and easy to integrate into new and existing infrastructures. The availability of three independently configurable Ethernet ports provides the means to create fault tolerant communication architectures in an easy, cost-effective manner eliminating the need for intermediate communication hardware.

The new D90^{Plus} provides extensive local HMI capabilities featuring a default annunciator and an optional HMI. The digital annunciator allows users to customize alarms, eliminating the need for separate annunciators in the relay panel. The annunciator panel also provides detailed self-test messages eliminating the need to look at manuals to understand cryptic messages. The intuitive and easy to navigate HMI provides comprehensive display and control functions, delivering comprehensive data visualization including metering, sequence of events, fault reports and I/O status. The HMI also features pre-programmed single-line diagrams for bay monitoring and control.

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City of Anaheim Deploys Advanced Control Systems Outage Management System in Support of Smart Grid Strategy

ATLANTA, GA – Advanced Control Systems (ACS), a leading global provider of smart grid solutions to the electric power industry, announced today that the City of Anaheim Public Utilities (Anaheim) has completed the production deployment of the ACS PRISM Real-Time outage management system (OMS) to increase reliability and deliver improved electric service to its citizens.

ACS developed PRISM Real-Time OMS as a tightly integrated component of its comprehensive suite of smart grid solutions for electric power utilities. Anaheim operates its OMS from the same real-time database that supports its ACS SCADA, substation, and feeder automation systems – resulting in lower data and system maintenance costs compared to traditional multi-vendor solutions. With its OMS, Anaheim has achieved faster outage prediction and restoration, streamlined switching operations, enhanced system visualization and improved safety for field crews and citizens.

ACS has demonstrated that its integrated PRISM smart grid platform for OMS, DMS and automation can sustain over 750 system events per second during storms, heat waves, and other events that stress electrical distribution systems.

Anaheim serves approximately 110,000 customers throughout a 50-square mile area, with a peak system demand of more than 580 megawatts. It operates ten 69 KV/12 KV distribution substations (with 17 69 KV transmission lines) and 105 12 KV distribution substations. A 50 MW combustion turbine generator is deployed for peak conditions.

ACS president David Moore remarked, "Anaheim has been a valued ACS customer for over a decade. With the production go-live of PRISM Real-Time OMS, we are pleased to showcase Anaheim as one of our most progressive customers and as an early adopter of our integrated smart grid approach."

In addition to OMS, Anaheim has deployed ACS solutions for SCADA, substation and feeder automation, interactive voice response for crew call out, and enterprise business intelligence, including real-time tracking and reporting of IEEE 1366 reliability indices.

ACS marketing director Gary Ockwell concluded, "Utilities seek cost-effective solutions that provide fast payback in the key areas of customer service and delivery reliability. This continues to be the driving force behind the smart grid innovations that ACS is bringing to the market."

For more information, visit *www.acsatlanta.com*.

OEFC Selects Rodan as Meter Services Provider (MSP)

Mississauga, ON, Canada – Ontario Electricity Financial Corporation (OEFC), the Province's administrator of legacy power purchase contracts with various non-utility generators (NUGs), has awarded Rodan Energy and Metering Solutions Inc. (Rodan) a five year contract to provide metering services for about seventy (70) NUGs. Rodan has previously provided services to OEFC as MSP for twenty-seven (27) IESO Connected NUGs. Under the new contract Rodan assumes an additional responsibility for up to forty-three (43) Embedded NUGs that are connected to the respective distribution systems of various local utilities.

Through a competitive Request for Proposal process, Rodan has once again demonstrated a core competency as a MSP. With the expanded scope of this mandate, Rodan will be taking an active role in monitoring the integrity of Ontario's electricity system. "Distributed generation is becoming an increasingly important component of the power supply mix in Ontario." stated Paul Grod, President of Rodan Energy. "We are pleased to be selected by the OEFC as we continue to build on our MSP expertise with a full range of metering, engineering and power system solutions by providing a full generator-to-wires solution to power producers."

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Hydro One's Smart Meter Project wins North American award

TORONTO – Hydro One announced today its Smart Meter Project has been selected as winner of a Utility Planning Network's (UPN) 2007 Metering Award.

"I am extremely proud of the employees of Hydro One and their efforts in support of the Province's Smart Meter Initiative," said Laura Formusa, Hydro One President and CEO (acting). "To date, Hydro One has installed more than 160,000 smart meters and is on track to having 240,000 installed by the end of 2007."

Hydro One was selected for the 2007 Metering Award in the category of Automated Meter Reading (AMR) Initiative – North American Municipal or Cooperative. AMR, or smart metering as it is often referred to, is the term used to describe all of the hardware, software, and connectivity required for a fully functioning smart metering system. Hydro One's Smart Meter team, including its main vendor partners Capgemini and Trilliant Networks, is deploying a smart meter system which will be able to adapt and work with new technologies as they evolve such as internet addressed in-home energy conservation devices (e.g., two-way real time monitors and automated thermostats). In addition, once fully operational, the system will enhance power restoration efforts by alerting the company to power outages in real time.

Hydro One's Smart Meter Project was selected for the award by an international panel of judges. This year, entries were received from around the globe including Europe, South America, Australia, the United States, and Canada. Hydro One's entry covered all aspects of the project from meter deployment (automation, communication, customer service), through to planned time-of-use conversion, and the company's strategic vision to leverage the communication and IT infrastructure in the future to increase efficiency. Former winners have included Niagara Mohawk, Consolidated Edison, and Southern California Edison.

UPN and its related Advanced Metering Peer Group is a global organization that enables utilities worldwide to share business best practices related to business case development, implementation, and operation of advanced metering systems. See www.metering-awards.com for more information on the awardsprogram and the Global AMI Utility Peer Group.

Hydro One delivers electricity safely, reliably and responsibly to homes and businesses across the province of Ontario and owns and operates Ontario's 29,000 kilometre high-voltage transmission network that delivers electricity to large industrial customers and municipal utilities, and a 122,000 kilometre low-voltage distribution system that serves about 1.3 million end-use customers and smaller municipal utilities in the province. Hydro One is wholly owned by the Province of Ontario.

Managing the Floodgates: Comprehensive Meter Data Management

As Advanced Metering Infrastructure (AMI) deployments occur across virtually every service territory, the volume and availability of Smart Metering data grows exponentially. Distribution Companies are charged with not only monitoring system health, but also ensuring accuracy of data passed to the CIS.

As a leading Application Service Provider (ASP) across North America, Olameter is assisting organizations manage the large amounts of available data by providing a proven and scalable MDR solution. Backed by Olameter's extensive industry experience and EnergyICT's flexible EIServer® application, this ASP offering allows utilities of any size to manage data effectively. This MDR serves as the centre of Olameter's AMI information technology offering, as depicted.

A wide array of technology is currently being deployed, and each organization is mandating unique interval and volume requirements. Therefore, it is recognized that any MDR system utilized must be flexible to import various head-end formats, allow perpetual load-balanced import schedules, and allow import of varying interval lengths. Olameter's offering fulfils these requirements and also imports all available non-metered data, allowing measurements of energy, demand and other metrological information to be available for Billing/CIS purposes.

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As data is imported from AMI data collection system, validation, estimation, and editing processes are initiated automatically within the MDR based on system triggers. The MDR incorporates the ability to validate meter data against rules that have been set by the client; data is clearly versioned for auditing purposes, in the event of billing inquiries or disputes.

Olameter's MDR is easily integrated with various standard and legacy systems. The MDR supports both direct external access via the thin client or market-based data exchanges commonly found in deregulated markets. Load aggregation and virtual meters are standard functions, and EIServer has an optional billing engine that can be used for complex billing functions, as well as built-in code table functionality that supports Time-of-Use (TOU) structures. EIServer also supports settlement processes in deregulated energy environments.

Experience has shown that the combination of historic consumption data with external data generates a far more accurate forecast. Therefore, a forecasting module allows clients to forecast interval-based profiles that are not limited in time. The forecasting module is capable of forecasting day-ahead, week-ahead, month-ahead, and year-ahead profiles, and can deal with multiple inputs.

These features, combined with additional system monitoring and reporting tools, offered in an ASP environment allow for comprehensive, reliable data management during pilot projects and into full-deployment stages. For more information, email *info@olameter.com*.

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By Michael A. Marullo, Contributing Editor

Communications: Steak or Spam?

Besides providing a good reason to regularly reflect on the state of the industry, writing this column provides a way for me to also give something back by talking candidly about some of the things that might otherwise be left unsaid. As an editorial voice I can be frank and sometimes perhaps even a little irreverent when necessary to make a point about something important… this is one of those times.

This column is about a trend that I don't like very much, and I suspect many of you may not like either, but so far almost nothing I've seen has addressed this topic head-on. That topic is Communications Etiquette. I'm really beginning to think that maintaining a civil and professional posture in the course of routine business communications – whether involving written or verbal interactions – may be fading into history as the appropriate and widely practiced code of conduct.

Please, leave a message after the beep…

Perhaps this problem started with answering machines. Remember the first time around with answer machines, those nifty gadgets that everyone hated because they just seemed so terribly impersonal? At the time, most people felt that the very concept of using an answering machine was at best an insult and at worst, a de-humanizing indignity. After all, why would any self-respecting person talk to a machine?

Your call is very important to me…

But then, along came voicemail with that polite invitation to leave a message so that your call – which was, of course, VERY important to the receiving party – could be returned at the earliest possible opportunity.

A lot of us liked voicemail at first because it seemed so friendly and beneficial. Heck, when a call came in and you were on the phone, at least the caller wouldn't just get a busy signal or have to endure an endless ring that would never be answered if you were away from your phone. Instead, you – via an audio alter ego – could tell the caller you were on the phone, out sick, away on vacation or whatever, saving incalculable time and resources.

Coincidentally, that was probably around the time we first heard the term "right sizing." In its early stages, right sizing meant your secretary got fired, since a human answering machine was suddenly deemed unnecessary. (Gee, who knew that all secretaries did was answer the phone and take messages?)

But then, something really bad happened: The now 'secretary-less' workers realized that they had to become even more efficient. Who had time to keep track of all those voicemail messages, especially without a secretary? Why not just use voicemail "like" a secretary – as a call screener? Not a bad idea initially, but not quite the same thing either.

Whereas your secretary could say, "Bob's in a meeting right now, but he'll be available in about 30 minutes if you'd like to call back then," all the voicemail system can manage is: "Please, leave a message." Obviously, the voicemail system couldn't stop you on your way out of the conference room the way your secretary could, so if you forgot to check your messages, ignored them or simply received them too late, you'd miss things. (Remember, your secretary could usually figure out what was important and what wasn't, apparently by just answering the phone! Pretty amazing, huh?)

Once the initial infatuation wore off, voicemail became pretty tedious for most of us. But then someone decided we needed additional assistance. And, living in the Information Age, what better to relieve the distress caused by overloaded voicemail than – you guessed it – more information!

Enter, the Automated Attendant:

Ostensibly intended to help us, automated attendants – those annoying pre-recorded message menus we're all forced to navigate when all we really want is to ask somebody (ideally, a real person) a simple question – increasingly confound even the most skilled and patient among us. Some menus will take you a dozen or more levels deep and are changed regularly, allegedly to make the navigation process easier. Indeed, there are probably few if any among us that have not encountered the dreaded: "Please note that our menus have changed…" message, just when you think you've finally got the navigation figured out.

But instead of helping, what automated attendants really do is take us another step away from human interaction and add another layer of an all too pervasive do-it-yourself mentality, quickly turning our attempts to obtain information into a daily battle of man versus machine. While this might all sound sort of hypocritical coming from an automation person, the point here is that when we automate, the goal should be to enhance the human element… not eradicate it. But let me get to the really prickly part of the problem.

Until recently, most business people still managed to communicate effectively, using complete sentences and responding in a timely manner. Even with the inherent time limitations of what we now call "snail-mail," costly long-distance telephone charges, the absence of video conferencing and other such amenities, we conducted business and went about our assigned duties with arguably far less stress and strain than we do today.

Moreover, as we have succumbed to relentless demands to do more with less, we've also been rapidly losing our ability to communicate with one another in a reasonable and mutually respectful way, the latter being something I believe is important to all of us as human beings. Ironically, with all of the technology designed to help us operate and interact more efficiently and more effectively, our ability to really communicate on a personal and professional level has become the ultimate casualty.

Even attempts to convey valuable information, a great opportunity or other types of beneficial communications routinely go unanswered for days, weeks or longer if ever acknowledged at all. The universal excuse is that people are just too busy.

And trying to communicate via email is worse yet. Most people (and/or their companies) have some type of spam filter that weeds out not only the unrelenting firestorm of email trash from Web-based drugstores, companies hawking pirated software and international financial scammers, but also snags any attachments and rejects anything that even looks like it might not be requested material.

Why? Because we're all buried in so much junk mail that we can barely function! Yet problematic as it is, in my humble opinion, the greater evil is that even legitimate correspondence has been subordinated to 'junk' status. In our zeal to achieve efficiency, we have managed to throw the baby out with the bathwater, as my mother used to say.

One of the latest innovations in communications is IM (instant messaging). Short of an intravenous device, sending someone an IM, which may appear on any of a variety of mobile electronic devices, is the most recent weapon in the battle for human interaction. The trouble with IM is that messages tend to be cryptic, highly abbreviated and often unintelligible. After undergoing several levels of conversion, translation and other mangling before being displayed on a 2-inch screen, messages are often 'read' while the recipient is driving down the freeway at 70MPH. Sadly, this is what passes for effective, efficient communications these days.

I could carry on endlessly about how people react when someone won't take the time to respond to a call or email, or how it's almost impossible to have a meaningful conversation with anyone that lasts more than a minute or two, but I won't. Just consider this a simple request on behalf of everyone who wants to communicate: Make an effort to recognize the difference between efficiency and neglect by not treating all communications equally, whether voicemail, email or any other medium.

Hey, we're all busy, all of our time is valuable and we all have a full plate. But the next time you feel overwhelmed by phone calls and email, try to remember that when it comes to communications there's a difference between steak and spam – a distinction worth noting.

- Mike

Behind the Byline

Mike Marullo has been active in the automation, controls and instrumentation field for more than 35 years and is a widely published author of numerous technical articles, industry directories and market research reports. An independent consultant since 1984, he is co-founder and Director of Research & Consulting for InfoNetrix LLC, a New Orleans-based market intelligence firm focused on Utility Automation and IT markets. Inquiries or comments about this column may be directed to Mike at MAM@InfoNetrix.com.

The Environment, Advanced Metering, and the Business Process Revolution

By Guerry Waters, Vice President, Industry Strategy and Marketing
Oracle Utilities Global Business Unit

Advanced metering is capturing attention at utilities around the globe. Initially, industry analysts saw it as a way to restrain environmental damage from electricity consumption. Now, it's helping to break down utility departmental barriers and facilitate cross-organizational business processes.

Environmental issues are Topic Number One at utility gatherings. Industry leaders around the world are re-examining the link between energy, emissions, and global warming. Do utilities have an obligation to help slow damage from energy use? If so, how can they best fulfill that obligation?

Most utility leaders accept that obligation. But there is little consensus on the best response.

Clearly, yesterday's environmental programs—discounts on compact fluorescent light bulbs, exhortations on insulation—were less than effective in staving off potentially catastrophic environmental change. But if those programs are not the answer, what is? Should utilities revise pricing structures? Should they hope markets alter consumption habits? Should they re-imagine the obligation to serve as an obligation to conserve?

Such questions are helping to surface new environmental proposals. Advanced metering is one of the most compelling.

The Rise of Advanced Metering

The road to advanced metering starts more than 20 years ago, with automated meter reading (AMR). Designed to replace human meter readers, AMR uses radio, satellite, or wire signals to read consumption totals remotely. Most utilities, however, found AMR costs exceeded meter-reader salaries and benefits. AMR landed on the sidelines.

But not everywhere. One usage area proved cost-beneficial. Industrial and commercial firms with energy managers found significant advantages in combining AMR with interval metering.

Interval metering (or "complex billing") combines remote meter reading with meters that record consumption in intervals of an hour or less. [1]Utilities use them to charge different prices for energy during different time periods. Interval meters do not require reprogramming when prices change. Software processing accommodates those changes, leaving the meter to record only consumption.

Interval metering permits commercial and industrial firms to accept utility incentives to cut consumption during high-demand periods. That means utilities can serve more customers with fewer lines.

Interval metering is also a popular substitute for utilities' previous approach to supply or transmission constraints: "all or nothing" interruptible supply programs. With interval metering, firms can reduce energy consumption without cutting it off completely. They thus ensure "soft landings" for industrial processes that cannot be simply turned off midstream. And utilities can readily track—and penalize—customers that do not live up to their contractual agreements.

As interval metering spread, users discovered unanticipated bonuses:

- Lower energy supply costs. In liberalized energy markets, companies use interval metering to aid participation in competitive markets.
- Better equipment performance. Interval metering provides valuable information about equipment efficiency and potential problems. It permits companies to substitute preventive maintenance for repair or replacement. Production lines experience fewer unanticipated shutdowns.
- Consumption reductions. Detailed analyses of interval data point out ways to reduce both expensive peak consumption and total energy use.

This last bonus—conservation—has clear environmental implications. When utilities can pinpoint the times and places where demand is dropping, lower demand means less generation. That translates directly to fewer emissions.

It's only natural, then, that those seeking emissions reductions ask: Given the same tools, might all customers—l business and residential alike—achieve similar use reductions?

The jury is still out on the answer. But the potential is clear.

Data Ownership

The potential environmental benefit of interval metering is so compelling that utilities have moved beyond concepts. Some are now planning ways to implement mass-market interval metering.

Planners almost immediately confront a significant question. How should we handle the massive increase in data that accompanies interval metering? The size of that increase is significant. In the residential arena, for instance, hour-long intervals would replace today's typical 12 annual consumption numbers per residential customer with 8,760. That's a 730-fold increase.

What hardware and software can handle that volume? And what new procedures will ensure that data processing flows smoothly?

The answers to those questions spring in part from current utility organization. In most utilities today, billing departments "own" metering data. That has worked well because today's metering data is largely irrelevant outside billing. Few other departments need the monthly consumption totals that characterize traditional residential billing.

[1]Technically, interval metering does not require remote reading. In practice, however, data storage at the meter level generally proves less cost effective than sending readings serially to a central location.

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Interval meter reads, however, can be useful to many departments. They can provide information on load size and shape. That helps reduce generation and supply portfolio costs. The reads are even more valuable when combined with metering features like two-way communication between meter and utility, voltage monitoring, and "last gasp" messages that signal outages.

These new data provide departments outside billing with an information treasure trove. But few departments want to play second fiddle to a billing department inclined to put its own needs first. Even if billing hardware and software can technically handle the increased data volume, can Billing handle a significant increase in interdepartmental data demands? Will it respond to other departments' needs for real-time data transfer?

Some utilities may answer yes. Most are skeptical. They fear that if billing takes on major additional functions, bill production—and the associated utility cash flow—will falter.

Separating Metering and Billing

Enter a new concept: meter data management (MDM). The MDM is a new, independent application dedicated to gathering and storing meter data. It can also perform the preliminary processing required for different departments and programs. Most important, MDM gives all units equal access to commonly held meter data resources.

MDM's independent service function may be further refined through the addition of a meter data warehouse. In situations where both exist, the MDM typically manages real-time, transactional processing while the warehouse handles data extraction, reporting, and analytical processing.

Separating the MDM from the billing solution has clear advantages. It maintains bill production efficiency while providing even-handed data access to all departments. The separation also permits a utility to add security to meter communications and data without complicating customer access to bill payment and analysis websites.

Challenging Departmental and IT Structure

MDM is, for most utilities, a new type of application. It shatters the typical utility IT model in which each department "owns" its own set of applications.

MDM treats every department as its "owner." It thus forces departments to work together. If MDM is to serve all equally efficiently, then the various stakeholders must share information. They must agree to application configurations that serve all needs optimally.

This process of information sharing is proving eye-opening to departmental heads. Suddenly, sharp minds have the knowledge and tools to propose better, more efficient program administration.

In other words, MDM is becoming an avenue for rethinking utility business processes independent of existing departmental boundaries. It is the first major utility silo-breaking application.

Expanding the Concept

Independent applications serving multiple departments are not, of course, the only software approach to breaking down departmental barriers. Application integration has long played a role, though its expense has prevented utilities from developing a full complement of data interchanges that could better pierce departmental barriers.

Far less successful were attempts to develop composite applications, popular a few years ago. Composite applications, consisting of individually addressed functional modules, were touted as a major breakthrough to cross-organizational business processing. Advocates foresaw a significantly lower total cost of ownership.

Software developers soon realized, however, that multiple applications calling on each other's functions more or less randomly were unlikely to facilitate cross-organizational business flow. A more probable result was computing resource chaos.

MDM avoids that chaos while also moving beyond simple software integration. It did not originate as a conceptual computing innovation. Its origins were strictly pragmatic—the need to handle efficiently a potentially huge increase in data volume. It has evolved, however, into something much larger.

MDM, by providing both unique and common resources to multiple applications, has the potential to advance the quest for multi-departmental business process orchestration. If it succeeds in this role—as it very likely will—other functions may quickly follow suit. Scheduling, for instance, might be pulled out of asset management, field management, and appointment setting and consolidated into a single instance that serves multiple departments.

Multi-departmental applications like MDM, owned cooperatively among departments rather than individually, could thus be the "missing link" to facilitate the smooth flow of business processes across the organization. They could prove a process orchestration concept that increases the efficiency with which utilities serve all stakeholders.

About the Author

Guerry Waters joined SPL WorldGroup—now Oracle Utilities Global Business Unit—in 2000. Previous positions include Vice President of Energy Information Strategy at META Group and CTO and Director of Technology Strategy and Engineering at Southern Company. He focuses on customer-related, enterprise-wide IT strategies and business processes.

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Bob Gilligan, General Manager, GE Energy

The 2007 Automation/IT Leadership Series

By Michael A. Marullo, Automation/IT Editor

GE Energy

Bob Gilligan, General Manager

Bob Gilligan is a 17-year veteran of one of the largest and most successful industrial enterprises in the world. Bob runs GE Energy's T&D business – a significant component of the $19 billion GE Energy business that is by itself, several times the size of all but a few of its industry counterparts. Moreover, GE brings to bear a depth and breadth of products and services that encompass virtually every aspect of the utility automation/IT business. However, despite the size and diversity of GE's portfolio, like any other company, there are things that they do better than others and things that are best done by others. In preparing for this interview, I thought it might be interesting to further examine that dichotomy with Bob to see how and where he feels GE best fits into the market – and where they don't – both now and in the future. – Ed.]

EET&D: For nearly a century, GE has been primarily a product-centric supplier of transformers, capacitors, protective relays, UHF/VHF radios and meters. Over the past decade, however, the company has transitioned into a mainstream force in the systems portion of practically every major automation/IT solution set, much of which has been the result of strategic acquisitions. What major objectives have you set for GE-Energy over the next few years, and how do you intend to get there?

Gilligan: Our overall strategy has been to bring best-of-breed building blocks together to form comprehensive automation/IT solutions for our customers that embrace both established and evolving standards, new technologies and support intelligent grid initiatives.

Our view is that it will take a more integrated open systems approach to address the difficult challenges facing utilities today. Development and conformance to industry standards, a holistic systems approach, and the wherewithal to implement and maintain solutions over an extended time frame will be key to success. We think that GE is uniquely positioned to meet this need.

With this vision and strategy in mind, GE embarked on a series of acquisitions to develop its portfolio of solutions. One of our earliest acquisitions – the former Harris Controls in Melbourne, Florida – was at the beginning of our strategic automation/IT solutions initiative, which put us squarely into the SCADA/EMS business. That was followed by the acquisition of Smallworld Systems in 2001, and Syprotech and Ascada in 2002. The Smallworld acquisition put us literally "on the map" in the GIS field.

GE has invested heavily in the integration and expansion of these businesses as a parallel to the integration that has been steadily evolving within those markets. Today, we have blended a tightly coupled business model with open systems architecture, creating strong business and technical support across our platforms for our customers.

Our overarching goal is to directly provide the essential automation/IT building blocks at both the platform and device levels. We augment that foundation with specific domain expertise complemented by a network of strategic suppliers and partners that allow GE to provide a holistic approach to the challenges utilities are facing – and will face in the coming years.

EET&D: There is little doubt that the electric utility industry is entering a new era creating quite a lot of discussion regarding the use and application of technology to help address the multitude of challenges and problems associated with power delivery. Clearly, GE has vast technological research and development capabilities at its disposal. How do you see the role of technology as it relates to solving T&D problems while also advancing your objectives in electric utility automation/IT markets?

Gilligan: Unlike common practice in the 1970s, 1980s and most of the 1990s, utility needs today are far less likely to be dictated by technology trends than by business processes, KPIs (key performance indicators) and financial drivers. This is about solution driven technology. What this means is that we have to get our engineers out of the laboratory and into the field with our customers. This "outside-in" orientation is helping us to ensure that the products, systems and services we develop are justifiable from the customer's economic and practical standpoint. The result is an increase in our R&D spending due to greater certainty in an economic return.

EET&D: Although very large companies like GE are often said to be less nimble as their smaller counterparts, some aspects of the business require resources that would be virtually impossible for less robust companies to muster. Do you agree with that notion?

Gilligan: A key strength of GE is our ability to scale up and sustain investment over a long period. We do this through internal resource commitments and the development of partnerships and strategic relationships with third parties that have complementary skill sets and offerings that GE does not provide directly.

It's clear that there will be great challenges involved in transitioning the current grid to a more modern design with the ability to operate in ways not originally intended or accommodated by the present design. Many different types of solutions and technologies will be required, some of which GE already has, some of which we will develop and some of which will be provided by a network of partners and strategic suppliers.

Our network of partners and strategic suppliers is a key asset for GE, both in terms of the breadth of our solution portfolio as well as the size of our geographic footprint. GE is a global company with a pervasive presence, but we obviously can't be everywhere. Our partner network helps us to extend our local presence and project ourselves forward into new geographies faster than we could on our own.

EET&D: Quite a lot has been written and said about the two big issues that seem to be

foremost in everybody's mind right now – Aging Workforce and Declining Infrastructure – so I don't want to belabor them, but I think our readers would like to hear your thoughts on how the industry can address these looming and most formidable problems.

Gilligan: The common denominator between the aging workforce and declining infrastructure is the need for knowledge capture and the ability to act on it. This should be the output from the automation/IT infrastructure we put in place. The aging resource challenge is to capture the knowledge of the utilities' retiring human assets and convert it to defined processes, tasks and decision tools. This must get memorialized in the automation/IT systems, enabling the utility to share that knowledge more quickly than can be done manually today, thus, improving efficiency.

Similarly, with aging infrastructure there is an increasing need to monitor the health of that equipment on a more real-time basis. Again, more information capture and associated decision tools are required to allow utilities to act quickly to protect those assets. Moreover, the aging workforce and declining infrastructure are driving investments in grid intelligence. The brute force method of throwing people and assets at the problem of reliable grid operation is too expensive. Automation/IT infrastructure investment represents an opportunity for greatly improved operations productivity and asset life extension, helping to address these critical challenges.

EET&D: Let's switch over to the regulatory side of the equation. The Energy Policy Act of 2005 has been lauded by some as providing definitive direction for a variety of much needed initiatives including infrastructure improvement, energy conservation and reliability enhancements, just to name a few of the many areas it touches upon. However, it has also been roundly criticized as containing little more than vague suggestions, hyperbole and innuendo. What's your take on this broad and encompassing piece of legislation; is it actually having – or will it ever have – any tangible impact on any of those vitally important areas?

Gilligan: EPACT is a typical legislative measure. It's not the panacea that some had envisioned, but it does significantly raise the level of awareness and comprehension of the present and future landscape of our energy needs and challenges. That broad-based awareness is a vital first step toward making tangible progress.

Overall, we see an overwhelmingly positive effect from the heightened awareness brought about by EPACT that we must now turn into definitive solutions, much of which will necessarily require automation/IT components.

EET&D: Dealing with energy issues is by no means unique to the United States or North America. As a global company whose involvement in these issues transcends both geographic and political boundaries, what can we learn from other countries or regions that may be applicable to the domestic automation/IT marketplace?

Gilligan: A good example is the UK where there has been a greater emphasis on putting the technology to work to solve business needs. According to a 2003 study by Cambridge Energy Research Associates (CERA), operators in the UK have much higher capital employment efficiency than in the US, which results in measurable operational and performance improvements. Notably, a great deal of the reason for that improvement is the extensive use of fully integrated automation/IT throughout their major utility enterprises. I think the UK's experience is a very important case because it establishes precedence and a set of proven metrics for justifying the use of automation.

EET&D: I've always felt that in many, if not most cases, the utility automation/IT business has been driven more by suppliers than by the utilities themselves. But today, we've arguably reached a crossroads where utilities need to take the lead on some of the sweeping changes that are needed before any real progress can be made toward what are arguably the most aggressive goals this industry has seen in a long time, perhaps ever. How would you characterize the roles and responsibilities of suppliers and utilities in today's market?

Gilligan: The key component in this equation is risk and the sharing of that risk, and as we all know, utilities are inherently risk averse, especially where the adoption of new technology is involved. The traditional practice of piloting new technology and concepts is no longer working because what needs to be piloted now is not just a particular product or technology, but rather an entire business model.

Clearly, creating a new business model requires a much bigger investment that is not adequately addressed and that cannot be properly resolved in a timely or economic fashion using the typical RFP process. It needs to be addressed on a partnership basis with both the risks and rewards being shared at every stage of the project between the owner and supplier(s).

With the myriad of new technologies that will be deployed in connection with smart metering, demand response and intelligent grid initiatives, utilities will likely be creating new forms of revenue production that have not been there in the past. The specifics will increasingly depend on new and/or enhanced levels of service that go well beyond the present operating norms, which must be married with new reward mechanisms that are developed in concert with the local and national regulatory bodies.

EET&D: Speaking of economics, very few projects of any substance get approved without an economic justification. Yet not very much has been said about the economics of Intelligent Grid initiatives; so far, it's been mostly about reliability. How do you put dollars and cents on such a bold set of expectations?

Gilligan: The intelligent grid is not just about reliability; it's also about energy efficiency (resource utilization), operational efficiency (revolving around optimal use of non-electrical assets; i.e., people) and environmental impact (reducing the amount of greenhouse emissions, etc. and minimizing the impact of the energy generation, transmission and distribution have on the environment). These are the four main pillars upon which grid infrastructure improvements will be based in order to achieve better overall grid management, reliability and efficiency.

Among other things, this will allow the optimization of the current infrastructure to deliver more real power and to become a more effective highway for managing loads across the grid. In the end, it's really all about resource utilization and resource efficiency, so the thrust of the intelligent grid initiatives must be focused on those real-world objectives where the economic benefits are fairly easy to see and justify rather than on the economics of any given individual project of the traditional definition.

In other words, simply justifying an AMR, GIS or SCADA project isn't going to get us where we need to be. The process has to be taken to a much higher level across the entire utility enterprise that is fundamentally supported by – rather than justified by – the individual automation/IT initiatives.

EET&D: So much of the Intelligent Grid discussion revolves around things like AMR/AMI/MDM and related Smart Metering initiatives. With so much interoperability among automation/IT platforms already in place, how does the Intelligent Grid fit into the broader scheme of things?

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Gilligan: Exchanging data across disparate platforms is a huge and very expensive challenge. This is where the use of open standards is very important. GE has made a corporate commitment and substantial investments in nurturing and supporting standardization initiatives. As such, we make an effort to embrace and implement these standards across our products and services whenever and wherever possible.

Much of what needs to be accomplished from an automation/IT perspective within a utility enterprise involves data validation, whether it's ensuring accurate data for a complex transaction, analyzing a security issue or providing operational data for regulatory compliance.

In all of these cases, as well as many others, open standards are needed to help accelerate and improve that validation process. Bringing the right data – say from a bank of smart devices – onto an enterprise bus that provides access to the data in an appropriate format and subset required for compliance and/or decision-making is absolutely crucial to supporting specific business processes. And, as we evolve toward a more robust and flexible grid, those processes are likely to become even more diverse, more demanding and more complex.

EET&D: We've already talked about the head-end and "middleware" of the automation/IT business. There is a body of research that suggests a surge in the transition from traditional instrumentation to IEDs (Intelligent Electronic Devices) is building. What do you see happening at the sensor level and how does that fit (or not) with Intelligent Grid initiatives?

Gilligan: Of course the trend toward increased usage of IEDs will continue as will the standards that allow this vital field data to be accessed. However, despite the considerable intelligence implicit in these devices, we feel that utilities will probably lean toward inexpensive sensors that deliver critical data and transmit that data easily and efficiently.

There are already huge amounts of what many refer to as "non-operational data" in the field that the utilities cannot afford to access for reasons ranging from insufficient communications bandwidth to a lack of the necessary analytical tools and staff to make proper use of it. Thus, in many cases, a large cache of data – valuable though it may be – is often not as valuable as a few pieces of critical data that can be easily accessed.

EET&D: Utilities are just now rebounding from what amounts to a 20-year moratorium on T&D investments. Now, we're talking about undertaking sweeping changes to the grid that while certainly long overdue, will require billions in investment before any tangible results can be realized across a long list of glowing expectations. Is it realistic to think that utilities will move forward fast enough to see measurable progress toward those lofty goals within a reasonable period of time?

Gilligan: As we've discussed, many forces have aligned to drive the change: stronger energy policy; aging workforce; stressed equipment infrastructure. T&D has been under-invested for 20 years in comparison to new generation capacity… so the time has come for change. There will be leaders and followers in this change process. I think it's very realistic to expect near–term, large-scale demonstration projects of broad investments in utility automation and IT infrastructure to demonstrate and quantify real operational benefits. In addition, economics will force utilities to demand more targeted technology solutions for asset life extension and workforce productivity with a view to how these application specific solutions will fit into their longer-term vision for the more holistic systems architecture.

EET&D: I'd like to wrap up by getting your general views about the future of electric power delivery in North America. While I think everyone would agree that our dependency on electricity is going to keep on growing, huge challenges loom. As such, there are divergent theories about how we can actually meet that growth outlook while preserving reliability, security and the environment. What insights can you share with us about the kinds of changes we might expect over the next three to five years, particularly from an automation/IT perspective?

Gilligan: Well, Mike, that's an interesting question… I think the scope of the challenge will certainly require that utilities, suppliers, and regulators all think and act differently. New business models will emerge with more equitable risk sharing among the key stakeholders. As utilities move into the information era, the pace of change for technology will continue to accelerate. This will require adoption of more standard - as opposed to custom engineered - solutions, that can be more effectively and efficiently maintained and migrated by the suppliers than by the utilities themselves. Domain knowledge will become critical to understanding and effectively impacting the critical issues facing the utilities. Long-term supplier relationships will grow in importance to reduce the risk of "stranded" applications. GE is well positioned for the long term to lead and succeed in this environment.

Elster's milestone highlights the company's world leading position in two-way RF AMI deployments

Elster, the world's leading manufacturer and supplier of highly accurate, high quality, integrated metering and utilization solutions, announced that it has shipped its millionth EnergyAxis® System smart meter. The EnergyAxis System is an advanced metering infrastructure (AMI) that uses powerful state-of-the-art two-way communications to manage installed devices and retrieve related metering information. It is the most widely deployed AMI system in North America featuring a true two-way RF network—a technology of choice among utility companies.

"We are pleased with the unprecedented performance and growth of the EnergyAxis System since its launch in 2003," remarked Mark Munday, president and CEO of Elster Electricity. "As the largest, two-way, RF deployment of true AMI applications in the world, the system enables customers to retrieve consumption, time-of-use, and interval data from residential, commercial, and industrial accounts on a daily basis."

The milestone meter was shipped to Salt River Project (SRP), the third largest public power utility in the United States and the largest supplier of electricity and water to the greater Phoenix, Arizona area.

"We are excited to be the recipient of Elster's millionth EnergyAxis System smart meter," remarked John Soethe, manager of revenue cycle services for SRP. "The EnergyAxis System has worked well for us and we continue to deploy REX® meters in areas of high customer turnover, in areas of concern for employee safety, and for access issues. Operating efficiencies realized in the back office and in the field make this technology very attractive."

System installations span the globe with deployments in North America, Central America, the Caribbean, Australia and New Zealand ranging from high density metropolitan environments to lightly populated areas including remote rural villages in Alaska. A high concentration of EnergyAxis System smart meters are deployed throughout Ontario, Canada to meet the requirements of the Government of Ontario's Smart Metering Initiative.

About Elster

Elster Electricity is a leading provider of electricity metering products and services throughout the world. Located in Raleigh, North Carolina, Elster Electricity offers integrated, cost-effective solutions including smart meters, communication solutions and metering automation systems for residential, commercial and industrial applications. Elster Electricity serves customers through a global sales force.

Elster Integrated Solutions (EIS) is a leading provider of AMR and AMI systems and solutions. EIS helps utilities improve revenue cycle services, customer service, delivery reliability and workforce utilization as well as implement demand response and conservation programs and reduce non-technical losses. Core to EIS solutions is the use of intelligent mobile and fixed network communications.

Elster Group is the world's leading manufacturer and supplier of highly accurate, high quality, integrated metering and utilization solutions to the gas, electricity and water industries. In addition, through its subsidiary Ipsen International, it is the leading global manufacturer of high level thermo-chemical treatment equipment. The group has over 8,500 staff, operations in 38 countries and serves over 115 markets around the world. Elster's high quality products and systems reflect the wealth of knowledge and experience gained from over 170 years of dedication to measuring precious resources and energy.

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Elster ships one millionth AMI system smart meter

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Flexible and adaptable for future applications and communications technologies, the EnergyAxis System enables customers to retrieve consumption, time-of-use, and interval data from residential, commercial, and industrial accounts on a daily basis. Its open and interoperable, standards-based architecture enables utilities to improve revenue cycle services, customer service, delivery reliability and workforce utilization, reduce non-technical losses, as well as implement demand response and conservation programs.

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Utilities can find this combination in Sensus Metering Systems' FlexNet tower-based fixed network system and the Sensus iCon smart meter.

How can electric utilities leverage the most from the AMI system and remain a savvy consumer? Two Sensus officials offer thoughts on the electric utility metering industry and how an efficient data collection system can propel customer service and operational efficiency. Offering commentary is Sensus' Doug McCall, director of AMI marketing, and Arlin Rummel, director of strategic accounts.

Doug McCall

Arlin Rummel

What should an electric utility consider when searching for an efficient metering solution?

Doug: Efficiency in an AMI system may be realized if the system includes three basic concepts: simplicity, reliability and flexibility. The AMI system should have a simple network design, because minimal infrastructure means minimal ways for the system to break. It should have robust range and transmitter power and a proven disaster recovery capability. And, it should be able to service a growing community. Make sure the system is engineered to exceed specifications, and that it has been field tested and proven.

Arlin: Energy providers should demand a solution that allows utilization of state of the art communication technologies while maintaining billing functions. Sensus developed the iCon line of meters to integrate new communication technology with proven reliability and accuracy.

There is a lot of buzz regarding the type of radio frequency an AMI system operates from. Why?

Doug: Systems are built to last at least 20 years, and these are expensive endeavors. The type of radio frequency used affects the risk of stable transmissions. Unlicensed or shared transmissions will increase the risk of interference. How can a 20 year business case be built on a communication medium that may not be viable in the future? Licensed frequencies are secure and powerful, which decreases the chances for faulty transmissions. A primary-use licensed RF system provides a guaranteed right-of-way for clear transmission of AMI data for the life expectancy of the system. This license is issued by the Federal Communications Commission, which is legally obligated to pursue any frequency interference. Sensus has a primary use license for its FlexNet communications system.

Arlin: A primary use license also allows a utility up to two watts of power to transmit. Other secondary use licenses, and shared / unlicensed systems operate at less than half that power. Higher signal strength extends the range of transmissions, which increases the RF coverage area, which minimizes the number of tower-based collectors needed, which lowers infrastructure cost.

Can you summarize any emerging trends in the electricity metering industry?

Doug: Electricity meters are rapidly gaining more and more functionality. A proper AMI system should include both the flexibility and bandwidth to capture and utilize the functionality that exists today, as well as the functionality that will come in the future, all without having to replace infrastructure.

Arlin: At Sensus, the gap between energy information requirements and meter capabilities led us to create a two-way metering gateway system that would serve as a platform for gathering data and information from electric meters, as well as providing information to customers. Today's electricity meters provide a source of knowledge for energy management, demand side response, outage management, asset management, rate development, power quality analysis, customer relationship management and revenue protection.

AMI systems are now more than a data collection system. What features does FlexNet have that can enhance the utility's slate of services?

Doug: The FlexNet infrastructure can incorporate a utility's transmission and distribution assets. I see the trend to integrate applications on both the line side and load side of the electric meter with AMI systems for added value and benefit to the utility. These applications include distribution automation and demand side response operating on a home area network. FlexNet was designed with these value added services in mind. We do not have to go back and fit a square peg in a round hole to incorporate such applications – the architecture already exists.

Arlin: With the FlexNet integrated display, our iCon residential meter is an efficient and reliable AMI-ready electric meter. The iCon meter endpoint is a resource with Home Area Network applications for utility-to-customer communications. The meter combines AMI communications and meter display on one board, making it more reliable and efficient than AMI meters with expansion boards. Also, with the antenna residing on the display board, signal strength and overall RF performance are enhanced. The open architecture and two-board design allow the iCon meter compatibility with multiple AMI communication technologies.

Does the AMI system represent the best in technology?

Doug: Improved technology plays a large role in steering Sensus' AMI features and functionality. Two immediate examples are the remote disconnect applications and memory storage at the meter. And technology is helping companies do business better. These benefits are helping to lower costs, which gives decision-makers a tangible basis for justifying the AMI system.

Why the iCon meter?

Arlin: The Sensus iCon meter was developed with customer input and has technology that is designed for effective integration under the AMI application. The iCon meter delivers reliable and accurate performance at the most extreme operating conditions, and has a smart communications interface with an open protocol message structure to deliver precise, error-free information. With its remote firmware upload, the iCon meter minimizes risk and is a platform for long-term use that will not be outdated as industry AMI requirements evolve.

You advocate a joint system of FlexNet and the iCon meter. Why?

Doug: The team of FlexNet and iCon is field proven for reliable operation in any operating environment. This team presents solutions to contribute the benefits utilities require for positive operations and excellent customer service. The iCon meter was designed specifically for AMI and the FlexNet system can take advantage of every feature the iCon meter has to offer.

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Cellnet+Hunt: Merger brings together industry leading solution providers for advanced metering and smart-grid communications

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The new company, Cellnet+Hunt, brings together the experience gained from deploying 20 million advanced metering endpoints, and the resources and support of more than 700 employees.

"The integration will provide our customers the widest range of proven and cost effective solutions in the market," said David Slump, Chief Executive Officer." Each company has a tradition of technology and service that, when combined, will benefit a broader customer base well into the future."

An 18-year veteran of the power industry, Slump is uniquely prepared to direct the integration and growth of the new organization. He previously held leadership positions with GE, ABB, and Commonwealth Edison. At GE Energy, Slump served as General Manager of global marketing for the $19 billion provider of power generation and energy delivery technologies. At ABB, he held several US and European executive positions including president of the U.S. utilities division.

Regarding his leadership of the merger, Slump said that service to existing customers is priority number one for the newly combined Cellnet+Hunt team. The new executive team is blending the unique strengths of both companies to offer the most competitive solution available.

From a technology perspective, the merger brings together PLC, mobile RF, RF mesh, and fixed-network RF technologies for electric, water and gas meters, as well as solutions for DA and SCADA applications. The combined solution set offers utilities a single source for complete smart-grid technology, including the software and service needed to realize maximum system ROI.

"We now have the capacity to offer more technology options and service models than anyone in the industry," said Gary High, Vice President of Sales and Marketing. "This creates real choice for utilities seeking a full-service provider."

Cellnet+Hunt is based in Atlanta, GA, and maintains its Pequot Lakes, MN office as a center of excellence for cooperative utility systems. The company is part of the Bayard Group of companies, a global enterprise specializing in energy efficiency technologies.

About Cellnet+Hunt

- Combines two industry-leading companies into one organization focused on advanced communications for AMR, AMI, DA and SCADA applications.
- More than 20 million metering endpoints deployed or under contract.
- Largest fixed-network customer base in advanced metering industry.
- Technology portfolio includes one-way and two-way, PLC, RF and RF mesh communications options.
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Reading meters efficiently, accurately

by Kelly Prentice

When American Electric Power (AEP) made the switch to automated meter reading (AMR) in 2004, its team noticed the benefits right away.

"The more we could use a mobile van and reduce sending someone to a site, the more we saved on operations and maintenance over time," says Jack Carr, AEP manager of meter revenue engineering.

By using mobile devices to retrieve wireless radio frequency signals from each meter, AEP technicians could also measure peak demand in a more timely way.

However, as AMR modules were installed on the meters, electric utilities realized one problem: The majority of electricity AMR systems in the United States use one-way communication technology. Though a technician could remotely retrieve billing data from the meter, he or she could not remotely reset the meter in order to determine the next peak demand. Despite the benefits of AMR, technicians still had to go to each meter to manually press the "demand reset" button.

To solve the problem, other utilities implemented a calendar on the meter, which was programmed with the billing cycle to reset on a specific date. But this type of "cycle-sensitive" meter missed the mark for AEP.

"To manage a calendar is quite messy for utilities, especially because we often change billing cycles," Carr says.

So, AEP's team turned to GE—one of their major meter suppliers—to help them develop a "cycle insensitive" demand meter solution. "We needed a one-way AMR demand solution that was not dependent on the calendar," Carr says.

Using a proprietary algorithm, GE created a new way to obtain peak demand information from the AMR modules that displays proper demand values each month, regardless of the billing cycle. Its "cycle insensitive" meter solution calculates demand at the end of each day. The module continues to record 35 daily demands, each day dropping the oldest and adding the most recent data.

"This allows you to put a calendar in the meter that doesn't reset on a specific date," Carr says. "It gives us more flexibility in the way our meters calculate demand values."

More peaks per cycle

The solution also provides the ability to capture more than one peak demand value from each meter. The first peak is set to about 21 business days, the average number of business days between cycle reads. The second peak is typically 18 or 19 business days—used when the billing period is shortened, either because the meter was read late last month or early the current month.

AEP has adapted billing and IT systems in preparation for implementing the metering solution. As AEP integrates it with its existing AMR modules, Carr will evaluate the cost-benefit of retrieving this additional data from the meters. He says it should help AEP keep track of momentary outages, along with eliminating misreads and estimated bills.

"Because metering is the cash register of the company," Carr says, "we want to make certain we measure it correctly and avoid estimating a bill. This helps us maintain a high level of customer satisfaction."

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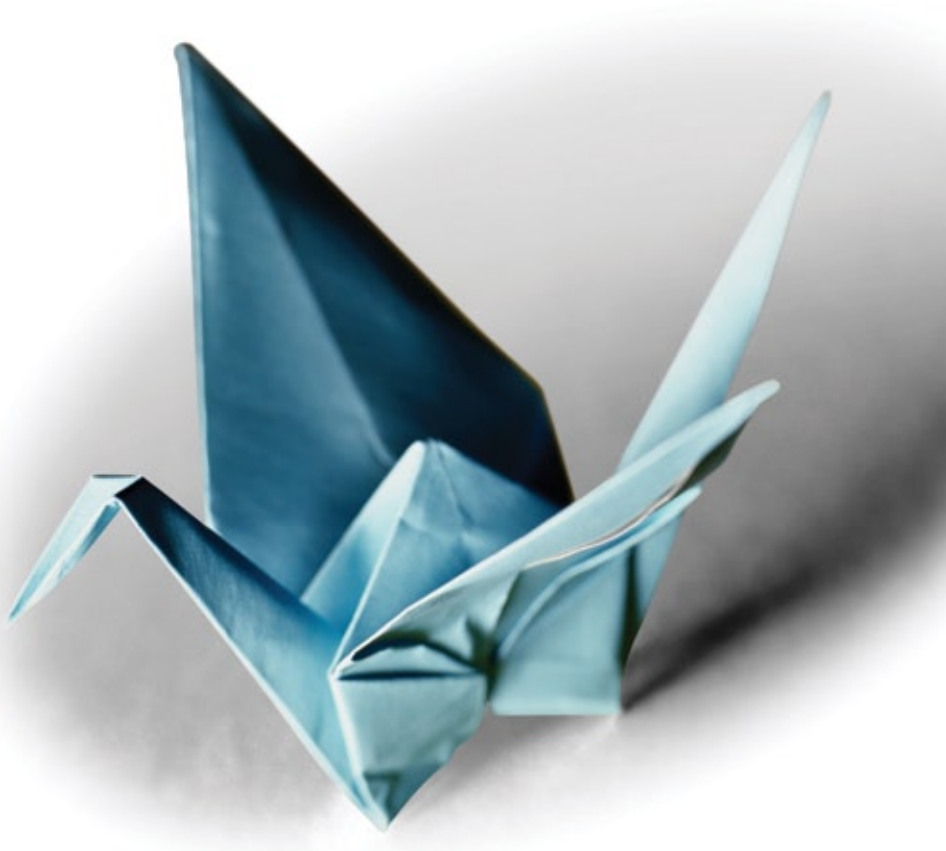


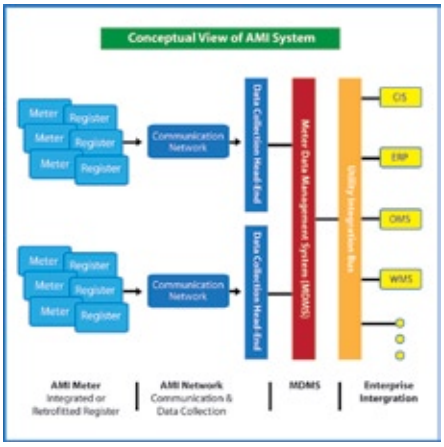
imagination at work

Asset Management for AMI

By Jeff Evans, consultant and project manager, Enspiria Solutions, Inc.

Asset Management for Advanced Metering Infrastructure

An Advanced Metering Infrastructure (AMI) system is comprised of a large volume of assets which include meters, modules, network communications infrastructure, and may also include remote disconnect/reconnect switches and demand response/load management (DR) system components (in-home displays, programmable/controllable thermostats, load control devices). When a utility implements AMI, they suddenly have millions of additional assets to manage. Many utilities' workforces are not fully equipped to manage these new AMI assets.



Separating Metering and Billing

Advanced Metering Infrastructure promises transformational benefits across the utility enterprise. AMI is a pivotal information source that, used effectively, can drive efficiencies and benefits such as improved network and service reliability, increased revenue, increased profitability, and enhanced customer satisfaction.

As a simple example, AMI identifies meter failures via automated notification, allowing them to be addressed immediately rather than waiting for the next manual meter reading. Avoiding this delay minimizes the risk of lost or unbilled revenue and reduces the possibility of customer dissatisfaction with failed equipment.

Achieving and sustaining AMI benefits requires not only prudent planning of the AMI system but also proper management of the AMI system and system assets. Utilities can expect to spend multiple orders of magnitude more for an AMI system than they were spending on typical metering. With significantly longer payback periods, maximizing return on AMI investments is critical to ensuring achievement of the business case.

The discipline of asset management is designed to optimize asset use and manage all maintenance efforts involved in making assets as reliable, accurate, and efficient as possible. Utilities lacking an AMI asset management system run the risk of incurring significant additional, unexpected expense due to failed or poorly maintained equipment. For example, failure to proactively maintain the communications infrastructure of an AMI system may lead to unexpected failures and loss of communications to meters. If this occurs during a power outage, interruption duration and the cost of restoration will increase due to the lack of AMI-based information about the extent of the outage. If loss of communication occurs during a billing window, customers may receive estimated bills – a leading cause of customer dissatisfaction. This dissatisfaction often results in additional effort to investigate and resolve billing complaints.

How do AMI Assets Differ?

Utilities can't manage their AMI system assets in the same way they manage their legacy meter assets, for three key reasons:

- Remote nature of automated meters
- Sophisticated communications infrastructure
- Enterprise-wide AMI system

Asset management of traditional meters is based on periodic testing and meter reader visits to the meter. AMI assets typically don't require a physical visit by utility personnel. AMI meter readings are obtained remotely, disconnect/reconnect actions are executed remotely, and DR devices are controlled remotely. Rather than physical interaction with these devices, utilities rely on automated communications and data analysis to manage all of these assets. The availability of automated on-event and on-demand diagnostic data from an AMI system provides the opportunity for efficient and effective meter asset management.

AMI systems utilize a sophisticated communications infrastructure. Power line carrier, broadband over power line, and radio frequency communications require unique and often voluminous communications assets. Utilities have successfully managed communications infrastructure – mobile and

LAN/WAN communications being an example. But AMI systems are more complex than typical communications infrastructure because they incorporate meters, additional network devices such as concentrators, relays, and/or take-out points, and head end data collection systems in addition to the communications infrastructure. AMI systems can also include in-premise, or in-home devices such as displays, smart thermostats, and load control equipment.

Unlike legacy meters, AMI is an integrated enterprise-wide system, and must be managed as such. Integration of AMI data through a meter data management system (MDMS) and a utility integration bus facilitateseasy communication of the data and information with utility applications such as billing, customer care, and system planning. AMI meter information (diagnostics and alarms) can be integrated with workforce management systems and included on work orders to allow field personnel to more efficiently address premise-related issues. Power outage and restoration information supplements customer reports of outages to enhance the efficiency of a utility outage management system. Supplemental data helps target the portions of a service territory impacted by the outage and the failed equipment causing the outage. Integrating AMI information into your geographic information system (GIS) allows for more efficient asset location and dispatch of field personnel.

Create a comprehensive asset management plan

A detailed, clearly-articulated plan must be developed that provides the framework for both proactive and reactive asset management. The asset management plan should clearly identify:

- Assets targeted for management. Assets range in volume and location depending on the AMI technology selected. While meters and modules are obvious elements to an AMI system, the communications infrastructure, demand side management devices, and operating system hardware and software can vary. The locations of these assets must be captured and maintained – a change for many utilities as metering location information isn't typically tracked in a GIS system. Premise address information isn't always an accurate or available method of locating assets.

- Measures necessary to assess the health of assets. AMI components have an expected operating life that can change depending on use and operation. Measures such as failed communications or number of remote disconnect operations completed can indicate the health of an asset and identify when a corrective action must occur.

- Proactive and reactive actions necessary to maintain the assets. Identification of health indices requiring action must be identified and the appropriate responses developed and documented. Proactive inspections of communications infrastructure ensure continued, efficient operation. Removal and analysis of failed meter assets can identify a meter population requiring immediate attention.

- Data necessary to calculate asset health measures. The AMI system isn't the only source of AMI asset health information. Completed field work orders, such as meter investigations or revenue protection investigations, augment health indices. Distribution system reconfigurations or facility upgrades may change the locations of assets or the timeliness of asset management activity. Data from all appropriate sources must be utilized when assessing asset health.

- Repository to capture the data. The data from multiple sources must be made available in a single location to the organizations responsible for asset management.

- Tools and reports necessary to implement action. The data obtained from an AMI system must be converted into intelligent, actionable information.

- Organizations responsible for the assets. The appropriate organization must be identified and charged with the task of managing the AMI assets.

The asset management plan must be agreed to by all impacted organizations and communicated across the company.

Make the right organization responsible

Meter shop personnel have traditionally been tasked with managing meter assets. Sample and periodic testing, failure analysis and shop testing, and the resolution of failed meters are largely established processes. AMI systems, however, incorporate smart meters, home area networks, and the associated communications infrastructure. AMI systems are more complex than traditional metering and require a different skill set to manage and maintain. The ability of an organization to address all AMI assets, not just meters, is essential to successful AMI system asset management.

What organization should be responsible for managing this complex system? When implementing AMI, utilities typically build an organization responsible solely for the AMI system. This responsibility includes day-to-day operations, system maintenance, data management, and exception resolution. The AMI Team ensures that the AMI system operates as expected and delivers the data promised. This AMI Team should also be tasked with AMI asset management.

The AMI Team should include personnel whose expertise is distinct to each component of technology. Information Technology personnel are needed to manage the AMI Technology and MDMS operating systems. Meter personnel are needed to manage the electric meters and gas and water modules. Telecommunications personnel ensure that the communications infrastructure operates as expected. An exception management team resolves communications failures and data discrepancies and ensures resolution of billing issues.

The AMI Team will work with the appropriate field personnel to implement the asset management plan for their areas of expertise.

Acquire the necessary data

The next step is to identify what data should be tracked for each system, to obtain the proactive and reactive data needed to determine asset management actions.

Collecting data about their AMI assets allows utilities to understand the assets and their performance. Device diagnostics, device operations, and age help identify, predict and determine the field activity necessary to maintain devices. Tracking and management of firmware versions is necessary to ensure that the latest functionality and diagnostics are available from each device. Service order histories provide valuable intelligence about the asset management history and help identify potential asset issues. Without this overall view of AMI assets – from diagnostic information on each asset to appropriate asset service histories – utilities will not be able to make adequately informed asset decisions.

Data is both static and dynamic. Warranty and service level agreement (SLA) contract provisions result in key performance indicators (KPIs) that can be used to measure performance quantitatively. When implementing an AMI system, utilities should demand SLAs and warranty provisions to protect their AMI investment. In support of this, utilities must demand the data necessary to measure and track against these SLAs and associated KPIs.

While utilities are adept at capturing and storing data, utilities are not adept at converting multiple pieces of data into the information necessary to make asset related decisions. Utilities should consider the implementation of a new set of tools to assist with this effort.

Implement tools to turn data into information

To make intelligent, efficient, effective decisions regarding AMI system assets, utilities need tools that capture data from multiple sources and run analytics against that data. These analytics help facilitate the proactive and reactive management of assets.

Most utilities utilize some sort of asset management tool – typically intended for transmission and distribution assets. These existing asset management systems have not been designed to track and manage the distinct assets of an AMI system.

Most AMI technology operating systems (data collection head-ends) incorporate the tools to manage the communications infrastructure assets. Head-ends provide access to information about meters and communications infrastructure, but typically lack the detailed device and network management capabilities that are typically found in more mature industries like IT and data communications equipment management. Additional functionality is available from some of the commercial MDMS vendors, and some AMI systems are compatible with enterprise network management systems such as HP OpenView, IBM Tivoli, and CA UniCenter. In most cases these systems provide only reactive information and

AMI Asset	Description	Asset Management Issues/Considerations
Data collection head-ends (AMI technology operating systems)	• Head-ends control the operation of the AMI communications infrastructure and smart meters and provide access to information from and about these assets	• Typically lack meter and network communications device asset management capabilities
AMI smart meters	• Meters capable of communication via an AMI communications infrastructure to the data collection head-end	• The potential for different meter and communications module firmware versions drives the need for firmware asset management
Remote disconnect/reconnect switches	• A remotely operated load control switch integrated within the electric meter or within a collar installed between the meter and the meter fitting	• Introduction of a new asset that is subject to damage from attempts to restore disconnected service • Requires tracking and management of device health to ensure continued operation
Home area networks (HAN)	• A network of control and communications devices communicating wirelessly within the home through the electric meter to the utility	• Multiple evolving communications standards • Lack of universal standards and interoperability
Demand response/load management (DR) system components	• In-premise/in-home devices such as displays, programmable/controllable thermostats, and load control equipment that communicate via the HAN with the utility	• Ownership of some components can vary between utility and customer; utilities must track ownership to ensure that appropriate maintenance of utility assets occurs
Meter data management system (MDMS)	• A system that ensures collection and translation of meter data into information that can be used by the various utility applications such as billing, outage management, and GIS.	• Can capture asset information about the various components of an AMI system. • Affects warranty tracking, service order management, and system diagnostics.
Network communications infrastructure devices	• Devices that facilitate communication between the meter and the utility • Comprised of single or multiple layers of radio frequency, power line carrier, public, and private communications methodologies	• Preventative maintenance required to ensure that communications continue within expected frequencies and latencies

rely on periodic preventative maintenance in lieu of proactive or reliability-centered maintenance until systematic heuristics and the software to execute them is developed.

For example, most utilities rely on scheduled replacement of meter and module batteries to reduce the likelihood of failed operation due to a dead battery. These scheduled replacements often occur before the battery has reached the end of its useful life. The use of battery alarms captured by the head-end to determine the right time to replace batteries allows for the optimal use of this asset.

Over the 15-20 year life of an AMI system, a percentage of the meter and module population will fail and require replacement. New meters and modules typically incorporate the latest meter and communications module firmware. Unless all meters are upgraded with the latest versions of firmware as they become available, the meter population will contain varying versions of firmware. No AMI technology vendor currently has a solution for tracking and managing the multiple versions of firmware. Firmware configuration management has the potential to become a significant issue and should be a critical component of asset management.

Meter data management systems are designed to be the central hub for data obtained from the AMI system. The MDMS can capture asset information about the various components of an AMI system. An MDMS tracks the data about each component and affects warranty tracking, service order management, and system diagnostics.

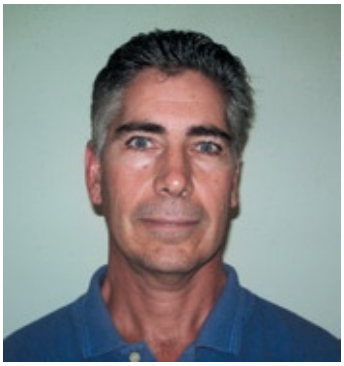
An MDMS can also consider multiple sources of data when analyzing the need to manage an asset. A meter that experiences multiple momentary indicators (blink counts) may be an indicator of a meter issue. But it could also be an indicator of something else. The MDMS can utilize data from an outage management system to rule out reliability issues and data from a service order management system to rule out utility work already in progress at the premise. The MDMS can also review the history of the meter to identify potential trends in meter issues. The incorporation of multiple data sources into the MDMS analytics helps validate that a meter issue is really a meter issue and improve the efficiency of the work force managing assets.

Conclusion

Utilities are placing more and more emphasis on proactively managing non-AMI assets now – utilities should use this groundswell to promote the management of AMI system assets. AMI asset management improves the efficient and cost-effective operation of an AMI system and allows utilities to maximize the return on their significant investment.

About the Author

Jeff Evans is consultant and project manager with Enspiria Solutions, Inc. He supports utility clients across North America with Advanced Metering Infrastructure and Meter Data Management System development and implementation. Prior to joining Enspiria, Jeff spent 15 years with Exelon Energy Delivery, where he led various metering and AMI projects. Jeff holds a Masters of Business Administration and a Bachelor of Science in Mechanical Engineering.



Seeing the Forest, Then the Trees

By Michael Madrazo, founder and President of Detectent

Using Automated Meter Reading (AMR) tamper information to identify high-quality theft cases was a strategy that never really materialized. Why? Because the valid information was lost in a mountain of distracting and bogus data. Some were due to utility activities and some of the distracting data were just plain false alarms.

So here comes Advanced Metering Infrastructure (AMI) to the rescue, right? Wrong—unless we use the data correctly. We will get consumption data and tamper flags much more frequently, but we'll be no better off unless we use better techniques to filter and analyze this new wealth of meter-reading data.

Valuable new data

Currently a typical one million-meter utility stores 24 million billing-related transactions over a two-year period. The transactions are usually actual meter reads, but can also be entries for transactions such as estimated readings or voucher bills. When new readings are captured, the oldest readings, usually from twenty-four months earlier, are eliminated or backed up on a different system. This scheme varies greatly, based on the type of Customer Information System (CIS) used, but this is the most common form of archiving and storing data. Twenty-four readings provide a good comparison of historical usage for Customer Service Representatives and provide enough history to support back billing for defective meters, under most state regulations. However, twenty-four monthly reads is not enough information for a consumer to make decisions about how they use energy and how best to conserve it.

A major driver for AMI instead of AMR is getting this decision-support information into the hands of the energy users. AMI will provide consumers with an hourly view of their energy usage, and will provide this view for a longer timeframe than in the past. For instance, utilities in California are planning to store electric readings at one-hour intervals for up to seven years. This offers customers a tremendous tool for analyzing their energy use and making adjustments to their behavior.

Using new data in new ways

The frequent data provided by AMI also provides new opportunities for utilities to detect metering issues and theft. However, before that can happen, all of this data must first be stored and managed. The same one million-meter utility that stores 24 million reads today will need to store over 60 trillion hourly reads over seven years. That is a whopping 60,480 million reads versus 24 million reads, for just one million meters!

Along with a greater volume of reading data comes an overwhelming amount of meter-tampering information. As a real-life example, a 1.4 million-meter utility with mobile AMR received 143,000 tamper flags over two years. A similar-sized utility, with a fixed network AMR system, received 6 million tamper flags from their nightly reads during the same period. A simple extrapolation tells us that with AMI, the number of tamper flags for that same-sized utility would exceed 100 million for the same two-year period.

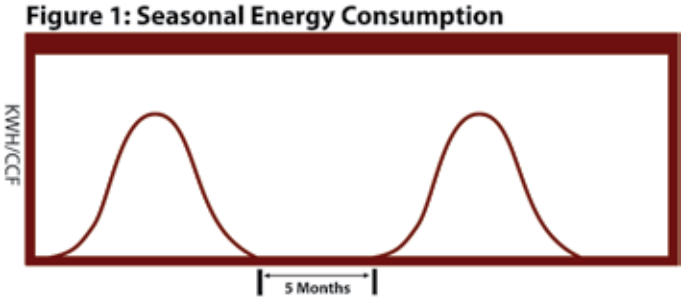
The Meter Data Management (MDM) suppliers have come to market with tools that can easily handle the AMI data storage amounts. They have also demonstrated their ability to process these large quantities of reading data for billing processes like VEE, complex billing, and data aggregation. But analyzing data for theft or meter failure is different. In response to utility demands, each MDM supplier has developed some form of theft-detection tools that can generate lists of suspect accounts, based on consumption and tamper data. However, the original problem is not solved. Too much data still exists and in fact, with AMI, it is one thousand times worse; the valid data gets lost in the reams of false alarms.

Given the fact that a typical one million-meter utility investigates 500 to 5,000 revenue protection cases per year, 60 trillion reads and 100 million tamper flags, of varying validity and value, does not help.

The problem with too much data

The following simplified electric or gas consumption plot represents a two-year profile for a seasonal home. This is a common situation for all utilities and is becoming more common, as the baby boomers retire and split their time between two homes to avoid extreme weather conditions.

Figure 1: Seasonal Energy Consumption

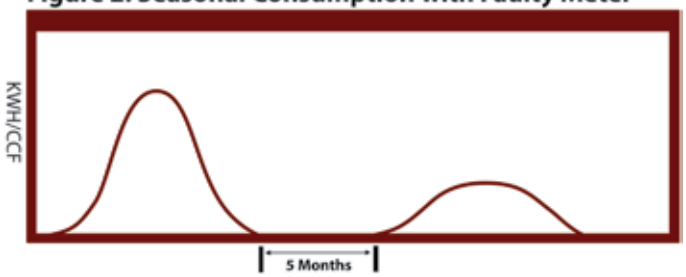


Assume that there is an AMI system that generates a "Zero Consumption for 24 Hours" flag each read and an MDM or CIS that generates a "Zero Consumption for 30 Days" flag each month. If meter problem detection is processed at the normal processing period of each system (hourly for AMI and monthly for MDM/CIS), then this seasonal residence, as shown in Figure 1, would have been the result of 3,600 "Zero Consumption for 24 Hours" flags and five "Zero Consumption for 30 Days" flags during the five months that it was unoccupied. The odds are that the flags would have either been turned off or ignored, or an overloaded revenue protection crew would have been sent out to investigate the situation. This visit would hopefully result in the account being noted as seasonal in the CIS, but may simply cause the flags to be turned off.

The above example highlights an instance in which micro-analysis of a situation generates many valid, but meaningless, events. We must be careful, though, as simplified schemes to minimize the data overload have been proven to hide the valuable information.

No harm was done in this case by turning off the annoying meter issue detection flags. But what if the meter had become faulty during the five-month period when the home was vacant? (See Figure 2.)

Figure 2: Seasonal Consumption with Faulty Meter



If the tamper flags were turned off for this account because of data overload, then the season-over-season drop will go unnoticed. If they were not turned off, then a new flag might come in from the MDM or CIS indicating a reduction from prior-year consumption; however, there are many valid reasons for this.

We have thousands of new data elements—how can we use them to find cases with valid issues without sending crews to every site? The answer lies in the use of multi-modal analytics.

Multi-modal analytics

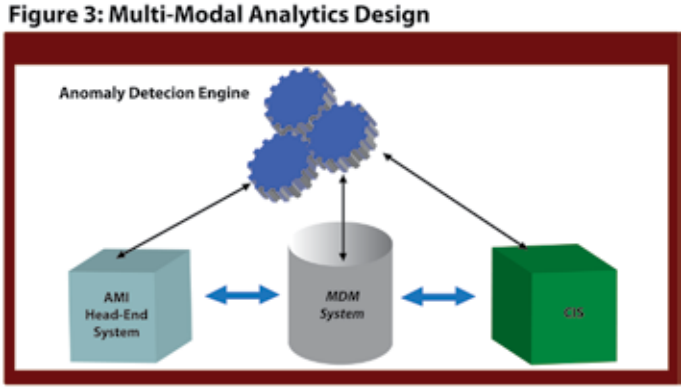
Remember the phrase "Can't see the forest through the trees." That is what multi-modal analytics is designed to solve.

With multi-modal analytics, patterns and statistics are analyzed on a monthly basis (the forest) and then analysis of interval data (the trees) is used to support the macro-level detections.

Limited revenue protection resources cannot afford the time it takes to chase tamper flags and consumption deviations at the microscopic level. Localized power outages, electrical work, and customer behavior patterns can mislead us if we look too closely. We need to take a step back and look at the forest before getting confused by focusing on the trees. We need the microscopic details, but we need them to validate what is seen on a macroscopic level. The two layers of analysis then compliment each other.

The design of a multi-modal analytics system can be seen in Figure 3.

Figure 3: Multi-Modal Analytics Design



The lower systems are the standard AMI components: AMI head-end, MDM, and CIS. The new component to the system is an Anomaly Detection Engine (ADE). This system sits above the massive flow of new AMI data, but requests and processes it as needed.

The term *anomaly detection* is used for the detection of abnormal patterns, not just theft or low consumption, since the same techniques can be used to identify targets for energy conservation programs, as well. The remainder of this discussion will, however, focus on the use of this analytic tool for identifying metering issues.

An ADE starts with information from the utility's CIS. This information is then supplemented with additional data from external databases, such as business listings and tax appraisal databases[1].

Inferential Modeling techniques are then used within the ADE to derive additional information about each account. Inferential Modeling techniques compare hundreds of features within the consumption profiles and classify accounts by attribute. The type of information that can be inferred about a residential account includes:

- Use of property (permanent residence, vacation home, vacant dwelling)
- Expected occupancy period
- Heating fuel type
- Air conditioning (yes/no)
- Square footage
- Swimming pool (yes/no)

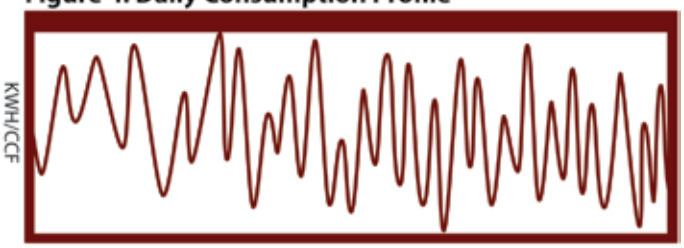
[1]*For further details see Electric Energy T&D Sept – Oct 2006: Integrating Data from Many Sources Provides New Opportunities in Energy Theft Detection*

The valuable inferred information from our previous example is the use of the property and the occupancy period. With the correct classification of the seasonal residence shown earlier, the ADE will be able to filter out the false flags it received from the Head-End, MDM, and CIS systems during the vacant period, but draw attention to the drop in consumption during the occupied period.

A risk score is assigned based on lower year-over-year consumption. This score increases as the pattern continues for several months. When the risk score reaches an established threshold, micro-analytics is initiated to validate the suspected issue.

The ADE requests finer resolution data in certain time periods from the Head-End, MDM, or CIS that is storing the interval data. Figure 4 shows the daily consumption profile for the month following the expected occupancy of Figure 2. The profile clearly shows an abnormally erratic consumption pattern, indicating mechanical failure of the meter.

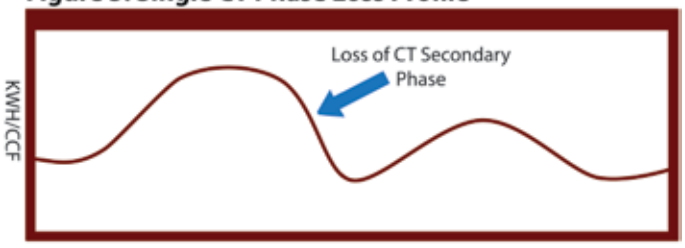
Figure 4: Daily Consumption Profile



A smooth daily profile, with reduced year-over-year consumption, would indicate a change in use or even an imminent property sale. Further investigation by an analyst would be required in this situation.

Another example in which multi-modal analytics is extremely useful is when a single secondary phase of a three-phase commercial Current Transformer (CT) service is lost. This can be caused by a secondary side fuse blowing, wiring issues during construction, or even a test switch being left open during routine maintenance. Figure 5 shows the most difficult situation to identify, when the abrupt drop in consumption occurs in the fall as the air conditioning load is dropping quickly. This type of metering issue is easily identified during peak or minimum-load periods.

Figure 5: Single CT Phase Loss Profile



The resulting measured consumption is approximately one-third less than the prior year, but energy-efficient HVAC changes on a commercial account would result in the same profile.

An ADE contains an algorithm that looks for one or more metering lines being lost on CT equipment. The risk score assigned for this case through this macro-analytics approach would not be very high, but it would identify the expected month of the event. A daily or hourly extraction of the readings during the month in question will show an abrupt loss of consumption on one line, and will justify a revenue protection investigation.

The investigation could have been initiated through single phase loss analysis at the MDM level, but there are many valid and temporary reasons for this to occur. There is no use sending a crew to the field to investigate a situation that is normal and will resolve itself.

The forest, then the trees

Macro-analytics techniques for identifying metering issues and theft have been successfully deployed for several years. In fact, over 20% of the commercial electric meters in the Unites States are being monitored by an ADE today.

The deployment of AMI does not necessitate the replacement of this proven revenue protection approach, but provides an opportunity to improve.

Anomaly Detection Engines are designed to process complex multi-dimensional models, but not in the volumes of multi-year hourly reads. The new AMI systems are designed to store and process large quantities of meter reading data.

The capabilities of these two types of powerful systems provide a great deal of value to utilities that deploy both.

About the Author

Michael Madrazo is the founder and President of Detectent, the pioneer in Anomaly Detection solutions for metered services. Detectent continues to develop leading-edge tools that integrate valuable information from many systems in order to identify cases of incorrectly-metered electric, gas, and water service. For more information about Detectent, visit www.detectent.com or call 760-233-4030.

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Alaska Power & Telephone: Energy Looking Forward

By Amanda Kelly

Overview

Alaska Power & Telephone Company (AP&T), which started in Skagway, Alaska in 1957, is celebrating its 50th anniversary as an employee-owned company this year. From humble beginnings offering standard hard-wire telephone service in Skagway alone, AP&T now offers a sophisticated range of energy and communication services to its customers.

In an era where much focus is placed on cutting-edge communication technologies, AP&T has quietly forged a leadership role in the field of renewable resource energy,

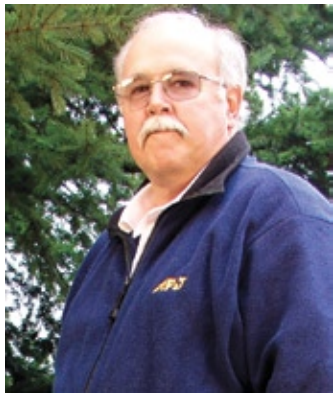
unique in a state that where most financial and energy interests are dominated by petroleum-based mega-corporations.

AP&T is on the forefront of the green movement in the power generation industry. The Washington-based company has shifted its carbon footprint enough to relegate the role of diesel generation to "back-up" duty in just over a decade. Just twelve short years ago, AP&T generated 99 percent of its energy using fossil fuels. Today, renewable-based resources generate 70 percent of that energy. AP&T views the remaining 30 percent as motivation to pursue further advances in alternative energy sources.

Recognized as one of the most progressive utilities in Alaska, AP&T's continued success lies primarily in the employee-owned company's willingness to promote and develop long-term reliable energy and communication solutions while capitalizing on the innovation and technical expertise of its personnel.

In the past five decades, a growing demand for energy coupled with oil prices at record levels created an evironment ripe to diversify the way energy in Alaska is produced. Since 1957, AP&T has grown from serving one community to more than thirty-three, with the number of households and businesses served climbing from a handful to over twelve thousand. The number of employees has increased from nine to 134, 28 of whom are full time employees in Port Townsend, Washington. AP& T serves an area spanning from communities above the Arctic Circle, to deep in the Wrangell Mountains, and throughout the islands of Southeast Alaska.

"This has been a fascinating five decades, with ups and downs, challenges and achievements," said Stan Selmer, previous chairman of the employee-owned company. "The technologies have changed and many of the names and faces have changed. But there have been two constants: Our commitment to having the best people doing right by the customers and communities we serve, and our firm belief in the power of innovation."



Seeking Alternatives

AP&T's commitment to innovation is best illustrated by what it has accomplished in the last decade in its power generating division. "Any time a company can migrate the impact of their fossil fuel generation to the extent AP&T has in the previous 12 years, you have to say that people are interested in hearing.," said Selmer. "Twelve years ago, 99 percent of the energy we produced came from fossil fuels. Today, of our production is renewable-resource based. That transformation has a twin benefit -- to the environment and to our customers because it improves our efficiency and effectiveness."

Geography and climate also make AP&T unique among the nation's power and telecommunications companies. "We've created power systems on hard-to-access, icy mountaintops and repaired phone lines on storm-battered islands," said Selmer. "What some people might consider above and beyond, AP&T people view as ordinary."

Most of Alaska cannot geographically be connected by an electrical grid. Therefore, each community (or small groups of rural communities) must create the energy needed by its residents. The state cannot purchase low cost energy because Alaskans are not electrically connected to the lower 48 states. Though most states have only a few electric utilities serving the entirety of each state, in rural Alaska, 86 utilities serve 181 communities.

The majority of energy generated in rural Alaska uses isolated diesel generators. In 1957, the year AP&T began, the cost of a barrel of oil was approximately three dollars. In August of 2007, that same oil sells for $74 per barrel. This price difference is what gave AP&T the impetus to look for alternatives to diesel generation.

Hydroelectric Opportunities

Alaska is rich in water resources. Looking toward water as a solution to Alaska's energy needs was an obvious and logical choice. In a state where resources are big business, AP&T decided to harness some of those same resources to provide reliable energy to its customers. Some might argue that the capitol costs of these undertakings are too high. The payoff comes from lessening the need for expensive and, at times, unpredictable fuel sources.

AP&T has more hydroelectric projects on line, under construction and in the planning stages than any other investor-owned utility in Alaska. "Research, design and advancement of sites conducive to environmentally sound renewable resource energy is a primary focus," said AP&T's President Robert Grimm. "It's important as Alaskans, and as a society, that we leverage practical renewable resource opportunities in ways that minimize our threshold of greenhouse gas emissions in the field of energy production."

The company's first completed major hydroproject was the Black Bear Lake (BBL) Project on Prince of Wales Island in Southeastern Alaska. At the time of its licensing and construction, the Black Bear Lake Hydro Project was the most ambitious project in AP&T's company history. Completed in 1996 with total project costs of approximately ten million U.S. dollars, the plant utilizes an alpine lake with a surface area of 215 acres for seasonal storage, rather than a dam. Energy is created using a siphon and penstock flowing to the power generation structure below. The project has a drainage basin of 1.8 square miles and provides most of the power for Prince of Wales Island. BBL Hydro is rated as a 4.5 Megawatt project with the lake spill elevation at 1,687 feet.

The Black Bear project was the first low impact environmental certification awarded by The Low Impact Hydropower Institute (LIHI) in Alaska and has earned national recognition for its "low-impact" on the environment. To earn certification, the Black Bear Lake Project was required to meet the following eight rigorous low impact criteria set forth by LIHI: water quality, fish passage and protection, river flows, watershed health, endangered species protection, cultural resources, recreation use and access, and whether or not the dam structure had been recommended for removal.

The institute's certification program was designed to help consumers identify environmentally sound, low-impact hydropower facilities for emerging "green" energy markets. Included among those currently serving as governing board members for LIHI are Ashok Gupta of the Natural Resources Defense Council, Nicole Silk of The Nature Conservancy and Robbin Marks with American Rivers.

AP&T's second major hydroelectric project is the Goat Lake Project, located near Skagway. The 204-acre glacially fed lake has the winter storage necessary to sustain year-round hydro generation. Also certified as low impact by LIHI, Goat Lake became operational in 1997 and was connected with Haines via a 15-mile submarine cable in September 1998. The submarine cable was laid in Taiya Inlet, a fjord with depths up to 1,500 feet. This 4.0 MW plant serves the communities of Haines and Skagway via a 35 KV submarine cable placed in the Upper Lynn Canal, the frigid body of water that connects the communities. This project allowed diesel-powered generators at both the Skagway and Haines plants to be quiet for the first time in nearly 80 years. Both of these projects required coordinating, educating and maintaining local support from business leaders, native corporations and residents as well as state and federal agencies.

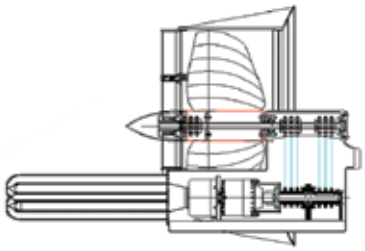
AP&T has other operational hydro-projects running and in planning and construction phases. In fact, in 1909 at the site of AP&T's original location in Skagway, a small hydroelectric plant was built. That plant is still in operation today as the 943 KW Dewey Lakes Hydro project and has been run by AP&T since 1957.

Other projects included the South Fork Project, a 2 MW run of river that works in tandem with Black Bear Lake to supply power to Prince of Wales Island. South Fork came on line and began providing power in December of 2005. The Kasidaya Creek Hydroelectric project, an expected 3 MW run of river located between Skagway and Haines, will begin producing power in spring of 2008. In addition to its Alaskan hydroelectric facilities, AP&T is a partner in the Pasabien hydroelectric project in Guatemala.

The continued quest to harness renewable resources is a mix of modern technology, environmental priorities and the ability to tackle complicated engineering problems. AP&T works with landowners, federal and state management and resource agencies, consumers and local government to offer safe, reliable and reasonably priced electric power.

Diesel-powered generation systems remain a long-term reality in some of the company's remote areas. It is possible that hydropower will eventually replace or supplement to an even greater degree the current reliance on fossil fuels.

Alternative Power Generation



AP&T now has the first, second and only hydro sites in the State of Alaska with the green low-impact certification on their energy projects. Other measures are being taken to further lessen the company's carbon footprint. AP&T is building a low-impact renewable energy system using "Run of River" technology on the Yukon River. Designed to serve customers in the City of Eagle and nearby Eagle Village, the pilot study will test the feasibility of utilizing river turbine technology to supplement or supplant existing diesel generation in rural Alaska. This is part of AP&T's plan to ensure long-term energy service and reliability for rural Alaskan customers.

The Eagle project will be the utility's first venture into the innovative field of river turbines. The 100-kilowatt "hydrokinetic" river turbine will be powered by the Yukon's powerful current. The cutting-edge technology relies on a low impact turbine that is adaptable to a variety of locations where sufficient flow of current is available.

Every winter, the Yukon River freezes solid for several months. Immersed in the current, the turbine will operate until just prior to the spring ice break-up of the river. At that time, a hole would be cut in the ice and the turbine will be lifted from the water and taken ashore for annual maintenance. Once cleaned and maintained, the turbine will be repositioned for another year of operation when the river is clear of the huge and powerful chunks of break-up ice. Potential obstacles to maintenance-free operation could come from sooner-than-anticipated wear caused by excessive abrasion from silt or vegetation debris.

While discussing while discussing the minimally invasive environmental impact the project will have, lead project engineer Ben Beste noted that photographs taken before and after construction would be almost identical. That is the kind of footprint AP&T is aiming for – power generation without disturbing the natural world Alaska provides.

The energy needs for the town of Eagle fluctuate between 7kW and 170kW. If this pilot project is successful, the installation of two turbines would virtually supplant the need to run diesel power generation for both Eagle and Eagle Village. The river turbine equipment under consideration for use has a rating of 100kW and is manufactured by the UEK Corporation of Maryland. Very little data exists worldwide on the feasibility of like projects.

It is expected evaluations of the River project will provide information on using the technologies for broader applications elsewhere. The anticipated payback of the unit is ten years. Nobody knows for sure what the actual life expectancy of these types of units is. Therefore, a portion of the project's intrinsic value is building the knowledge base associated with their operation.

The Future of Green Energy

"To take a leadership role in the development of new technologies is a natural extension of our vision as an employee-owned company and a practical opportunity to minimize our threshold of energy production related greenhouse gas emissions in the field," said APC President Robert Grimm.

For many years, the demand for cheap energy has put natural resources at risk. With the increasing price of fuels and the increasing need for energy, AP&T is putting fifty years of effort in the generation industry toward finding better ways to do business and serve customers.

Serves areas spanning from communities above the Arctic Circle, to deep in the Wrangell Mountains, and throughout the islands of Southeast Alaska. APT is committed to maintaining its legacy of a half-century of innovation and reliability, while developing long-term renewable energy and communication solutions that capitalize on the expertise of its skilled employee-owners.

For more information, go to www.aptalaska.com. For more information on the LIHI institute, go to www.LowImpactHydro.org

About the Author

Amanda Kelly covers oil and gas industry topics for local and national publications. A graduate of Salem State College in Massachusetts, Kelly has completed programs for writers at Harvard University, Bennington College and the University of Washington and is a member of the Pacific Northwest Association for Women in Communications and Digital Eve. She lives in Seattle, Washington.

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Quality Assurance: A Critical Component Of Any AMI Deployment

By Will McNamara, Principal Consultant at KEMA

Timely availability, reliability, and longevity of appropriate quality materials and supplies are critical to the well being of any AMI (Advanced Metering Infrastructure) or Smart Grid project. In the past, utilities have generally taken for granted that trusted suppliers would provide needed equipment, materials, and services in a timely and high-quality fashion.

Today, however, these suppliers are facing unprecedented demand, not only from the United States but also from utilities within Europe, China, and India. Accordingly, globalization of suppliers is occurring at an accelerating rate and many manufacturers and service companies will be facing the prospects of capacity constraints. While, in general, metrology vendors tend to be more established and mature businesses, many more AMI communications suppliers tend to be newer, smaller, and generally unproven companies with technologies that are in early stages of evolution. This has the potential to lead to further concerns regarding product availability and quality levels.

It is not unusual for items purchased from a local supplier to be manufactured in one foreign country with raw materials sourced from yet another. Given the increased level of capital requirements for AMI and Smart Grid mass-deployments today, the need to ensure high levels of reliability and to limit potential equipment failure has become increasingly important. To ensure financial success of an AMI or Smart Grid project, it is imperative that utilities planning or embarking on project deployment have thoroughly evaluated their suppliers throughout the supply chain processes to assess product design, operating performance, quality management systems, and delivery capabilities. Further, utilities considering AMI deployment are well advised to develop sufficient documentation outlining the standards, processes, and resource requirements to implement an end-to-end quality assurance (QA) program, from project conception to full deployment.

A thorough QA evaluation of potential vendors or supply chain partners should, at a minimum, include the following components:

- Equipment specification and design review
- Risk-based assessment of a supplier's manufacturing and delivery capability
- Assessment of a service provider's quality management systems and performance
- Ongoing performance reviews to assure continuing quality and on-time delivery
- Monitoring of performance metrics to identify early warning signs, should a supplier be faced with limited delivery capability or declining product performance quality

Beyond Product Testing

Some utilities may focus exclusively or too heavily on product testing when considering a possible vendor, often relying exclusively on random sampling methods. Certainly, meter testing and certification is a foundational step in determining whether a vendor can meet the specifications of a project, but there other equally important components that must be considered when making a QA determination. In fact, experience accumulated in the growing AMI/Smart Grid sector suggests that vendor evaluation and QA review should be approached from two distinct vantage points: AMI system technical requirements measurements (standard controls) and vendor risk profiling.

Even with standard controls, some utilities may not be applying sufficient processes to evaluate potential vendors and their solutions. Many new and next generation technologies are often associated with new and untested companies. In many circumstances, these attractive and promising new technologies may fit the technical requirements of a project and purchaser, but the company providing the technology may have an associated increased risk as a smaller firm with limited funding and minimal proven track record for scaling up design, manufacturing, service and delivery.

While minimum standard controls require meeting applicable ANSI, IEC and/or ISO standards for health and safety, data protection, data management, and other key factors, often utilities with limited resources are unable to conduct a more extensive due diligence. The multitude of subcontractors or original equipment manufacturers that a vendor may use can also create increased levels of risk in which a utility enters into lengthy and expensive contracts based on a cursory QA review. A utility entering into a contract with a particular meter manufacturer should be well-informed and have relevant supplier information at its disposal (e.g., patent ownership, on-going legal proceedings, supply chain contract details) and, if it is unable to conduct an evaluation beyond the minimum standards, it should seek out external assistance.

The risk-profiling component of the QA assessment should include on-site process audits performed for each vendor prior to initial production runs to ensure that vendors can comply with the utility-specific design, manufacturing, and delivery requirements. Physical inspections performed both at the vendor manufacturing site and the utility central receiving station should also be included, along with diagnostic tests performed on-site with remote equipment. Lab tests – including meter type tests and reliability (or life expectancy) testing – should take place prior to shipment or upon receipt of the equipment at the utility receiving unit, based on varying sample levels commensurate with prior results. Meter type testing should include functionality, environmental, and safety testing, as well as targeted testing of embedded components, such as integrated latching relay (remote reconnect/disconnect) switch testing.

Specific components that are candidates for testing would also include, but not be limited to:

- Mechanical requirements
- Insulation properties
- Accuracy requirements
- Electrical requirements
- Electromagnetic compatibility
- Effects of climatic environments

Development of a statistical system in which the meters are divided into groups (meters with the same metrological characteristics) will also provide longer-term analysis of key trends and potential predicative failure analyses, using random checking of each group on a periodic basis.

Vendor Risk Profiling

A utility may be able to perform adequate due diligence on the technical aspects of the product and yet find that the biggest risk is not in the technology itself but in the perceived – and often unknown – capability and capacity of the supplier to successfully scale and deliver the product. When considering acquisition of new technologies for large scale deployment in mission critical systems, the most significant purchase and project risk is likely the failure of the supplier(s) to be able to scale up processes and deliver the required product volume on the schedule and at the level of quality required. Traditional due diligence processes may not be able to adequately assess the capability and the subsequent risk for companies in these early stages. Put another way, the technical product due diligence process will provide some insight into basic capabilities of a potential vendor, but a utility would be shortsighted to make a selection decision based solely on technical capability.

Assuming that a company has demonstrated that their technology is solid and meets the business requirements, the challenge is developing a due diligence effort to appropriately assess the company's projected capabilities to deliver – sometimes in a situation where no track record or minimal demonstrated capability exists. This process therefore is fundamentally an assessment and "educated best guess" measure of "what will be" as opposed to the more traditional due diligence approach which focuses more on "what is." Utilities are finding that it is useful to employ external expertise to provide direct and independent validation of the capabilities espoused by vendors in their procurement responses.

A suggested first step is to classify all potential vendors into standard categories of "start up or emerging," "growing," and "mature." Characterization would generally follow a previously established set of criteria roughly defining the various business growth stages. The characterization helps to assure that the appropriate assessment criteria are applied.

For instance, start-up or emerging stage companies are not likely to be able to demonstrate the same financial strength or proven manufacturing capability that a mature stage company could provide.

Placing a large order with an emerging or early growth stage company is essentially an "investment" in that company. In most cases, a large order will provide the cash infusion needed for a small company to begin the process of scaling up to deliver design, manufacturing, quality assurance and delivery systems, some of which may not even exist at the time the order is placed. Given this – albeit simplified – similarity, the appropriate due diligence process used to screen an emerging or early growth stage company might be similar to the due diligence processes used by venture capitalists (VC) investors when considering investments in emerging or early growth stage companies.

There are a set of fundamental screening questions and criteria that VCs may typically use to evaluate a company's potential to succeed. These criteria go beyond the screening and assessment of the merits of the technology, product or service offering. A conceptual framework is typically built around investigating potential vendors within seven major focus areas, including some of the following:

- Company business plan
- Company basic financial performance and structure

- Management team, intellectual property, inventory and protections
- Current product status, sales and deployment
- Product development roadmap
- Scalability (including design, manufacturing, QA, sales, delivery and support)
- Investment plan

In many cases, a vendor's initial or subsequent business plan can provide the basis for a number of these requested areas. More mature companies could be asked to provide current and three-year financial reports (e.g., income statement, balance sheet, capitalization/debt structure); one-, three- and five-year budget projections, including capital requirements to meet sales projections; and other applicable financial records.

Other relevant financial areas for exploration could include the following:

- Insurance and bonding instruments are sufficient to protect and cover both physical and financial assets
- Credit ratings are at investment grade or better (S&P ratings are at BBB- or better (up to AAA) or Moody's ratings are at Baa3 or better (up to Aaa))
- Current funding (capital) sources are sufficient to cover product development roadmap efforts for the next three years
- Analyst coverage (if applicable) deems company a positive performer or better, or identifies no significant impediments to meeting financial targets and growth objectives
- Documentation exists to demonstrate compliance to Sarbanes-Oxley financial controls, if applicable
- Business qualifications, standards and ownership requirements (e.g., MWBE, US Corporations/foreign exclusion)
- Minimum levels of financial capability or damage provisions
- Bonding, collateralization, and security requirements
- Contract exception policies

In closing, there are various risk assessment and characterization criteria that should be considered as suitable for increased levels of due diligence that would support the needs of utility QA processes. Of course, the unique aspects of each AMI/Smart Grid deployment warrant a customized QA process that use these general touch points as a foundation.

About the Author

Will McNamara is a Principal Consultant at KEMA. He is a regulatory and legislative affairs expert with 15 years of energy industry policy-making, rate design, expert testimony, and lobbying experience. His expertise includes developing AMI policy and managing business plans and regulatory filings within the areas of energy efficiency, demand response, and smart grids.

REPRESENTATIVE QUESTIONS TO ASK OF EACH VENDOR DURING AN ON-SITE RISK PROFILE:

- How well defined are processes to determine and review AMI requirements as they are established, and to track and ensure that each requirement is met, each requirement is traceable from source to component? Does this system effectively address configuration management concerns as architecture evolves and when requirements change?
- How well does the organization have rigorous and forward-looking program management capabilities that will ensure that AMI timeline requirements are met, and that risks to schedule are identified, communicated, and mitigated in a timely manner?
- How well does the organization have the resources and capabilities to effectively address the issues raised during this assessment?
- How well can the organization effectively collaborate with the utility and with other AMI vendors and with supply chain sub-systems on the AMI development?
- How well does the organization have experience in development of open architecture systems and have they demonstrated this through effective application of technical and regulatory standards, and through involvement in relevant technical consortiums?
- How well does the organization have formal and effective processes and systems for cost analysis and control, and do these systems encompass all cost sources throughout all phases of the AMI program?
- How effectively will the vendor be able to meet product reliability requirements established by the utility AMI team?
- How effectively will the vendor be able to meet product performance requirements established by the utility AMI team?
- How effectively will the vendor be able to meet system security requirements established by the utility AMI team?

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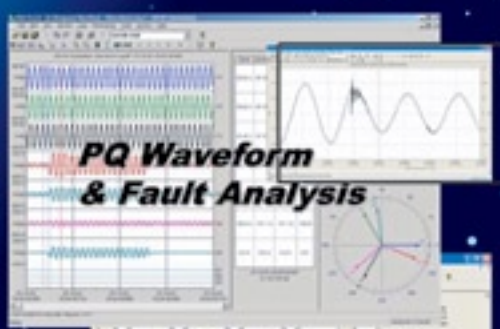

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