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HOW REAL TIME DATA YIELDS PAYOFFS FOR POWER DISTRIBUTION SYSTEMS

Electric Energy T&D MAGAZINE

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Ryan Meller
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Northwestern Rural Electric Co-operative Association, Inc.

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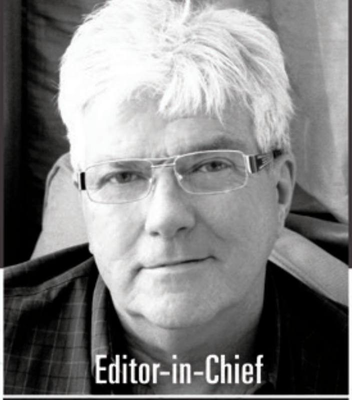


TERRY WILDMAN

CIGRE 2016, the Leading Event for Power Systems Experts

Every year there are dozens of conferences dedicated to electrical transmission and distribution.

One of the key events is CIGRE Paris for Power Systems experts.

During 5 days, there were no less than 249 exhibitors attended by many more experts than ever – technical experts, decision makers, top power product manufacturers, TSOs, DSOs, universities, the entire power systems stakeholders, and more.

It was announced that Robert Stephen (South Africa) was named as the new President of CIGRE and the new Treasurer, Michel Augonnet (France). Mark Waldron (United Kingdom) has been re-elected as Technical Council Chairman.

What is CIGRE ?

CIGRE is a permanent non-governmental and non-profit International Association. Based in France, it was founded in 1921 and is dedicated to the development of the power supply sector through the identification and the development of solutions to industry issues. With members in more than 80 countries, it is the leading worldwide organization on Electric Power Systems, covering their technical, economic, environmental, operational, organisational and regulatory aspects. (www.cigre.org)

CIGRE key figures

58 National Committees
Working Groups: 241 working groups, 3 801 Experts including 295 women from 64 countries.
Many publications: www.e-cigre.org
Tutorials NEW: 52 participations from Study Committees – 63 tutorials delivered
Many Events: Symposia, CIGRE 2016 Technical Exhibition, etc..

Aims of CIGRE

- Facilitate and develop the exchange of knowledge and information, in all countries as regards the production, transmission and distribution of electricity.
- Add value to the knowledge and information exchanged
- Make managers, decision makers and regulators aware of synthesis of CIGRE's work, in the area of electric power systems.

CIGRE 2016 Session

CIGRE 2016 is an event designed to meet the expectations of all participants through a week-long Technical Programme & Exhibition.

During the Opening Ceremony, Claudio FACCHIN, President Power Grids Division at ABB Ltd. made a speech on *The Big Shift - Enabling the Evolving Power System.*

> "Electricity continues to be the most versatile and widely used form of energy but has also been a major contributor to carbon emissions. With growing awareness and focus on mitigation, the challenge we face is to balance the growing demand for electricity with minimal environmental impact. This has led to an influx of renewables into the grid and their often remote location and intermittent nature, combined with a significant increase in distributed generation has created new supply side challenges.

At the same time we also see new demand loads like electric vehicles and data centers as well as smarter homes and buildings. All these complexities require the evolving power system to be increasingly flexible and interconnected, as well as more reliable and intelligent. This is also driving the development of ultra-high-voltage AC and DC transmission, more eco-efficient and resilient products, power quality and grid stabilization technologies, service and asset health management solutions as well as emerging innovations like energy storage and micro grids. And key to managing this 'big shift in power' is the increasing digitalization and automation of the grid, the growing deployment of software and the convergence of information and operational technologies, as the power sector leverages the internet of things, services and people."

Followed by the opening panel on distributed generation impact on the bulk connected network – a global perspective, with a musical interpretation to illustrate the conference. "Electric energy systems are in a transition phase all over the world. Now we are moving into a direction of shared responsibility."

Followed by a workshop on large disturbances: System Disturbances & Market Disturbances

During 5 days, many tutorials, 16 group discussion meetings, 16 'poster sessions' (to allow delegates to meet with papers authors) and private meetings.

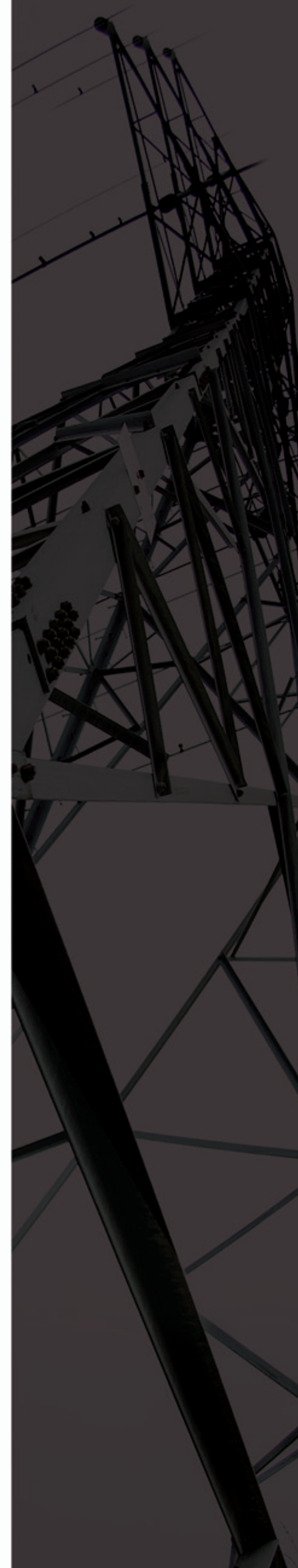
These included:

- Protection and Automation
- Materials and Emerging Test Techniques
- System Technical Performance
- Distribution Systems and Dispersed Generation
- Substations
- Electricity Markets and Regulation
- System Development and Economics
- System Environmental Performance
- Transformers
- Information Systems and Telecommunications
- Rotating Electrical Machines
- Overhead Lines
- HVDC and Power Electronics
- System Operation and Control
- High Voltage Equipment
- Insulated Cables

A technical exhibition ran in parallel in the same location **with 249 exhibitors, the top names of the Industry**, from all over the world.

With 89 countries represented, CIGRE has become the international leading event for technical experts worldwide sharing knowledge to improve the electric power systems for today and tomorrow.

The 47th Session will take place in 2 years in Paris (August 2018).



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Entergy Corporation Entergy Named as National Leader in Economic Development

Ninth Consecutive Year on the List

September 2016

Entergy Corporation (NYSE: ETR) has been named one of the nation's Top 10 utilities in economic development for 2015 by Site Selection magazine for the ninth year in a row for its integral role that resulted in nearly $10.3 billion of capital investment and the creation of over 4,800 new jobs in its service territory

The ranking may be viewed in the September 2016 print edition and on Site Selection's website.

"Entergy is honored to be recognized again by Site Selection magazine as one of the top national utilities in economic development," said Paula Waters, vice president of Entergy's utility sales and development services department. "As active participants in our region's economic development process, and through our close work with our state agencies and local communities, we successfully secured new load growth and recently helped drive $90 million in new sales from corporate facility and other projects. Entergy will continue to play an integral role in the ongoing industrial growth taking place in our own backyard."

Criteria used by Site Selection to choose the top 10 includes the utility's use of innovative programs and incentives for business and the utility's own job-creating infrastructure and facility investment trends. Entergy provides companies with access to essential information to locate, expand and promote their company in Arkansas, Louisiana, Mississippi and Texas. In addition, Entergy provides companies with services in site selection, project management, large project transmission and distribution engineering and contracts.

For more information on Entergy's economic development efforts, please go to goentergy.com.

U.S. Department of Energy Department of Energy Invests $1.2 Million to Advance National Lab Partnerships with Manufacturing Leaders

September 2016

Today (9/27), the U.S. Department of Energy announced the initial selections for the second cohort of the Technologist in Residence (TIR) Program. Three national laboratories will receive nearly $1.2 million to advance collaborative research and development focused on improving the manufacturing processes of industry partners.

The TIR Program is designed to streamline engagement and increase collaborative research and development between national laboratories and private-sector companies. The program partners a senior technologist from a national laboratory with an industry professional from a clean energy manufacturing company or consortium of companies.

The selected Technologist in Residence pairs are:

Argonne National Laboratory and Kyma Technologies
This partnership will focus on the development of advanced semiconductor devices for use in advanced power electronics, optoelectronics, solid-state lighting, and photovoltaics. The researchers will investigate the manufacturing of ultrahigh-quality, bulk, single-crystal materials for semiconductor devices.

Idaho National Laboratory (INL) and DuPont
This partnership will focus initially on biofuel production and the opportunities to optimize an integrated ethanol cellulosic technology pathway from feedstocks through bioconversion. The technologists at INL and DuPont will partner to streamline engagement across the national lab complex, break down barriers in working with the national labs, and increase collaborative research and development between national labs and DuPont.

Oak Ridge National Laboratory and Pioneer Natural Resources
This partnership will focus on advanced materials and coatings, smart parts and sensors, advanced material design, and additive manufacturing, leveraging Oak Ridge's strong expertise and resources in advanced manufacturing.

The TIR program increases industry engagement by capitalizing on the Department of Energy's 17 national laboratories' rich history of industry partnerships and commercial impact, and helps to bridge the gap between the private sector and the national laboratories. Through this initiative, our industry partners can better understand and tackle their most important problems and discover the lab capabilities that can best solve them.

This announcement follows the successful launch of TIR in December 2015, when seven industry-lab pairs including national companies like Proctor & Gamble, Hewlett Packard, and Cummins were selected to undertake advanced research in clean energy manufacturing and establish mechanisms that will help interested companies more easily leverage the national lab network in the future. Learn more about the initial round of our Technologist in Residence Program.

Applications for the TIR Program are accepted and evaluated on a rolling basis to give lab and industry pairs the opportunity to apply according to their business schedule. Interested national labs and companies may determine areas of mutual interest, identify technologist pairs, and apply to TIR through the Lab Call for Proposals.


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US Trade & Development Agency USTDA Advances Smart Grid Development In Vietnam

September 2016

Today (9/22), the U.S. Trade and Development Agency provided technical assistance to Electricity of Vietnam Central Power Corporation (EVNCPC), a state-owned electric power utility, to help them modernize their enterprise architecture for smart grid deployment.

Responding to rapid electricity demand growth, particularly in central Vietnam, EVNCPC is developing an overall information technology (IT) and smart grid strategy, including an implementation plan and investment schedule, to improve the quality of supply and service to its customers. The technical assistance will provide detailed recommendations to automate and upgrade IT systems in order to integrate smart grid applications that can help EVNCPC efficiently manage its operations and business processes.

EVNCPC CEO Tran Dinh Nhan signed the grant agreement along with Commercial Counselor Elizabeth Shieh of the U.S. General Consulate Ho Chi Minh City. Commercial Counselor Shieh emphasized the United States' interest in strengthening support for the development of Vietnam's energy industry. She noted, "This study will undoubtedly help Vietnam's power sector become more effective and efficient. It will serve as the basis for expanded industrial production in Vietnam, particularly in central Vietnam, leading to better living standards for the Vietnamese people."

This project builds upon USTDA's previous efforts to help its Vietnamese partners identify and deploy smart grid solutions. Combined with the ongoing efforts of U.S. companies, it will increase trade ties between the U.S. and Vietnam.

U.S. businesses interested in submitting proposals for this USTDA-funded technical assistance should visit the Federal Business Opportunities (FBO) website at www.fbo.gov. A link to the FBO announcement will be posted to USTDA's website at https://www.ustda.gov/business-opportunities.

ABB wins $85 million in orders to strengthen power grid in Canada

Ultra-high voltage circuit breakers and power transformers to support upgrade of Quebec grid

September 2016

ABB has won orders worth over $85 million from leading Canadian utility Hydro-Québec (HQ) to upgrade its 800-kilovolt (kV) air-insulated switchgear (AIS) substations and transmission grid with state-of-the-art circuit breakers, power transformers and shunt reactors. The upgrade is driven by the increasing demand for power and the need to integrate new sources of renewable energy.

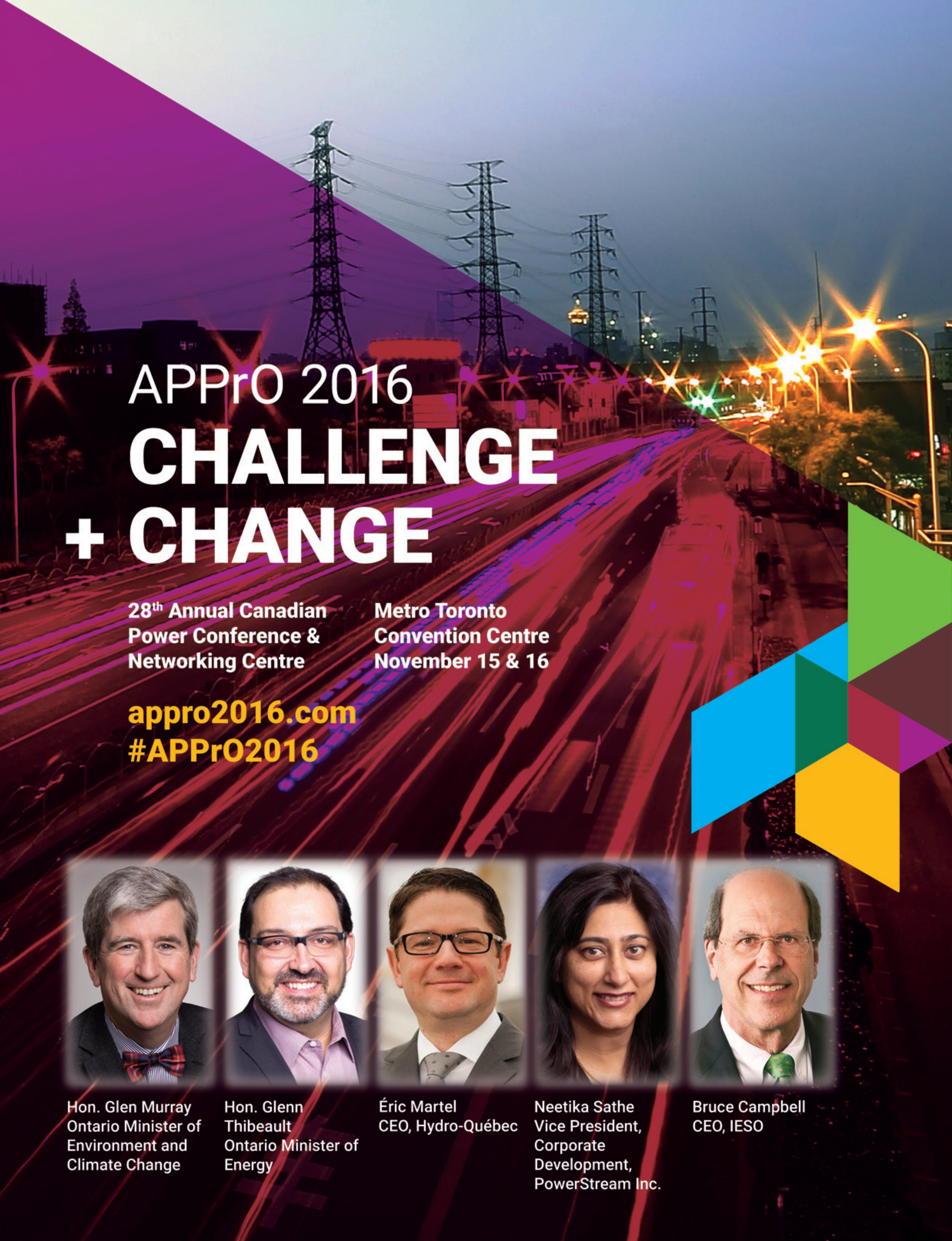
HQ operates one of the largest 800 kV networks in the world, a large part of which was originally developed in the 1960s and 1970s, and ABB has been involved in the modernization of its power infrastructure over decades.

"We are pleased to continue supporting Hydro-Québec, in their ongoing efforts to strengthen Canada's power infrastructure," said Claudio Facchin, President of ABB's Power Grids division. "ABB's leading-edge technologies will help boost the integration of renewables, deliver additional power and enhance transfer of electricity over long distances. Ultra-high voltage transmission is a key focus area within our Next Level strategy and a key differentiator for ABB."

As part of the project, ABB will design, deliver and commission the state-of-the-art circuit breakers with polymeric insulators, to enhance safety and robustness. It will also design, manufacture and deliver 450 megavolt-ampere (MVA) autotransformers and 735 kV shunt reactors.

Circuit breakers are a vital component of substations, essential for safe, reliable and efficient switching operations. ABB's live tank breakers are the most widely deployed circuit breakers in operation around the world, providing a cost and eco-efficient, flexible and well-proven solution.

Transformers are integral components of an electrical grid, and essential for the efficient and safe conversion of electricity between different voltage systems. ABB's transformer portfolio includes power transformers rated up to 1,200 kilovolts, dry- and liquid-distribution transformers, traction and special application transformers as well as related services and components.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INDUSTRY NEWS INDUSTRY NEWS INDUSTRY NEWS

Dubai Electricity and Water Authority DEWA records increase in use of its smart services

September 2016

Dubai Electricity and Water Authority (DEWA) has recorded an increase in the use of its smart services during Q2 of 2016, with the smart adoption rate having reached 68%, from a total of 2,492,890 smart transactions. This has led to a positive effect on the environment by reducing 8,521 tonnes of carbon dioxide emissions, which is equivalent to the planting of 42,607 trees in approximately 80 football fields. DEWA's smart adoption is yet another milestone in its efforts to reach its vision of becoming a sustainable innovative world-class utility and to exceed the expectations of Dubai Smart Government.

"DEWA's vision is inspired by the directives of HH Sheikh Mohammed bin Rashid Al Maktoum, Vice President and Prime Minister of the UAE and Ruler of Dubai, to reduce the number of visitors to government departments by 80% by 2018. DEWA's smart services play an important part in achieving this goal and also contributes to the Smart Dubai initiative, which was launched by His Highness to transform Dubai into the smartest and happiest city in the world. The initiative contributes to achieving a significant improvement to the services provided to customers, and it enables the management of the city's utilities and services using smart networked systems. DEWA completed its smart transformation less than a year after the Smart Dubai Strategic Plan was launched. This is an important addition to DEWA's record of achievements," said HE Saeed Mohammed Al Tayer, MD & CEO of DEWA.

"DEWA realises its vital role as the exclusive provider of electricity and water in the Emirate. Therefore, DEWA works constantly to develop services that match Dubai's ongoing development and to meet increasing demand. DEWA provides its customers with smart, fast, easy-to-use, and integrated services that are available around the clock. Customers are able to activate, or deactivate electricity and water services at the click of a button on DEWA's smart app. This reflects DEWA's commitment to use technology to make people happier by increasing the efficiency of its services, and advancing Dubai's global reputation," added Al Tayer.

DEWA's smart application was installed and updated 781,574 times in 2015, and 335,934 times in 2016: a total of 2,300,228 times since 2010. There were 2,896,997 transactions on DEWA's website in 2013, and 3,837,645 in 2015. There were 2,060,347 transactions made in Q2 of 2016. The adoption rate of available services via DEWA's website stood at 52.9% in 2013, and 57.31% in 2014. It then grew to 59.17% in 2015, and reached 60.67% in Q2 of 2016.

There were 16,554 transactions made via DEWA's smart app in 2013, and 114,600 in 2014, with 323,739 in 2015. There were 323,739 transactions made during Q2 of 2016. DEWA's smart app provides its customers with a unified and seamless experience. The app is both efficient and easy-to-use, and combines many features, which enriches the user experience. The app introduces a new and innovative way of displaying the services by providing a single integrated package that provides all the services and features that the user needs on the homepage.

As soon as users open the homepage of their accounts, they can find many convenient services, including bills, and graphs to check and compare their consumption. The app also gives customers the option to add other accounts to their main account, so that they can manage more than one account at the same time. They can add photos for each account to identify them instead of memorising account numbers.

DEWA's website provides comprehensive services that meet the requirements of everyday life: services that are easy, integrated, and efficient; providing easy browsing and online access to services. The website offers special services for each category of customer. The website was recently revamped to meet customer needs, services, and improve overall quality of all services.

All services have been divided into more specific categories, according to customer requirements, to facilitate and speed up surfing and navigation. The website layout is clearer and more transparent in terms of displaying the needed steps. The design is unified and compatible with all smart devices and phones. DEWA has given priority to the customer experience while revamping its website and updating its smart applications. These initiatives improves DEWA's services to meet the requirements of its customers and make them happier.

DEWA smart applications support a range of operating systems, including iOS, Android, Blackberry and Windows. The app is also available on IoT (Internet of Things) technologies including: Samsung entertainment devices, Samsung Gear watches, Apple watches, and eLife by Etisalat.

Angela Buk joins DTE Energy as chief investment officer

September 2016

DTE Energy named Angela Buk to the position of chief investment officer, leading the company's investment policy and strategy. Buk will manage DTE's employee retirement plan investments and other company trust investments. Buk most recently led the Alternative Investments team in the Treasury Asset Management Group at Fiat Chrysler Automobiles (FCA).

"We are excited to have Angie join our team," said Mark Rolling, vice president and treasurer, DTE Energy. "Angie is a highly-qualified investment professional whose experience and education makes her well-suited to lead the strategic investment of the company's $9 billion in trust assets."

In her role leading FCA's Alternative Investments team, Buk was responsible for a multi-billion dollar portfolio of alternative investments including hedge funds, real estate, private equity and opportunistic investments. Buk was also a member of the investment committee responsible for oversight of $30 billion of global employee benefit assets and other trust investments. Prior to this role, Buk lead and managed a team responsible for investment operations, compliance, risk management and defined contribution. Within FCA, Buk progressed through various roles of increasing responsibility in Corporate Finance & Securitization, Treasury Planning & Project Finance and Sales & Marketing Finance. During her tenure at FCA, Buk successfully developed and led a defined contribution plan redesign and implemented new alternative investment portfolios.

Prior to FCA, Buk served as a senior auditor with Deloitte LLP, performing audits of pension plans, financial institutions and real estate firms, servicing Fortune 500 clients.

Buk received her bachelor's and master's degrees from the University of Michigan, Ross School of Business. She is a Certified Public Accountant (inactive) and a Level II candidate in the Chartered Alternative Investment Analyst program.

INDUSTRY NEWS

UL Acquires AWS Truepower to Expand Global Renewable Energy Portfolio

Acquisition strengthens UL's position in full lifecycle solutions for Wind and Solar Energy Sectors

September 2016

UL, a global safety science leader, announces the acquisition of AWS Truepower, a leading energy engineering services and advisory firm. This achievement expands UL's global renewable energy portfolio by strengthening full lifecycle solutions for wind and solar energy sectors.

AWS Truepower is an Albany, NY-based company providing renewable energy services through five business units covering project advisory, performance engineering, due diligence, information services and grid solutions. Its service portfolio complements UL's current renewable energy offering focused on testing, inspection and certification as well as performance verification of solar, wind, batteries and energy storage systems. The acquisition supports UL's global expansion strategy as many countries are pushing for energy independence, energy security and environmental sustainability. Hundreds of GW's of energy capacity installed globally is pushing the demand for energy assessments of new projects coming online and ongoing support. AWS Truepower's services are crucial in supporting this growing demand.

"There is strong alignment between the two brands," said Jeffrey Smidt, VP & General Manager for UL Energy & Power Technologies. "UL and AWS Truepower have a shared mission and complementary businesses. As the market for renewable energy increases and demands a full life cycle service offering for renewable energy projects, the combined portfolios enable us to capture additional business globally."

"We are excited by this opportunity to merge forces with UL and provide best-in-class services and products to the renewable energy industry," said Bruce Bailey, former CEO of AWS Truepower and new VP, Renewable Energy for UL. "Clients can rest assured that customer service and technical quality will remain our top priorities, and that our newly integrated capabilities will deliver even more value."

AWS Truepower's employees will join UL and remain with the company. For the time being, AWS Truepower will continue operating under its current brand name. The transaction closed on September 26, 2016.

About UL

UL is a premier global independent safety science company that has championed progress for more than 120 years. Its more than 11,000 professionals are guided by the UL mission to promote safe working and living environments for all people. UL uses research and standards to continually advance and meet ever-evolving safety needs. We partner with businesses, manufacturers, trade associations and international regulatory authorities to bring solutions to a more complex global supply chain. For more information about our certification, testing, inspection, advisory and education services, visit http://www.UL.com.

About AWS Truepower

For over 30 years, AWS Truepower has been a global leader in renewable energy. Through its expertise in engineering services, energy and resource solutions, software, and data platforms, AWS Truepower has helped develop, acquire, and support the complete wind and solar project development lifecycle. It has worked on the design and assessment of over 120,000 MW of renewable energy projects, both on land and offshore, in over 80 countries. Expert advice, accurate assessments, and innovative tools have helped renewable energy projects evolve into durable operating assets, which are both reducing humanity's global carbon footprint and generating healthy financial returns. Headquartered in Albany, New York, AWS Truepower has offices in North America, Europe, Latin America and Asia. Learn more about the company online at awstruepower.com.

Manitoba Hydro expands Power Smart* rebate promotion

September 2016

Manitobans can now save more energy-and money-through Manitoba Hydro's newest Power Smart* promotion.

Along with the return of instant rebates on energy-saving LED bulbs, Power Smart* now offers instant rebates on a number of other new energy-efficient technologies.

From September 30 until October 31 at participating retailers province-wide, consumers can get instant rebates on LED fixtures, lighting controls, smart power bars, plug-in timers, low-flow showerheads, weatherstripping and window insulating film kits.

And until January 31, 2017, customers will receive a Manitoba Hydro bill credit for the purchase of a "smart thermostat" and/or ENERGY STAR® certified washing machine or washer/dryer pair. Customers can purchase eligible products from any retailer of their choice, or buy online, and then visit Manitoba Hydro's website at hydro.mb.ca/savings to apply for their rebate.

Smart thermostats are Wi-Fi connected devices that provide a greater degree of control over a home's temperature settings. Many smart thermostats can learn individual heating and cooling preferences and detect indoor humidity and weather patterns to optimize warmth and comfort.

Unlike manual and programmable thermostats, smart thermostats use algorithms to make heating and cooling suggestions, generate reports, and notify a homeowner of possible system events and performance issues.

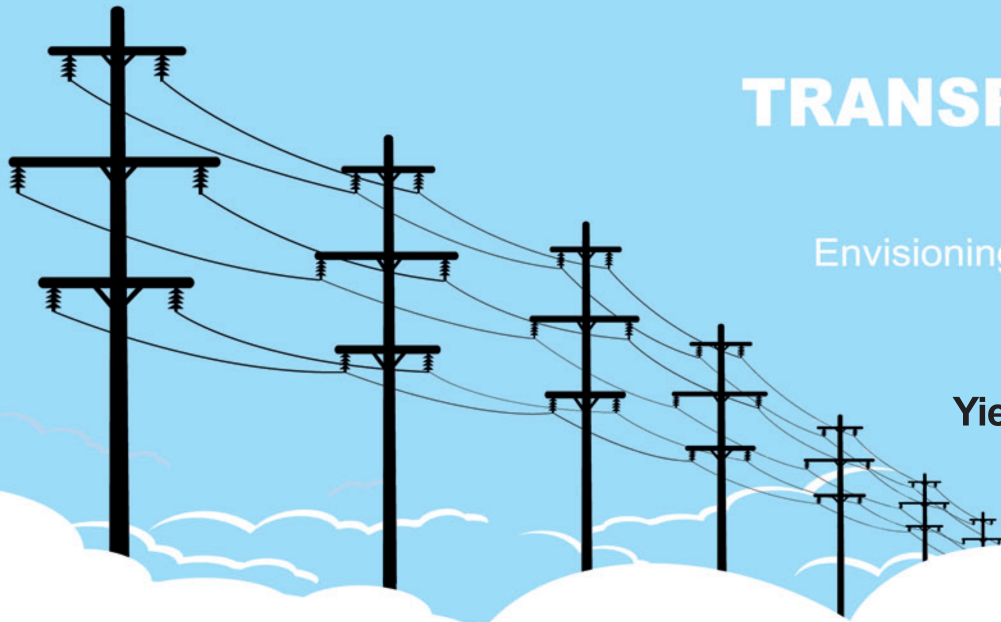
Since the first LED rebate program launched in the fall of 2014, more than 85,000 households have purchased ENERGY STAR® certified LED bulbs, saving approximately $3.6 million a year on their electricity bills. LED bulbs use 80 per cent less energy than incandescent lights.

"Our customers have responded overwhelmingly to our earlier promotions by purchasing and using energy-efficient LEDs in their homes," said Lloyd Kuczek, Vice-President of Customer Care & Energy Conservation for Manitoba Hydro.

"Our goal with this new promotion is to continue to help our residential customers learn more about other energy-efficient technologies so they can lower their energy bills. These items are easy for most homeowners to use and they will see the benefits almost immediately."

THE GRID TRANSFORMATION FORUM

Envisioning the 21st Century Grid



How Real Time Data Yields Payoffs for Power Distribution Systems

Analytics and real-time data play a prominent role in today's utility grid, each opening opportunities for both large investor owned utilities as well as smaller municipal and co-op utilities to better operate their networks. Maneuvering through layers of complicated architecture and vast amount of data is a challenge for utilities that are looking to both retrofit an outdated, underinvested distribution network while modernizing it for the adaptation of new energy resources. We are talking with Erik Christian, vice president, smart grid of Aclara, about using analytics to bridge that gap.

EET&D: What are the biggest challenges utilities face today with respect to the distribution network?

Christian: While the distribution network is geographically the largest section of infrastructure within most utility grids, it is often a piece that continually goes without investment. With the 21st century needs for electricity continuing to rise, these aging pieces of infrastructure need updating. The increased penetration of renewable energy, such as wind and solar, also creates stress the distribution network must overcome. As we look to the future, a lack of investment in distribution infrastructure could mean more power outages and challenges for utilities and consumers.

EET&D: What has changed for the distribution system, why so much focus on it today?

Christian: Traditionally, energy was generated and distributed to customers in a predictable way. Today's grid is dynamic. The addition of renewable energy and self-healing systems means the grid of tomorrow needs to adapt to a quickly changing environment. The first step in that evolution is visibility into what's actually happening on the grid, which requires utilities to invest in systems that provide data on grid health.

EET&D: What role does data play in regards to modernizing the distribution network?

Christian: Collecting data from within the distribution network allows the utility to proactively monitor the health of its network. As the grid evolves, raw data isn't enough to make informed decisions about the status of the grid. To obtain true situational awareness, utilities need to use analytics that make data actionable. Business intelligence from advanced analytics improves the efficiency and reliability of power distribution to customers. Using smart-grid sensors and analytic software to monitor critical infrastructure assets allows utilities to change their maintenance schedules from calendar-based to condition-based. This ultimately minimizes cost and increases the reliability of running the grid.

EET&D: What tools have traditionally been available to monitor the distribution network?

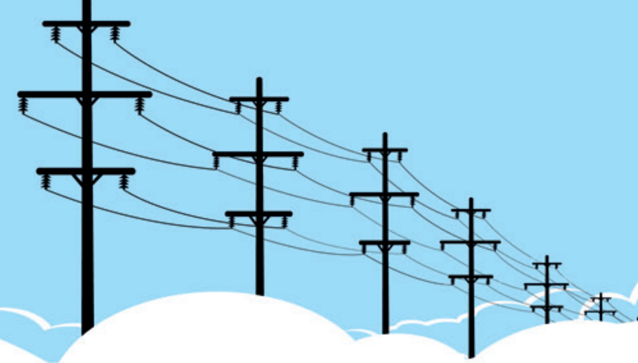
Christian: The issue utilities faced in sourcing monitoring solutions over the last few decades is that legacy monitoring equipment was designed for specific applications. Typically, these older generations of technology were unable to configure and mold to specific networks' challenges and demands.

Operators used FCI's for fault identification, load loggers or chart recorders for substation monitoring and power quality analyzers for troubleshooting. These devices are often static and non-communicating, so people have to collect and analyze data from them, increasing operating expenses. Yet, despite utilities using valuable OpEx to collect the data, it is usually outdated when it gets into the hands of decision makers.

EET&D: In today's grid, are these solutions adequate to properly monitor the network?

THE GRID TRANSFORMATION FORUM

Envisioning the 21st Century Grid



Christian: Today's grid requires real-time monitoring and analytics that can condense a large amount of data into bite-size, actionable pieces of intelligence. Adaptive technology that addresses multiple applications with a single platform provides the best business case for utilities. Systems that marry advanced distribution monitoring, gather intelligence from residential and commercial meters and identify precursors to fault events best serve the needs of their utility customers today.

EET&D: What role do smart grid sensors and analytics play in gaining network visibility? Are there areas of the grid that are unmonitored today?

Christian: To immediately improve the reliability and efficiency of the grid, utilities need to quickly and safely retrofit their networks with advanced monitoring solutions. The most effective way to do this is to use smart grid sensors and analytics software for critical applications, such as fault location, asset management and active monitoring of renewable energy. As the complexity of the grid continues to grow, it will create additional applications for advanced monitoring solutions.

The strongest application still requires an adequate business case for utilities to invest. In the past, the cost of traditional monitoring equipment was often prohibitively high, limiting the amount of monitoring a utility could afford. For example, substation monitoring has conventionally required substantial investment for electric utilities. The long-established way to outfit a distribution substation for monitoring required current transformers, potential transformers, remote terminal units, communications, months of engineering studies, and ultimately an outage to install all of the equipment. Once requiring a major financial investment, the addition of smart grid sensors allows utilities to implement a single monitoring platform and integrate it seamlessly with SCADA systems, providing critical situational awareness at a fraction of the cost of the old way of doing things.

EET&D: For utilities who are thinking about implementing advanced monitoring solutions, what are key areas they should consider?

Christian: The dynamic nature of the 21st century grid will mandate monitoring solutions to be reliable and configurable to adapt to new challenges. Sensors with batteries mean utilities have to spend valuable operating dollars and crew cycles replacing batteries when they no longer work. Sensors must also be software defined and over-the-air upgradeable. Analytics software is the key to maintaining a modern grid, but the solution architecture must be scalable to make a large impact.

EET&D: What do you think the future of distribution grid monitoring will look like in the next few years?

Christian: As technology evolves and we continue to move generation closer to the customer, the distribution grid will face new challenges. Large Investor Owned Utilities (I.O.U.) and smaller municipal and co-op utilities will all need better information to safely and reliably operate their network. The future of the distribution grid is leveraging analytics from advanced monitoring solutions to attack and fix problems before they ever occur, eliminating outages and equipment failures from ever happening. And while that sounds like science fiction, we're already capturing precursors that signify faults will occur. The more utilities invest in situational awareness and predicative analytics today, the closer we'll be to living in a world where outages are a thing of the past.

EET&D: Thank you for taking the time to help us understand the challenges of distribution grid monitoring, It looks like the introduction of new, disruptive technologies will transform the ways that utilities make decisions in the future.

GREEN OVATIONS

Innovations in Green Technologies

Mine Your Own Forecast

By Dr. R. O. Mueller, Dr. D. Yenigun, J. Singer

INTRODUCTION TO MINE-WEATHER

Overview

Mine-Weather is an analytical database and visualization system designed to allow companies to probe the accuracy of the weather forecasts they use to plan their activities and preparedness in the case of storm conditions. The tool captures and stores both weather forecast data and observational data for all stations within a given geographical area.

The data is saved at hourly intervals and can be stored for several years, allowing analysis of different types of weather events over a long period of time. As an initial step in the configuration of the system for a specific client, existing historical data can be uploaded.

Background

Weather forecast data play a central role in preparedness and capacity planning for various companies and governmental entities, including electric and gas utilities, transportation companies and transit government entities, investment firms interested in understanding the relationship between a company's infrastructure and their service capabilities under different weather conditions.

> THERE IS LITTLE INDEPENDENT EVALUATIONS OF HOW GOOD SPECIFIC WEATHER FORECASTS ARE IN THE FACE OF DIFFERENT TYPE OF WEATHER EVENTS IMPORTANT TO A SPECIFIC COMPANY

Many of these companies have a critical need to know the forecast or how bad the weather will be 1-3 days out, 3-5 days out and in some cases even longer time horizons are important, out as far as 10 days.

Weather forecast services provide the information companies use in their internal planning exercises. But generally there is little independent evaluations of how good specific weather forecasts are in the face of different type of weather events important to a specific company.

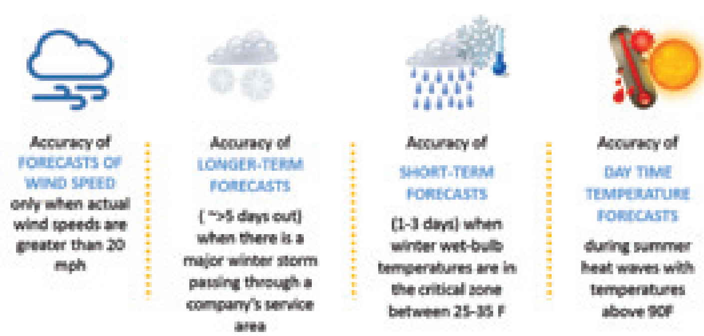
Mine-Weather provides the framework for companies to perform their own independent analysis on the accuracy of weather forecasts they rely on, and to do that evaluation for the specific types of weather events that are most important to the client. We give examples of those types of weather events below.

So the critical issue is not what the overall weather forecast accuracy over a season/year, but rather how good is the weather forecast data for the event types most important to a specific company. The data quality of the forecast for a specific weather variable and within certain ranges of a weather variable (for example for wind speeds above 20 mph only).

Mine-Weather allows clients to segment out the specific time periods and weather variables of interest. They can then probe the accuracy of the forecasts for these specific segments. Since the data is all stored in a deep analytical data zone, these segments can be re-defined as often as needed to answer the important questions of the day.

Applications

The Mine-Weather system provides an analytical data zone for evaluation and verification of weather forecasts for many critical needs.



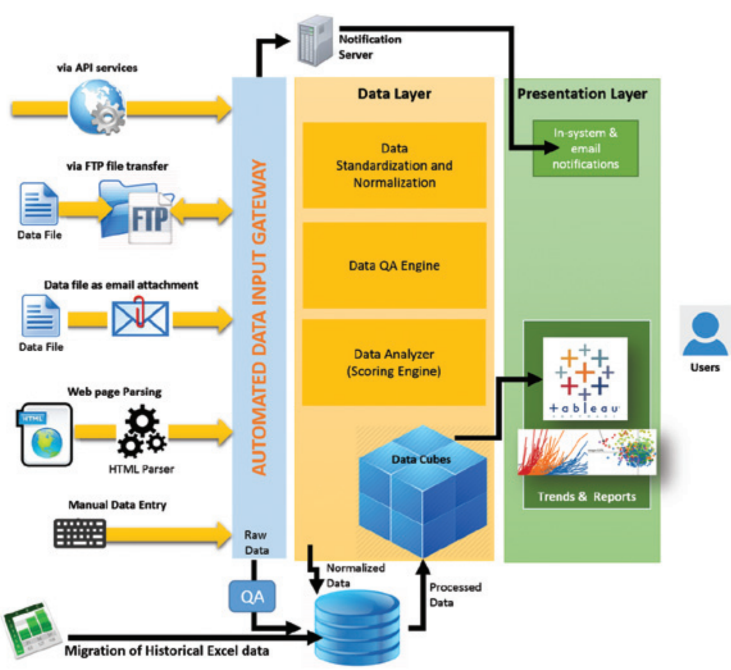
There are a myriad of other applications depending on the company's specific need. Upon detailed analyses, companies will gain insight on specific usage of forecast data may be inappropriate or detrimental since they may find that the accuracy of the data is just not good enough to be useful.

Companies need a flexible analytical data zone for independently probing the accuracy of their current forecasts in all of these situations, and for quickly visualizing the data and results and preparing a report for manager's review.

MINE-WEATHER PROVIDES THE FIRST CLOUD-BASED PLATFORM FOR PERFORMING CRITICAL FORECAST ANALYSES.

Infrastructure

Mine-Weather is a cloud-base application, residing entirely in a Microsoft Azure private cloud arrangement we set up for each client. So the entire capability of Mine-Weather is accessible to a company via an analyst's PC. The private cloud arrangement provides high levels of security and reliability for both the data as well as the analytical framework that is used to store the many different analyses performed by a client.



Mine-Weather is flexible to accommodate client needs and to allow for significant upsurges in usage during certain periods of time. Costs for the service are usage-based.

Macrosoft will work with a client to implement automated processes for capturing all of the weather variables provided in a client's weather forecast services, including capturing the text data that may be included with each forecast. We can utilize text parsing programs for selecting and interpreting information from the text. We capture all the individual forecast provided each day.

Mine-weather data inputs include individual forecasts with 1-4 'future' days of hourly-level forecasts followed by 4-6 'future' days of daily forecasts.

Likewise, we capture all the observation weather data from all the stations in the client's service area. Again, we work with the client to set up automated processes for ingesting all of the actual data. Normally this data is input on an hourly level.

Most forecasts include a wide range of weather variables at different levels of granularity, and we strongly recommend linking them all to Mine-Weather. The ones of particular interest will likely change over time, and having them all in the data base from the start, makes them all available to the client down the road.

Start-up Process

Working with a client, the company develops automated upload processes for interfacing all of the client's current data forecasts and actual observational data from all the stations available to the client. Additional forecasts and stations can be added easily at any point in time. Raw data is saved in the data store, and is always available for later analyses as new questions and issues arise. Mine-Weather system's strategic benefit is that all of the client's weather forecast and actual data is for analysis at all times.

A NUMBER OF STANDARD SCORING MODELS ARE ALREADY AVAILABLE WITHIN MINE-WEATHER

Macrosoft works with the client to implement a 'starter set' of scoring models they are interested in for evaluating their weather forecasts. A number of standard scoring models are already available within Mine-Weather, so clients can start with that set.

THE COMPANY WORKS CLOSELY WITH THE CLIENT TO MAKE SURE THE DATA PROVIDED IN THE FEEDS IS NOT 'OVER-INTERPRETED' OR 'OVER-EXTENDED'

New models may involve selecting the specific new weather variables needed for scoring, and the specific scoring formulas. Since all of the data in the input forecast and observation feeds are already linked to the system in the back-end, the only new work involved is to drawn that new additional weather variable into the analytical framework section of the system. Then, based on this information, we implement a process for creating new summary tables of the weather variables of interest and the scores associated with them. There may be multiple summary tables generated for viewing the data.

The firm works closely with the client to make sure the data provided in the feeds is not 'over-interpreted' or 'over-extended', that is we recommend to never add data where it does not exist. For example, if forecast data is available only on a 6-hour time frame, we recommend only comparing the forecast with the actual data and calculate scores for that individual hour each 6-hour interval. In this example, we recommend not to repeat the forecast data for all 6 hours between forecast values and calculate scores with the actuals for all these intermediary hours. That would be an example of 'over extending' the forecast data.

Many examples of these types of data nuances occur in the process of setting up a new client and we work thru each one with the client to ensure the scores are accurate and meaningful.

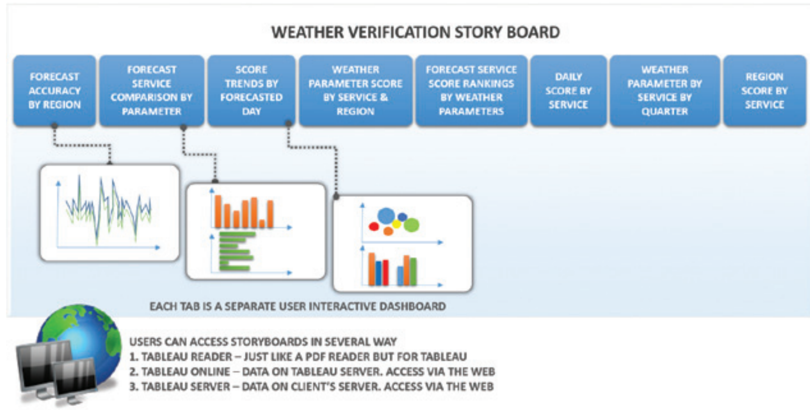
AS EVENTS UNFOLD FOR A CLIENT, THE ANALYST CAN PROBE ANY ASPECT OF THE WEATHER DATA MADE AVAILABLE THRU THE SUMMARY TABLES.

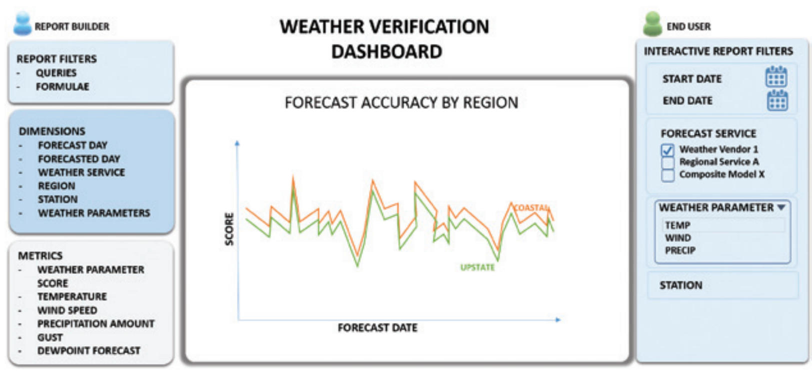
Mine-Weather Dashboards

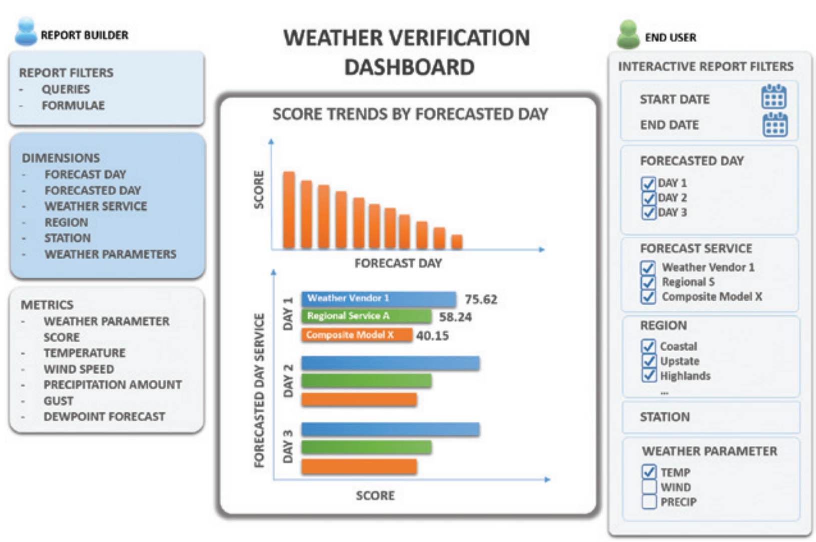
The client analyzes the results using an analytics dashboard implemented using Tableau-cloud. The client can use all of the dimensions available in the summary tables (hour/day; location within service area, all the weather variables, all the individual forecast service, other dimensions as available in the data sources) to drill down and filter/group the score results. As events unfold for a client, the analyst can probe any aspect of the weather data made available thru the summary tables.

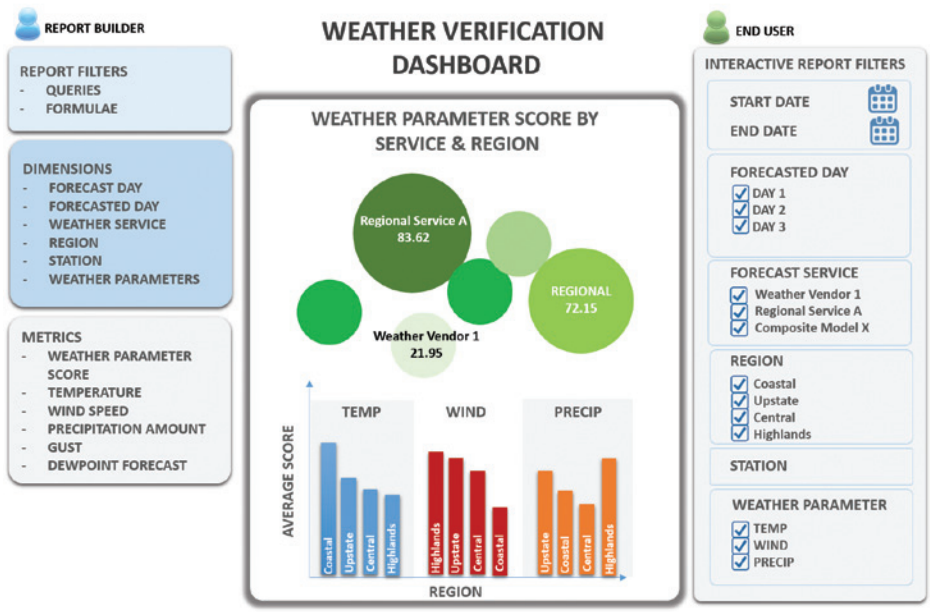
As the questions become more complex and a client gains familiarity with Mine-Weather, additional weather variables and composite-calculations of several weather variables together can be brought into the summary tables for viewing in the dashboard. More sophisticated scoring functions can also be implemented.

The initial setup of Mine-Weather for a new client normally takes a few months, depending on the number of feeds and the level of automation available for each forecast service and the number and level of automation of the weather station data. Additional factors defining the initial setup period are the number of summary tables to be set up and the number and complexity of the scoring algorithms to be included.









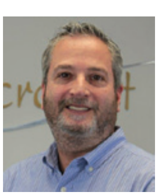
In addition to the analytic dashboard, we provide each client with a web interface for overseeing the processing of data through their system. In particular, the reports include status of all forecast feeds and all station feeds, along with measures of the consistency and reliability of the feeds. For example if actual weather data for a specific weather station is off line for a week, that will be noted in this report.

If the data for a particular station is below a pre-set threshold level (for example, data availability below 75%), we can exclude that data source from the summary tables for the period in which the data is not consistently available. We incorporate these client-defined reliability measures on each feed as part of our implementation process. There are a number of these admin functions that are incorporated into Mine-Weather and need to be configured during the startup period.

About the Authors

Dr. Ronald O. Mueller is CEO and Founder of Macrosoft, Inc., an enterprise software company in Parsippany, NJ. Macrosoft has proprietary software products including Resource-on-Demand software for electric utilities. Ron has a career-long passion in ultra-large-scale data processing and analysis including: predictive analytics; data mining, and AI. Ron has a Ph.D. in Theoretical Physics from New York University.

Dr. Demirhan Yenigun is CEO of Metrica Group, he has 30 years of leadership, strategic thinking & accomplishments in implementing analytical solutions for Fortune 500 companies. Demirhan is the Industry Advisor and Adjunct Professor of Data Analytics and Data Mining at Decision Sciences Department of GWU Business School. Prior to founding Metrica Group, Demirhan held executive positions at Wilson RMS, DomainGo, Macrosoft, Bell Laboratories and AT&T.



Jason Singer has been the Director of Macrosoft's Utilities Practice since May 2005. Jason manages all aspects of Macrosoft's utility portfolio including Resources on-Demand, Assessments on-Demand, Outage Central, and Mine-Weather. Jason works closely with dozens of major utility clients to delivery technology solutions that solve emergency restoration challenges. Jason earned a bachelor's degree from Rutgers University.

From Research to Action

Developing a Strategic Architecture for Utility Telecommunications

By Christine Hertzog and Tim Godfrey

Today's power grids can't run without reliable, resilient, flexible, and secure telecommunications (or telecoms) networks. The intelligent devices that monitor and control the flow of electricity on high- and low-voltage grids require real- and near-real-time data transport capabilities. While advanced grids can provide increased situational awareness to their operators, they require granular network management capabilities, like those provided by telecommunications, to then modulate data traffic priorities based on dynamic conditions.

And just as telecom network expectations and demands are increasing, the old standbys for utility network telecommunications—such as copper phone lines—are disappearing. The result is the need for two equally sophisticated infrastructure investments—one focused on the transport of electrons for the delivery of electricity, and the other focused on the transport of data about the delivery of electricity.

Over the next two years, the Electric Power Research Institute's (EPRI's) Telecommunications Initiative will address a number of questions utilities have about these dynamic telecoms networks, including:

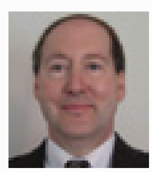
- What tools will we need to manage complex, heterogeneous, and mission-critical telecom networks?
- How do we migrate from today's networks and legacy equipment to telecom networks that support often ambiguous future data transport needs?
- What are the best approaches for migrating from serial- to packet-based telecommunications infrastructure?
- What are the options for the most cost-effective and efficient use of different categories of spectrum (licensed, unlicensed, and shared)?
- What broadband services can be leveraged at the grid's edge?

To tackle this research, we collaborated with our member utilities to establish six subgroups within the initiative, each focused on a specific topic. The ultimate goal is to aid utilities in planning their future telecom networks by developing a "Telecommunication Strategic Architecture and Roadmap Decision Tree" and a "Telecom Planning Framework" document. The goals, while ambitious, are achievable because there's significant truth to that old saying, "two heads are better than one".

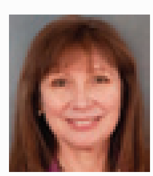
All research tasks and results will be shared through a series of workshops and webcasts, and through reports. The next workshop is scheduled for early October. Hosted by Ameren Corporation, the agenda will focus on task progress and results in development of a communication architecture framework, teleprotection pros and cons using MPLS and carrier Ethernet, a taxonomy of wireless options, and other initiative topics.

EPRI will provide periodic updates on the progress of the Telecommunications Initiative through a series of articles between now and the end of 2017. We invite utilities interested in this mission to join us in this collaborative effort.

About the authors



Tim Godfrey is a technical executive with the Electric Power Research Institute, specializing in telecommunications. He manages the Telecommunications Initiative, a research project addressing the key challenges utilities face related to the telecommunications infrastructure supporting the smart grid. He holds a BSEE from the University of Kansas and has worked in the area of wireless networking and communications for 20 years. He has 23 granted patents. Mr. Godfrey has participated in IEEE standards development since 1994. He is the chair of the IEEE 802.24 Smart Grid Technical Advisory Group, and the IEEE 802.16 GRIDMAN Task Group.



Christine Hertzog is a technical advisor for ICT and Cyber Security at the Electric Power Research Institute. She was previously the founder of a consulting firm focused on smart grid ecosystems and has an extensive telecommunications background. She authored the *Smart Grid Dictionary*, and co-authored *Data Privacy for the Smart Grid*. She has also served in an advisory capacity to innovators, industry associations, and publications. She has an MS in telecommunications from the University of Colorado, Boulder.

Protection and Control System Impacts from the Digital World – Part 1 of 2

By Stefan Meier and Steven Kunsman

Introduction

Gone are the days of the simple electro-mechanical relay without firmware and communication interfaces. The fact exists that protection and control systems have changed significantly in the past decade and will continue to change with technology advancements. The digital world has impacted the protection system from the introduction of microprocessor based relays in the 1980s to protection relays with communication interfaces in the 1990s. Today's advanced digital protective relays utilize high speed communication to replace copper wires for inter-bay control, safety interlocking and even breaker trip and closing. Modern sensor technology also allows for the digitization and analog acquisition in the switchyard replacing hazardous inductive CT and PT circuits with process bus communications.

The Digital World has brought many benefits but also introduces challenges. This paper will focus on the impact of the protection and control system as a result of microprocessor relay introduction in the 1990s. It will discuss key issues the protection and control engineer has encountered in the past and will face with the deployment of the advanced protective relay. Key areas discussed will be performance and benefits including the digitization and transfer function of Nonconventional Instrument Transformers, security threats and best practices for the protection system, fleet management in the age of NERC PRC/CIP regulations and performance consideration to achieve high availability of the protection and control system. As well the paper will address some protection issues such as; since fiber optic current sensor systems have no iron, and no CT saturation, the differential relay need not have multiple slopes to account for CT performance, just a minimum pick up thus increasing the sensitivity several fold.

The educational benefits to understanding these impacts is paramount in the adoption and embracing of modern monitoring and control systems. Understanding the requirements to improve the performance of the substation automation protection and control systems is the goal to create the informed decision maker embracing these advancements in new technology which from a reliability perspective can greatly improve the overall power system performance.

1. Background

After the introduction of microprocessor based relays in the 1980s, the change to protection relays with communication interfaces in the 1990s had relatively little impact on the protection systems as such, but enabled integration of protection devices into substation automation protection and control systems.

Although the introduction of IEC 61850 standard opened-up opportunities for improved integration of protection and control relays of different vendors into automation systems, it had very little or no impact on the protection functions itself. Only now by extending the application of the same standard to the process level for data exchange between the primary system and the protection and control IEDs (intelligent electronic devices), it starts to play a mission critical role in the power system protection. The Digital Substation solution's key technologies (relays, advanced substation automation and modern instrument transformers) are the advantages where IEC 61850/ Ethernet are positioned as technology enablers and not obstacles.

2. The Standard – IEC 61850

First multifunction microprocessor relays were developed in the early 1980s. One was based on the Washington State University Master's Degree Thesis by Ravi Iyer. He joined Brown Boveri Corporation under the mentorship of Stanley Zocholl to design the distribution protection unit becoming the first multifunction microprocessor relay in 1984. This relay performed three phase and ground instantaneous and time overcurrent protection, multi-shot circuit breaker reclosing and integrated per phase metering in a single device that was slightly larger than two single phase electromechanical overcurrent relays. The innovation of the modern digital system roots from this era by the industry pioneers understanding the interworks of the electro-mechanical relationship to engage the revolutionary computer scientist replacing induction discs and spring constants with data acquisition, digital conversion and four point algorithms. These early devices were based on 8-bit microprocessors and programmed in highly optimized assembly source code as the algorithms had to be extremely efficient and program memory size of 64 kilobytes was a luxury.

The microprocessor relay is our industries first venture into The Digital World and it has revolutionized our protection and control systems. The key benefit of the microprocessor relay has been the significant reduction of panel space required to accomplish the same protection system. Figure 1 depicts a line protection system for 1 ½ breaker arrangement.

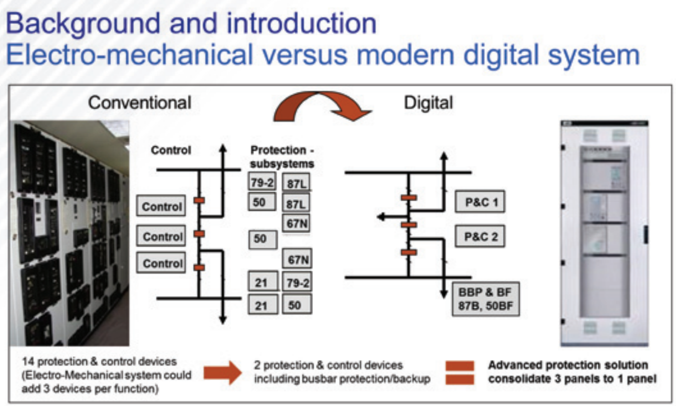


Figure 1: Substations secondary systems showing the same application with electro-mechanical relays versus modern digital system

In the Figure 1 example, the protection function indicated by the ANSI relay elements were traditionally implemented utilizing discrete relays requiring several relay panels to protect this scheme. The utilization of modern multi-object (protection of more than one primary apparatus) relays and open standards for device to device communications allows for functional consolidation, elimination of control and interlocking copper wire interconnections greatly improving the system performance while increasing both reliability and personnel safety.

The most significant change, good and bad, was the introduction of software systems to perform these system protections. Early implementation had limited software source code as the microprocessor power and memory size limited the amount of functionality permissible. As the multi-functional relay advanced and started communicating to RTU and gateways, the complexity of the device software system also increased. The good is that protection system performance increased tenfold while the bad was the introduction of the undocumented feature also known as software bugs. The firmware version management is now a crucial element of the utility fleet management to ensure that the installed protection devices do not lead to unwanted system performance. For the American Bulk Energy System, the North American Reliability Corporation (NERC) has developed a set of reliability and critical infrastructure protection standards to support overall grid reliability, stability and security.

The protection and control system may seldom be called upon to operate until the abnormal condition threatens the apparatus. It is this instance that the system must operate to protect the utility assets. A major benefit of the modern protection devices is the advanced self-diagnostics and self-supervision to ensure the highest availability of the system. Electro-mechanical and solid state relays were only found to be non-operational when a fault occurred resulting in a misoperation or during routine testing. The modern protection device has advanced diagnostics to ensure performance or indicate of pending problems.

Today, the digital world continues to morph as modern primary apparatus embeds digital technology and the benefits of non-conventional instrument transformers further improve system performance and personnel safety. These enablers on the primary system process level will continue revolutionizing the next generation of system protection, control and automation.

3. The Digital Systems

In the digital system, sampled analog values are communicated according IEC 61850 9 2 from merging units or non-conventional instrument transformers (NCITs) to the protection and control IEDs and trip commands are sent as IEC 61850 GOOSE messages to the circuit breaker interfaces. By this, the communication system becomes a critical part in the fault clearance chain affecting the total fault clearance time of the protection system.

4. From copper wiring to process bus

Approaching the installation of a process bus communication network, which connects the bay level equipment like protection and control IEDs or metering devices to the merging units and breaker IEDs located at process level, is motivated by different aspects:

4.1. Increased safety

Every copper wire in a substation is a potential risk whether it is from a CT or PT circuit or a 125V DC control wire. The highly inductive current transformer secondary circuit poses the largest safety concern. The hazard results when an energized current transformer wire is unknowingly disconnected. From inductive circuit theory, current flowing through an inductive circuit cannot be instantaneously changed from 5 Amps to zero. A quick thanks to Wikipedia; the mathematics $v(t) = L\frac{di}{dt}$ formula implicitly states that a voltage is induced across an inductor, equal to the product of the inductor's inductance, and current's rate of change through the inductor. As the inductance does not change during the open circuit, the rate of change in current from 5 to 0 Amps instantaneously has the derivative (di/dt) resultant go to infinity. Thus, the formula's product voltage is dominated by the derivative blowing up to infinity and produces a very large voltage across the open circuited wires. Related to the substation application, an open CT secondary is equivalent to the inductive current going to zero and depending on the secondary load, arcing will occur as these dangerously high voltages build putting field personnel at risk of serious injury or even fatality and equipment and the substation at risk from electrical fire. Minimizing copper leads to greatly improved safety.

4.2. Less material

Using fiber optics instead of copper cables not only reduces the copper cabling in a substation by around 80 percent, depending on voltage level and switchgear type and layout. It also means less material transport to site.

If conventional instrument transformers are replaces by non-conventional ones, further weight can be saved. An optical CT for a 400kV AIS installation weights about 20% of its conventional (SF6 filled) counterpart.

4.3. Shorter installation time and shorter outage time for secondary system retrofits

Less cables to be pulled, less equipment to be connected and less connections to be tested. This leads on one hand to shorter installation times of new secondary systems, on the other hand it also helps to reduces outage times during secondary system replacements. The outage time in the latter case can be reduces due to the shorter time required to install the new equipment, but also because the new equipment comes from the factory fully tested from SCADA through protection and control IEDs to process interfaces. Hence testing of the new system that requires outages is reduced.

5. Fault clearance times of digital substations

When approaching to use NCITs and Ethernet communication to transfer mission critical analog and binary data for protection functions, the tripping speed does not depend anymore only on the protection IED and tripping relays. In digital systems, the fault clearance time is depending on the performance of all involved electronic components like NCITs, merging units, protection IEDs and breaker IEDs, as well as on the design of the process bus communication system.

The expectation on the digital system is that they fulfill today's specifications and regulations regarding fault clearance time and that they perform at least as good as today's protection systems. A typical figure for fault clearance times under normal conditions (without failures in protection system or circuit breaker) is four power cycles. Two cycles are considered for the circuit breaker opening with extinguishing of the arc and two cycles are assumed for the protection system. These figures can be found in international standard like IEC 60834 [3] and national regulations like NERC's technical paper on protection system reliability [6] or National Grid UK's grid code [5].

Two of the times in the above figure are defined and categorized by international standards. The 'processing delay time' of NCITs and merging units is defined in IEC 60044-8 [12] as rated delay time, which shall not exceed 3ms for protection applications. The 'Transfer time' definition is part of IEC 61850-5 [9]. For both, sampled values and trip commands sent via GOOSE, the highest transfer time performance class applies, which shall be 3ms or less. The transfer time is the sum of the times required by the stack of the sending device, the stack of the receiving device and the communication system. According to IEC 61850 10 [10] and IEC 61850 90 4 [14], the 3ms are assumed to be split 80 percent to the processing times in the IED stacks (2.4ms) and the remaining 20 percent (0.6ms) for the communication network.

Table 1 Overview of the standard or typical timings in the fault clearance chain, as well as the timings that are achievable with modern devices and appropriate communication system design. The IED logic processing time, ie the time required by the protection algorithm is assumed to be one 60Hz power cycle in both cases.

Step		Standard	Standard or typical time [ms]	Today possible time [ms]
NCIT/MU processing delay time	$t_{NCIT\text{-}MU}$	IEC 60044	3.0	0.8
Network transfer time (sampled values)	t_{b1}	IEC 61850	0.6	0.4
IED stack processing time	t_{a1}	IEC 61850	1.2	1.2
IED logic processing time	t_{Logic}		16.0	16.0
IED stack processing time	t_{a2}	IEC 61850	1.2	0.6
Network transfer time (GOOSE trip)	t_{b2}	IEC 61850	0.6	0.3
BIED tripping time	t_{BIED}		7.0	4.0
External trip relay	$t_{trip\text{-}relay}$		5.0	0.0
Circuit breaker opening time (2 cycles)	t_{CB}		32.0	32.0
Total fault clearance time			66.6	55.3

Table 1: Time budget with standard respectively typical times and possible times with modern devices.

One important point in the second column with the today possible times, is that the external trip relay is omitted and the circuit breaker is directly tripped by the breaker IEDs power outputs. But even if the trip relay is in place, the total fault clearance time requirement of 4 power cycles, as mentioned above, can be undercut significantly.

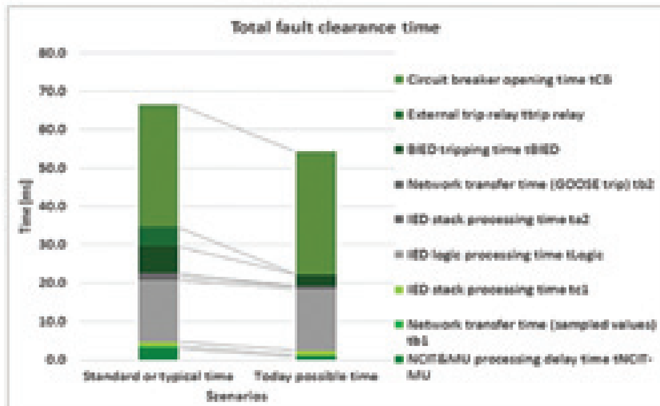


Figure 2: Time budget with standard respectively typical times and possible times with modern devices.

More details on the above used calculation scheme, as well as more in depth explanations and analysis can be found in [2].

6. Impacts of non-conventional instrument transformers

That non-conventional instrument transformers can provide excellent accuracy of 0.2 percent or better has been demonstrated in various installations, where the NCITs have been connected to IEC 61850-9-2 process bus enabled grid meters. To verify the accuracy of the digital measuring chain, they have been installed in parallel to a conventional metering system. The installation described in [8], showed that after three years of operation the difference of the accumulated energy measured by the conventional and the digital system was at around 0.35 percent. This is not the absolute accuracy but the difference of the two measuring systems, which could be up to 0.8 percent as both systems were allowed to introduce errors of 0.2 percent for current and voltage.

Even better results are presented in [7], which describes two installations with NCITs, process bus and grid meters. Here the observed differences for active energy between conventional and non-conventional systems range from 0.01 to 0.19 percent, far lower than the tolerable error given the accuracy classes of the installed conventional instrument transformers and NCITs of class 0.2 and 0.2s respectively.

6.2. Transient performance

Transient performance classes of instrument transformers play important roles in dimensioning protection applications. The protection performance and transient performance is defined in IEC 60044 and IEC 61869. Instrument transformers standard IEC 61869 is replacing the old IEC 60044 standard. The parts for conventional instrument transformers are already released, but for non-conventional or electronic CTs and VTs, still the old standard has to be used. In both cases they describe the behavior at the secondary interface of the instrument transformers, which are the terminal blocks in case of conventional CTs and VTs and the communication interface in case of their non-conventional variants.

Along with the definitions of IEC 61850 9 2 and also the "Implementation Guideline for Digital Interface to Instrument Transformers using IEC 61850-9-2" [13], commonly known as IEC 61850 9 2LE, the instrument transformer standards hence allow to sufficiently describe NCITs and enable building multivendor installations.

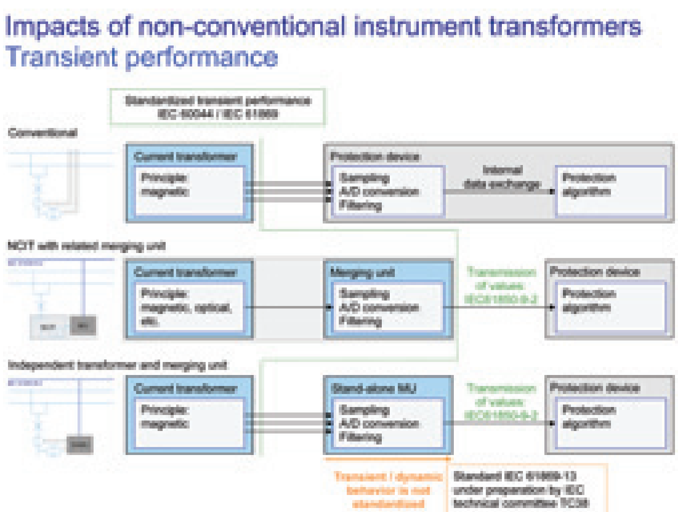


Figure 3: Interfaces and standardization

Until the IEC 61869 standard part is ready, interoperability beyond communication of the stand-alone merging unit of one vendor with the protection relay of another vendor has to be carefully verified. Complete system testing stressing the dynamic performance and transient response of the analog conversion is critical to ensure proper system operation.

6.3. Optimized placing of measuring points in the substation

Thanks to its compact nature, the placement of non-conventional current and/or voltage transformers in the switchyard can be optimized to improve overlapping of protection zones. Figure gives an example of a simplified 1 ½ breaker arrangement with NCITs installed at each side of the circuit breakers. In this setup the protection zones of busbar and line protection as well as the protected zones by the line protection overlap. In case of air-insulated systems, the NCITs can be integrated in the bushings of the circuit breaker or in case of gas-insulated systems; they can be located at each side of the circuit breaker between breaker and disconnectors.

In case of combined NCITs for current and voltage, more voltage measuring points than normal are available in a diameter, which results in biggest flexibility in choosing voltage sources for e.g., synchrocheck and distance protection functions.

6.4. Benefit of sensors not saturating

The result of using a current sensor that does not saturate can have a profound effect on the setting, and thus the sensitivity of a relay. Take for example, the differential relay. A differential relay relies on current sensors to provide the exact reproduction of the primary currents to it for analysis. It then adds the current vectors together and computes a differential current. Then using an operating curve, as shown in Figure 8 determines whether to operate or not. If the differential current falls above the characteristic curve for a given restraint current, the relay operates. If not, it restrains.

The slopes in red section, and green section are there to adjust for the performance of a conventional current transformer. As the restraint current goes up, the chances of two conventional current transformer operating exactly the same reduces. This output difference between the current transformers is compensated for by increasing the slope of the characteristic such that more differential current is needed to operate as the restraint current increases. The red section typically has a slope of 40%, and the green section typically has a slope of 80%. While this compensation is necessary for conventional current transformers to make it secure during current transformer saturation, it has the effect of decreasing the sensitivity of the differential scheme. With the use of non-conventional current sensors, these slopes can be set to close to zero which increases the sensitivity of the differential scheme during high current conditions.

Part II of the article along with all references will appear in the Nov/Dec issue.

About the authors

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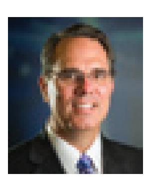


Steve Kunsman is a recognized Substation Automation Specialist with over 32 years in substation automation, protection and control applications, communications technologies (IEC 61850 and DNP), cyber security for substation automation, and the Relion product family of protection and control relays. His ABB career began in 1984 as an Electrical Designer for the protective relay group and has held various engineering, technology and product management positions within the North American and global substation automation organizations. Steve holds a B.S. in Electrical Engineering from the Lafayette College in Easton, Pennsylvania and an MBA in management of technology from Lehigh University in Bethlehem, Pennsylvania.

The Importance of Balancing Operational System Needs for an Evolving Distribution Grid

By Bradley Williams

Electric utilities recognize the need for new distribution network technologies to accommodate customers' growing interest in grid-connected, consumer-owned energy technologies such as solar rooftops, home/building energy management systems, and smart appliances. Left to a natural progression, the technologies will be disruptive to utilities. As policies that concern these technologies—customer choice, emissions reductions, weather-related outage response, and more—begin to unfold around the globe, utilities need to answer fundamental questions: Should they begin to implement new distribution network technologies now, before the demand for grid connection reaches critical mass? Or should they postpone implementation until the trends are clearer?

Utilities can avoid both of these risky alternatives if they instead establish a strategy right now to begin implementing network technologies that serve a dual purpose: solving today's problems, and laying the foundation for incrementally addressing future needs.

Balancing the pace of change

The history of technology is full of tipping points. One day, there's an intriguing idea—a laptop, a smart phone, a streaming video; the next, there's a product no one can live without. Connected consumers and prosumers are driving a number of these tipping points within the electric utility industry. These individuals and businesses desire to take control of their energy choice and want to be digitally connected with their suppliers like they are in other aspects of their life. They want information, control, and options, and they want access and control from wherever they may be.

Electric utilities face a number of consumer-driven tipping points among technologies that connect to the grid and that are owned by consumers and business customers. They fall roughly into two categories:

- *Small distributed energy resources (DERs), such as electricity storage batteries or rooftop solar that can supply power to the grid*. While regulations vary, the global trend is toward requirements that utilities connect both small solar and wind DERs to the grid and use the electricity they intermittently produce as part of their regular power supply to balance load.
- *Smart, grid-connected equipment—home appliances, building-level energy management systems, electric vehicles, and the like—that can play a role in grid reliability as well as in demand response (DR) programs*. DR programs increasingly encompass both large and small customers, and regulators clearly favor programs that use grid-connected equipment to embrace sustainable growth, meet peak demand, decrease supply costs, reduce air pollution, and lower customer bills.

Have technologies like residential solar and EV charging stations reached a tipping point? Most observers would probably say they have not. But both are growing at a rate much faster and being adopted far more widely than expected. Even utilities that at one time never expected these technologies to have much of an impact are now generally wondering when, not if, they will impact business.

Dealing with that uncertainty is a challenge. On the one hand, selecting and implementing those technologies now would be appropriate. On the other, immediate implementation could be seen as imprudent. In the relatively conservative fiscal environment in which most utilities operate, investments in technologies that are never fully used are unacceptable. An intelligent approach to balancing this uncertainty is necessary.

To resolve this dilemma, utilities must re-examine near-term plans for technology upgrades, expansions, and replacements to ensure that all serve a dual purpose. Systems must be able to support both traditional and distributed grid models while also enabling utilities to respond to a wide variety of potential future customer demands.

Five years ago, it might have been difficult to find technologies to accommodate both current and future needs. That is no longer the case. Here are three examples:

Example 1: Distribution Network Modeling

Most regulators assume distribution grid-side resource benefits in the DER rates, and thus it is up to utilities to fully leverage their value in planning and operating models. Distribution network modeling—the ability to see and to profile all utility-scale as well as each customer's granular grid-connected sources of supply (including beyond-the-meter customer DER) and demand, no matter how small—is one obvious example of how utilities can gain that value. Planning functions will need to aggregate these granular resource models to their connected points in the planning models in order to fully accommodate their impacts and leverage them as the grid-side resource they are typically compensated for.

Present

Hidden load visibility: Because most utilities have little visibility beyond the meter they only see the net of the load from DER production. When distribution switching is required, they will find the "hidden load" (the load being supplied by customer DER) must be accounted for, because when there is an outage, all DER trips off (per IEEE 1547) so as not to feed back into the distribution system for crew and public safety reasons. Switching steps must make assumptions regarding the amount of hidden load or risk tripping the line on overload.

Future

Load shifting: As DER proliferates, the need for detailed network modeling escalates. Profiles of each DER device help grid operators accurately predict generation based on variables like time, weather, and condition of the equipment. Similarly, profiles of equipment enrolled in DR programs can help utilities reduce overloads or mitigate voltage violations in the precise places and amounts needed. If permitted, the utilities can also offer incentives for DER and DR enrollment that can ease bottlenecks and further maximize efficiency while reducing the need for emissions-plagued generation. This is part of the vision of a future transactive energy market being discussed in New York, California, and other regions.

Example 2: Outage Management

A solid outage management system has clear benefits. It increases customer and regulator satisfaction by shortening outage times and improving SAIDI, SAIFI, and other reliability indicator scores used around the globe. It gives accurate restoration times to help customers plan around the outage. It quickly integrates mutual aid crews. And, with the addition of advanced distribution management functions, it can automatically isolate an outage and temporarily restore power to surrounding areas.

Present

Alarm management: To maximize the effectiveness of decisions that occur during service disruptions, an outage system must first be capable of providing a view of the entire distribution network model—all the way to the customer smart meter. By doing so, dispatchers can harness more AMI-based outage and restoration alarm-related data from across the network, including geographic information system (GIS), customer information system (CIS), advanced metering infrastructure (AMI), supervisory control and data acquisition (SCADA), mobile field operations, and more. Additionally, by adding a data analysis intelligence layer between field signals and operators, the system can aggregate data into an event, correlate it, and determine what activities are of the highest priority and benefit.

Future

Islanding and Microgrids: Looking ahead, the same principles apply—the outage system must harness a range of data and resources across the entire distribution grid. It must then aggregate that information and present it with operational context so that outage management personnel can determine a prioritized way to more quickly restore power to customers.

With the addition of substantial DER, the ability to aggregate and prioritize could eventually evolve into islanding, which permits a utility to isolate parts of a grid and power each individually using local solar gardens, batteries, and back-up and rooftop generators. Isolation continues until the utility reverses the process, protecting field personnel and equipment from power flows within the islanded microgrid.

Similar to effective alarm management, islanding requires accurate visibility of the distribution grid combined with intelligent data management. Utilities must know the supportable load for each DER under a wide range of conditions. In most cases, they will also need the profiles of all power-drawing equipment available for cycling so that they can balance supply and demand within the island. Islanding will permit power sharing during an outage; for instance, an industrial park that owns substantial DER might use its own islanded resources during the normal workday, then power surrounding neighborhoods at night. The partial or periodic power flow available through islanding can significantly lower the negative economic consequences of widespread or prolonged outages.

To maintain safe and reliable operations, power-system analysis can identify if protection and control systems may be at risk under islanded conditions. This could also include near real-time assessment of potential islanded microgrid instability when there are insufficient spinning inertia resources to support high inertia loads (such as air-conditioning and heat pump compressors.)

Example 3: Smart Field Device Management

Traditional asset management systems handle a relatively limited number of specifications: manufacturer, serial number, maintenance schedule. Smart equipment, however, requires a far greater number of specifications: tables to support configuration compatibility, calibration measurements, firmware versions and patches applied, scheduled battery replacements, audit compliance that can grow to support millions of devices for large utilities.

Present

Smart field device management: Manually (or building a one-off spreadsheet/database) tracking even a few smart devices quickly becomes chaotic. Chaos grows exponentially as more smart equipment comes on line.

Given the growing numbers of smart devices on utilities' near-term roadmaps, a smart device asset management system that provides a registry specifically to handle smart devices is easily justified. Since many of these devices support two-way communication with smart equipment (including the Internet of Things), a smart device management system can be leveraged to support automated processes for firmware updates and configuration changes. Additionally, the system provides an audit trail for device activity, recording those device-level configurations and related communications.

By using the device registry to manage configuration and commands, firmware upgrades become simple and low cost. Proactive adjustment and maintenance also ensure the device life is optimized. And when combined with analytics, this asset registry becomes a system for predicting and preventing asset failure and operational risk.

The same applies to beyond-the-meter consumer energy technology devices that utilities need to model and interact with (such as load control transponders, rooftop PV and inverters, EV smart-charging, battery storage, smart thermostats, home energy management systems, etc.).

Utilities need a device registry and lifecycle management process and systems to order to engage customers and fully leverage these grid connected resources.

Because most traditional asset management systems don't support this field device management function, utilities can add this registry by implementing integrated smart-device management systems or choose to incrementally add with existing smart grid projects such as AMI/MDM.

Future
Value-based services: In a future in which utilities offer multiple programs involving customer-owned equipment (or allowing third-party providers to do so), a smart device asset management system becomes imperative. The utility will need the system to support scalable data management processes required to support the exponential growth of sensor-based devices. Smart device management will facilitate very sophisticated outage, distribution, DER and demand management programs. Imagine, for instance, utility control of a 50-percent saturation of smart thermostats. Coordinated cycling is a perfect fit not just for today's demand response programs—required for just a few days per year—but also for demand programs that use smart appliance cycling as a way to balance load 24/7.

A Way to Move Forward

Making sure that current technology investments meet both current and future needs requires a considerable strategic vision of the future utility. Utilities need to ensure that today's technology selections and upgrades act as a stepping stone to support the programs they want to offer and expectations of future customers. A decision today to invest in one-off, limited-use technology, or to contract with third-party service companies, could significantly increase the technology costs to offer new programs or support new business models in the future.

In contrast, investments in technologies that align with a strategic vision of the future utility will provide current and future benefits, including:

- Preventing dead-end investments in applications that will clearly need to be changed out in the future.
- Giving staff time to gain experience with new procedures and business processes while there is still a relatively small amount of customer-owned energy technologies, DER and DR on a system.
- Lowering the cost and risk of pilot programs. Planners can have a fully tested, real-life technology structure within which to design, offer, and evaluate the results of a wide variety of possible offerings. They can gain experience not only with the technology itself, but also the business process changes that will inevitably accompany the widespread adoption of DER. And the most successful pilots transition smoothly into permanent programs; there's no loss of momentum while staff members struggle to scale up technologies that work well only when the number of program participants is small.
- Enabling incremental responses to incremental customer demands.

There is, of course, no crystal ball that eliminates the risk of unknown market developments—breakthroughs in equipment efficiency, for instance, or changes in customer behavior that upend the most carefully devised business strategies. There are, however, technology characteristics that can go a long way to ensuring the future value of today's investments. For applications, these include the ability to:

- View – at a granular level to individual distributed resources and their operational context within the network model. The volume of customer-owned equipment and grid edge-connected devices will continue to grow. Utilities will inevitably need to plan for and manage DER impact on reliability and create business models to capitalize on the new revenue and demand response opportunities.
- Scale – to handle not just more customers and more devices but also steeply escalating amounts of detailed information about each customer and each asset.
- Prioritize – to separate activities and processes that must take place in real time from those that can have less rigorous scheduling requirements. Utility staff and other resources are not increasing at the same rate as utility data, devices and processes. Applications that treat equally every alarm, every device reading, or every transaction all but ensure that resources will be wasted and real emergencies will receive short shrift.
- Integrate – to help utilities build a system of systems. Applications must relate to each other in logical ways so that business processes to manage data can flow seamlessly from one to the next given a wide range of possible scenarios.
- Recover – to guard against data loss no matter the severity of security breaches or equipment breakdown. The volume of smart metering data will likely, in the future, seem almost trivial compared with data volumes associated with DER management and grid-connected customer equipment. And grid efficiency will require extensive historical analysis of this data. Once lost, such data cannot be reconstructed.

In short, the most successful utilities will start with a strategic vision of the network technology platform. By filling today's needs with technologies that can incrementally accommodate a variety of futures, utilities carve for themselves a central role as the electric grid changes from one-way power delivery to a complex, multi-directional system of inputs and outputs offering customer convenience, greater reliability, and adherence to emerging international environmental goals.

About the author

Bradley Williams is vice president of industry strategy, Oracle Utilities. Williams is responsible for Oracle's smart grid strategy as well as utility solutions for outage management, advanced distribution management, mobile workforce management, work and asset management, and OT analytics. Williams has spent the past 30 years driving innovation in the utility industry in roles including T&D power system engineering, technology development, asset management, and industry analyst.

Plugging the Industrial Internet into Your OT Architecture: 3 Steps to Leveraging the IIoT in Your Smart Grid

By Adam Reiss

Operational Technology innovation embodied in the Industrial Internet of Things (IIoT) is proliferating at a rapid pace. To date, the electric power industry has not taken full advantage of this sea change. Accenture predicts that IIoT will add $14.2 trillion to the global economy by 2030 (https://www.accenture.com/us-en/insight-industrial-internet-of-things), while experts like Steve Bolze, president and CEO of GE Power, claim that the world will need 50% more power in roughly the same time frame (http://news.mit.edu/2016/ge-joins-mit-energy-initiative-develop-advanced-technology-solutions-transforming-global-energy-0830).

Renewable assets and distributed energy resources are playing an important role for utilities as they seek to meet increased demand; however, leveraging IIoT data and analytics is an equally important, critical component of grid modernization. There are three relatively simple ways to improve upon existing infrastructure and enable use of IIoT technology: first, introduce a Common Information Mode (CIM), secondly, employ a real-time dataflow engine, and finally adopt cloud computing infrastructure.

At present, OT architectures do not provide contextualized event management or actionable intelligence. Typically, OT architectures allow devices to publish only a device ID and device data to a utility's data network. No information about the role of the device or application is included with basic telemetry data. Centralized management via GIS data or a Distribution Management System (DMS) produces limited data. Utilities working to make the most of IIoT technologies must be able to provide data richer than device ID and basic device measurements.

To create more robust data and enable distributed computing, utilities should employ a Common Information Model (CIM). CIMs establish a richer data model that codifies the relationship between data and helps to manage diverse models and naming schemes across systems and devices. CIMs define the semantics of data and use these definitions to establish a unified web of information without the overlaps and conflicts traditionally found in Operational Technology integrations. Exposing consumable data and performing the necessary classifications so that contextualized data is available to the appropriate smart grid application is important; however, utilizing a CIM alone does not create the necessary real-world connection to the virtual world.

When working to establish a real-time analytics program, an existing 'real-world' physical connection, frequently referred to as a 'Y gateway,' must be exploited to create an exposed model. The most efficient way to establish and exploit 'Y gateways' is through the use of architecture designed to do so. LiveData Utilities refers to this architectural pattern as Operational Technology Message Bus (OTMB). OTMB expands upon traditional architectural patterns employed by utilities. OTMB acts as a real-time utility protocol-aware dataflow engine – providing SCADA-class in-memory processing, configuration and manipulation of dataflows at run time, and seamless integrations to IT and OT systems. OTMB architecture pattern is capable of handling diverse datasets from a nearly unlimited number of data sources, homogenizing the various outputs of a utility's stack, which, in turn, allows the data being created to be consumed by a wider variety of systems and applications. The use of these Y gateways established using OTMB architecture allows utilities to share data sets to open source tools like historians or machine learning and analytics engines; this is a critical capability with the growing popularity and rapidly improving performance of cloud computing platforms and infrastructure.

The question of how to implement and leverage IIoT remains. Today, utility asset analysis looks at a small number of cross correlations. The reality is that this approach is outdated and ultimately does not take advantage of existing data already captured by utilities. Utilities need to be smarter about applying cross correlation and other machine-learning techniques across a much wider breadth of grid systems. While utilities are already suffering from a data deluge, data volumes are continuing to grow as new data is stacked upon old data. While a CIM model exposes usable data and elevates data beyond simple timestamp recordings, and Operational Technology Message Bus architecture exploits gateways back to the data network; data in itself is not a resource that creates meaningful, actionable insight – and neither more data nor 'Y gateways' help to manage the data tsunami.

Public or private cloud-enabled computing is a key characteristic of IIoT. By adopting cloud computing infrastructure, rich data analysis can be performed on Operational Technology data – delivering actionable insights without the need for an in-house data scientist. The richest source of actionable insight is via these cloud computing platforms, which have been developed to recognize deeply entrenched patterns that would not be detected by human analysis. Operational technology data with a Common Information Model applied can be queried with the depth and specificity needed to derive actionable intelligence from pattern recognition and other machine-based data analysis.

Ultimately, this enables operators to achieve a deeper understanding of exactly what is happening within the grid, where it is happening, and most importantly, why it is happening. In the past, utilities have been reluctant to employ cloud-enabled solutions because of utilities' unique real-time requirements. IIoT is designed to address real-time requirements, but to take full advantage of IIoT technology, utilities must support architectures that apply cloud-enabled solutions.

We work with utilities across the globe - every utility I work with has a unique collage of devices, applications, databases, Operational Technology and IT resources. The recent proliferation of grid edge technologies has resulted in each piece of the technology collage creating data in its own way – without exposure to other parts of the collage or the data created within those applications and devices. Only centralized computing is possible as a result of this diversity found in smart grid data. Common Information Models not only homogenize application data, but also elevate that data from being basic historian data to being the foundation for operational analytics.

Operational Technology Message Bus architecture and similar OT dataflow engines allow for necessary 'Y gateway' connection to devices, systems, and applications, as well as provisions for OT data hundreds of times per second. Additional benefits of employing OTMB or similar architecture include minimizing total configuration efforts and allowing for partitioning of systems, which is important when managing OT/IT hybrid scenarios found in many smart grids.

As more utilities integrate distributed energy resources and grid edge technologies, a performant architecture, a Common Information Model, and the introduction of cloud-enabled solutions are three additive updates to utility grids that will jumpstart IIoT deployments and ultimately help transmission, distribution, and generation suppliers meet growing demand and optimize current operations. The capability to deeply understand activity within transmission and distribution grids is the very essence of why IIoT is a critical component to modernizing our aging grids.

About the author

Adam Reiss is Senior Marketing Associate at LiveData Utilities, managing the marketing activities for utility products and services. With a background in institutional research that covers everything from investor statements to coral reefs, Adam has a passion for data, and enjoys delivering actionable insights from unlikely sources.

East Central Energy Virtually Shrinks Service Area and Significantly Reduces Fleet Costs

By Robert Dennis

Electricity, always taking the path of least resistance, is efficiency in its simplest form. East Central Energy, as with many electric cooperatives, strives for the efficiency of the very product they provide. The organization had a bright idea to implement a GPS-based fleet management system to improve efficiency by optimizing fleet dispatching with the limited resources available to them across the 8,000 miles of power lines they service.

East Central Energy is a member-owned electric cooperative, formed in 1936, that currently provides electric service to more than 58,000 homes, farms, and businesses in east central Minnesota and northwestern Wisconsin. With a mission to safely provide reliable service, East Central Energy, headquartered in Braham, Minnesota, has equipped over 75 vehicles with GPS Insight to further its values of accountability, innovation, integrity, and its commitment to the community.

Location, location, location

One of the most basic challenges for any organization, regardless of whether or not they are looking to deploy a GPS fleet management solution, is to know exactly where resources are located and East Central Energy was not immune to this challenge. Phil Beaupre, System Control Manager at East Central Energy, says, "We serve about 8,000 miles of [power] line which feeds out to about 58,000 customers. So we have a pretty big footprint. But comparatively our fleet isn't quite as large as it could be and we want to use our resources as best we can." With 14 counties to serve, and a limited fleet size for the coverage area, East Central Energy was very interested in resource optimization, and knowing where their vehicles are located at all times would provide them with the intelligence needed to best manage their fleet.

Outside of efficiency and fleet optimization, a new challenge was discovered when a distress call came into the dispatcher from an unseasoned apprentice. The apprentice did not know where he was, making an emergency dispatch situation extremely difficult. With this clear safety issue, an immediate need for a GPS-based fleet management system was identified. To meet its own heavy safety standards, East Central Energy needed a location system in place to prevent similar scenarios in the future.

Another challenge East Central Energy identified, and wanted their GPS vehicle tracking system to address, was their outage response time. What made this particular challenge a bit tricky is that it would require an integration of GPS data with a pre-existing system. East Central Energy uses a mapping system called MapWise by NISC to visualize their outage data and wanted their GPS partner to be able to populate this outage management system with the locations of nearby crews. Rather than have a dedicated response crew that was dispatched from a central location, East Central Energy wanted to improve outage response time by being able to identify the closest crews in the field to the source of an outage and dispatch them to that location.

Solving the Challenge of Efficiency and Optimization

East Central Energy understood the value of vehicle location but found much more after implementing the GPS solution. While it took many years to decide on a vendor and an appropriate rollout plan for their fleet, East Central Energy did their due diligence and felt that the ease of installation and implementation provided by the partner company was the deciding factor. Even though the decision and implementation were not a part of an overnight process, the goal was met and dispatchers at East Central Energy are now provided with a top-down view of where their vehicles are at any given point, effectively shrinking their 5,000 square mile service area.

East Central Energy Virtually Shrinks Service Area and Significantly Reduces Fleet Costs

The fleet management system provides a consistent experience comparable to familiar internet mapping tools and this was a very attractive feature for East Central Energy. Dispatchers could now identify technicians that are closest to an outage and dispatch them from there rather than from a regional service center that is much further away, greatly improving efficiency. In the same way that electricity finds the path of least resistance, East Central Energy applied the concept to dispatching service vehicles from a closer location rather than a service center that may be further away.

These efficiency improvements resulted in an average monthly decrease of miles driven by the entire fleet to the order of: 14,000 miles, or $3,300 according to AAA's most recent driving costs report. That's a $40,000 annual savings.

With East Central Energy's heavy emphasis on safety standards, they are now able to best respond to emergency scenarios. Distress calls can be processed more effectively and scenarios in which technicians or apprentices who are unaware of their location can be addressed with precision. Gone are the days when an employee reports a stranded vehicle or an on-site injury and the dispatching team is left to wonder where exactly they are located. Dispatchers use the same tool to identify the closest vehicles –vehicles equipped to best handle the emergencies – rather than relying on a central service station.

With better insight into driver behavior, East Central Energy is also able to proactively improve driving habits. The new system provides reports and alerts for speeding, idling, unauthorized vehicle usage and many other driver behavior metrics. East Central Energy is equipped with tools that allow them to improve their driver efficiency and proactively review areas of concern. One specific tool East Central Energy gets plenty of use from is the vehicle history which allows them to replay a vehicle's tracks – often referred to as a breadcrumb trail – ensuring drivers are taking efficient routes to work sites.

Another challenge to East Central Energy's safety standards, and one often overlooked by many other organizations that operate a fleet, is vehicle maintenance. The new system provides a great way to track vehicle maintenance, keeping operations running smoothly and improving safety while reducing associated costs. "We have 5 shops that house equipment and vehicles. Before we head on the road to our districts we can see where the trucks are, if they are close, or at the shop. This way we can schedule work in advance and plan our day efficiently," says Holly Giffrow-Bos, Fleet Supervisor at East Central Energy. Efficiency is key and ensuring all vehicles are on the road, operating as they should, will maintain and improve desired efficiency.

The flexibility afforded by the management system to integrate valuable data across nearly any platform made it a very intuitive and simple process to connect East Central Energy's MapWise data with vehicle location data. By leveraging the robust set of application programming interfaces, or API's, provided by GPS Insight, MapWise is able to seamlessly connect and speak with GPS Insight to provide East Central Energy with the information they require for efficient operations. This added functionality allows East Central Energy to view more data in one place to make better sense of their operations and how best to address their challenges.

East Central Energy has improved efficiency and safety though a GPS-based fleet management tool. Top-down views of overall fleet location make large service areas easier to manage. The ability to manage a limited amount of resources to cover an increased service area, while also ensuring the safety of technicians and the community, is ultimately what lead East Central Energy to implement the system provided by GPS Insight. It's safe to say their bright idea is paying off.

About the author

Robert Dennis is an accomplished marketing leader with over 10 years of experience working with emerging technologies to ensure customer satisfaction. At GPS Insight Robert has a vested interest in customer success and works closely with customer data to continually improve the user experience. Hailing from the island of Puerto Rico, Robert now calls Chandler, Arizona his home.

Avoiding the Pitfalls of Data Acquisition

Big Data, Little Data and Everything in Between

By Matt Karli

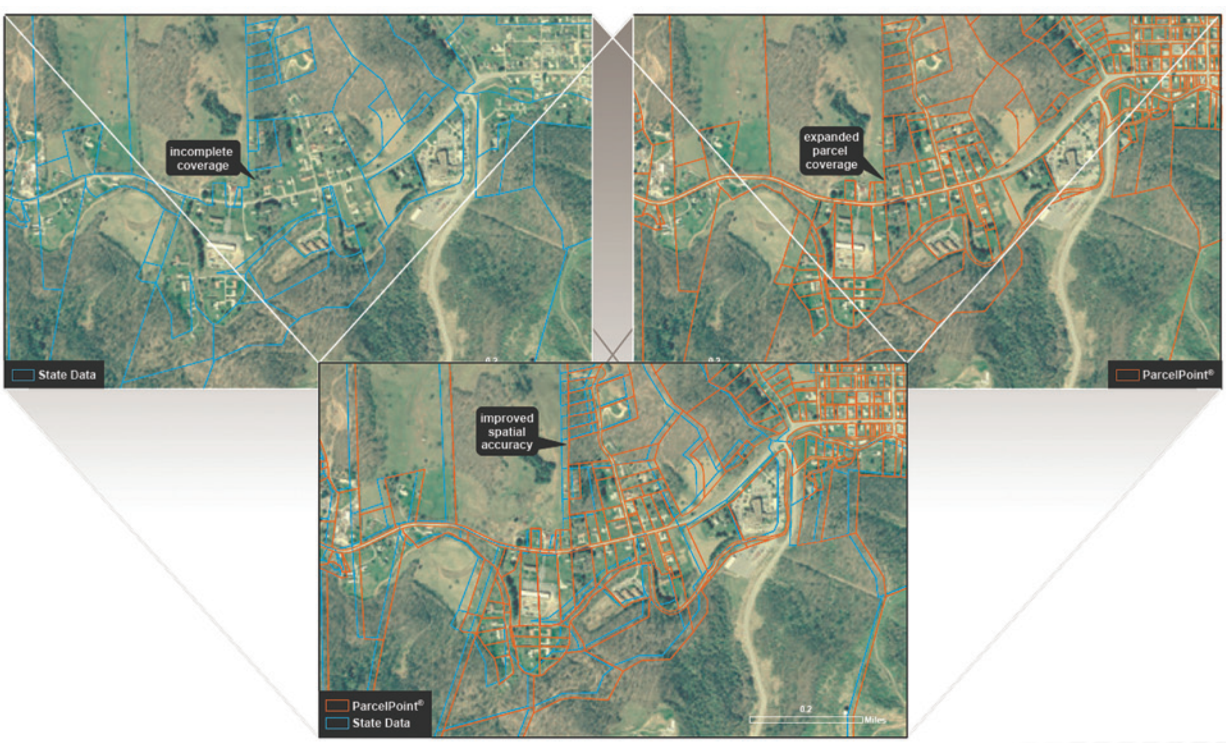
In today's world, data of all types are used to drive decisions within organizations. Those who ask the right questions, and have the right data to provide answers, often find themselves with a significant advantage over the competition. Solid data assets are essential to ensure you have the right support in answering these questions, whether we are talking about "big data," "little data" or content of another kind. As part of their business strategies, many organizations seek to leverage content that has been previously created or managed by others. Third-party data acquisition can save significant time, and in many instances, expensive labor. Pitfalls however, do exist. I have managed data acquisition efforts related to geospatial content within my organization for nearly 10 years. Here are some of the best practices I have learned during that time in order to avoid common pitfalls that may be encountered when exploring third-part data acquisition.

1. Define Your Purpose

Before you ever consider any manner of data acquisition strategy, you must first define the question, or questions, you are trying to answer with the data you are looking to acquire. Without clearly establishing the purpose for which you are setting up a database, frustration ensues as you will often find your data lacking in either data wholeness or data architecture. By establishing the "why" behind your data request early on, you will be able to successfully answer many of the inevitable questions that will come up along the way. This exercise can often be one of the most difficult activities in preparing to move forward with your acquisition plans, and can often take more time that you initially expected. Beginning with a clear purpose is critical to the initial and ongoing success of your endeavor as it properly positions you for future success.

2. Seek Out Your Sources

Once you have established a firm set of questions, or purpose for which you are setting up your data architecture and structure, you will be in a positon to start seeking sources for your required content. There are many things to consider when seeking data inputs, and many of these factors will be unique to the requirements of your particular use. However, there are some common data quality and completeness items that are relatively universal and should be considered in any acquisition strategy. Early on, you'll want to consider the longevity needed from the data you are seeking to acquire:



- Are you looking to support a brief project that will not require long-term data access, updates to the data and long-term consistency?
- Are you seeking to support a longer-term decision process – one that will last for many years? If so how important is consistency from one iteration to the next?
- If an existing provider, for whatever reason, is no longer able to provide content to you, will that be acceptable? What are the possible alternatives for securing another provider?

All of these issues must be carefully considered when exploring data sources.

3. Ensure Data Quality

Quality can be subjective and is directly related to the use-case behind your data needs. And as quality can be difficult to quantify, understanding the goals you are trying to achieve is critical in order to determine if the quality of the potential content is sufficient for your needs.

My experience with data acquisition has, for the most part, been characterized by the spatial variety or mapping type. When I speak of mapping I am referring to it in the cartographic sense of the word. One of the earliest questions CoreLogic® struggled with on the data acquisition journey was how to express the true quality of the data when it came to positional accuracy. When evaluating the positional accuracy of spatial data many will tell you that the comparison of the data to an aerial image is the best way to evaluate the quality. On the surface this makes a lot of sense, as our natural inclination is to believe what our eyes are telling us; after all, seeing is believing, right? However, as any photogrammetrist will tell you, not every aerial image can be trusted, since a picture, like a paper map, is attempting to represent a three-dimensional world in a two-dimensional space. True mapping grade aerial imagery must be processed though exacting standards to arrive at mapping quality orthophotography. Luckily, the Federal Geographic Data Committee has published a standard for spatial data accuracy which the firm utilized to arrive at a quantitative method for determining the true quality of the data we were acquiring. In some instances, we found it necessary to make significant improvements to the spatial quality of some of our source data. The application of this standard made it possible to apply quantitative acceptability standards for source content from more than 5,000 providers.

4. Ensure Data Completeness

When evaluating the completeness and quality of any type of data you are seeking, it is important to also consider the attributes that will be received as part of the dataset you are sourcing. Some datasets will contain few attributes and some will contain many. Based on the questions you want answered from your earlier determination, some attributes will be more or less important to your decision-making process. Once you understand what attributes are most important for your use, you can seek additional detail from any content provider. One important consideration is the evaluation of population percentages for each attribute type. This will help you to determine if the data that the content provider offers is sufficient for your business needs.

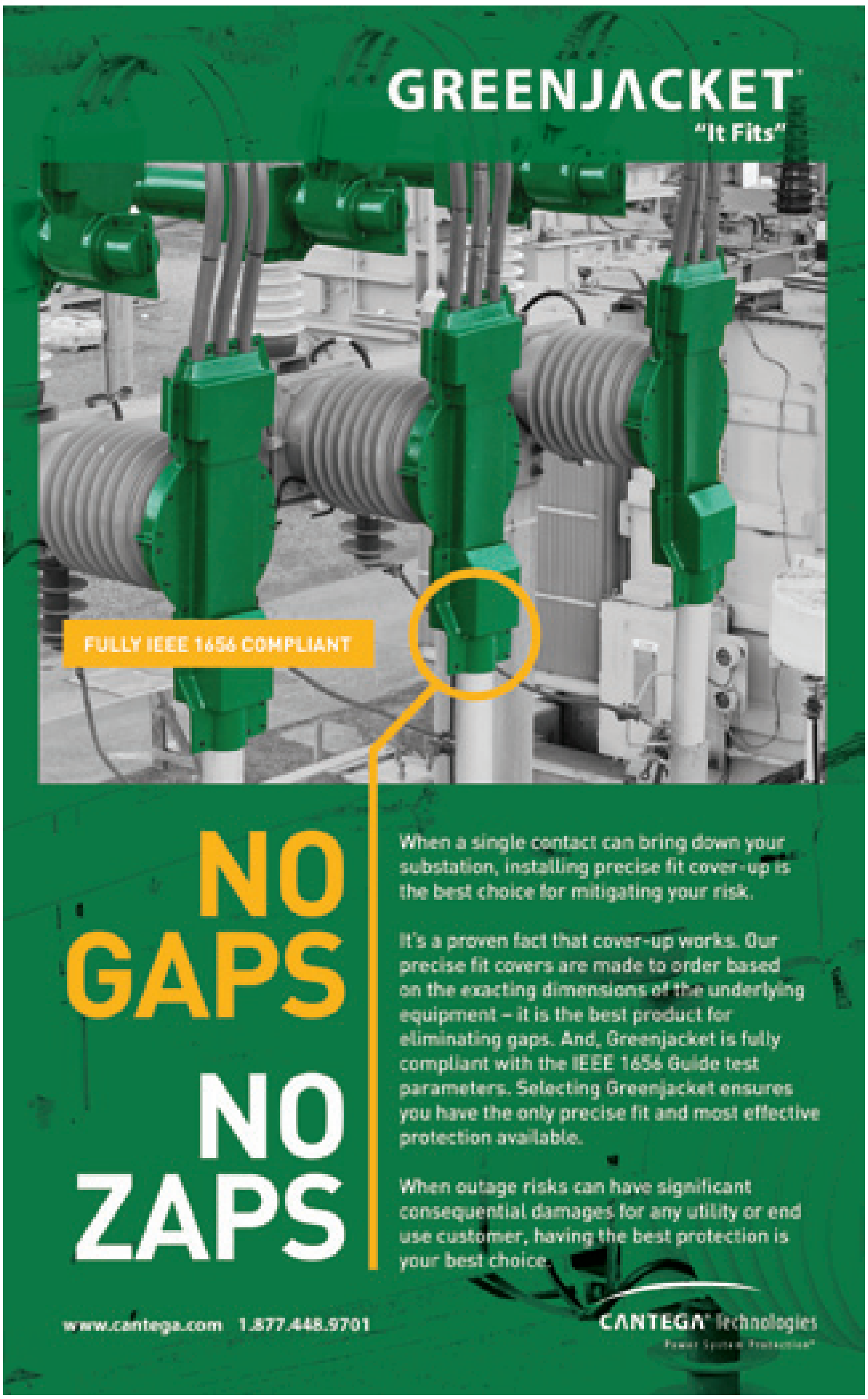
5. Metadata Can Lead to Better Data

An area that is often overlooked when evaluating a variety of content is the quality of the metadata supplied. Metadata is simply additional data about the data or, in some cases, more data. Quality metadata will provide great detail related to the content you are utilizing. Metadata contains such things as manner of data collection/creation, currency of the data, delivered content and contact information related to support for discovered issues, to name just a few. Comprehensive metadata is an indication that the provider takes data management seriously, and with that comes pride in their responsibility to provide you with quality data.

6. Source with Authority

Finally, seeking out an authoritative source for content is what I consider to be the gold standard of data acquisition. Authoritative data is data which is produced by an entity with the authority to do so, such as a local government. In many instances, though certainly not exclusively, this data is authored to support some other need. A good example of this type of data is property tax assessment data created and managed by local governments to manage property tax assessments. Much of my experience with authoritative data is related to data resulting from an existing legal or statutorily requirement to create the data for a particular purpose. The problem with acquisition of this type of data is that it is quite rare that distribution of this content is a core component of the entities' overall mission – they have another purpose they are trying to support. This can make efforts to acquire this authoritative data time consuming and frustrating. Luckily, there is a fallback position. Some entities support internal business activities with content received from these authoritative sources. If properly vetted, these users can become a valuable source of quality content. This is especially true when you consider that these entities likely considered many of the same questions that you, as a data requestor, are asking.

As you can no doubt see, data acquisition is far more complicated than just picking up the phone or plugging a search term into your search engine. A comprehensive data acquisition strategy is important to ensure that time is not wasted. Establishment of strategy helps achieve goals, eliminate ambiguity and speed the time to success of the organization. When you are able to appropriately leverage strong data acquisition practices you can find the balance between what I like to call professional services and the DIY approach.



About CoreLogic

CoreLogic (NYSE: CLGX) is a leading property information, analytics and solutions provider. The company's combined public, contributory and proprietary data sources include over 4.5 billion records spanning more than 50 years. The company helps clients identify and manage growth opportunities, improve performance and mitigate risk.

About the author

Matt Karli is a senior product manager for CoreLogic Insurance and Spatial Solutions. In this role, Matt is responsible for the product management of the suite of location and jurisdictional geographic boundary products.

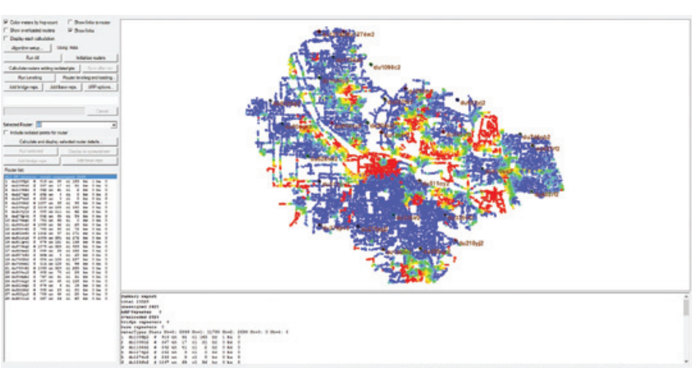
Matt has more than 9 years of experience developing and launching high margin spatial products to the marketplace. He joined the CoreLogic team in 1998 as a Map Researcher for the Flood Services Department. He then transitioned to roles in both Operations and Data Acquisition before moving into his current Product Management role. At his time at CoreLogic Matt has overseen the formation and leadership of the team that created the ParcelPoint® product. He has experience in both product and project management, map interpretation, GIS, quality control, business process improvement, and operations management. Additionally, Matt is one of many patent holders at CoreLogic; he was part of a team that developed a product for unique spatial intelligence and patented that technology.

Matt earned a B.S. in Geography and Planning with a minor in Geology from Texas State University, where he also taught several undergraduate geology labs.

Internet of Things and Solving Latency For an Instantaneous World

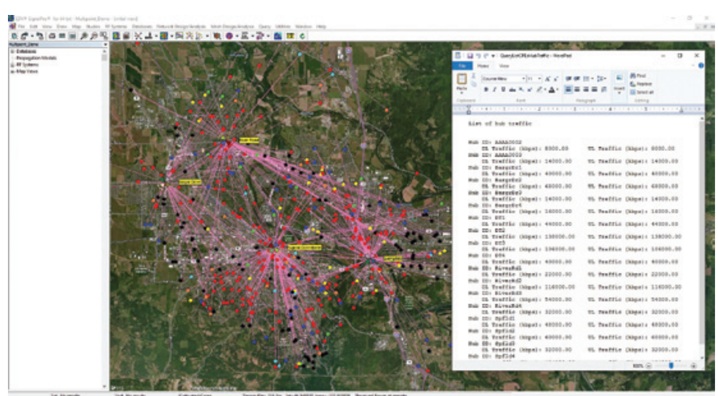
We have all heard about the impending Internet of Things (IoT) revolution. As a matter of fact, such talk has been going on for many years. Even as far back as 1966 when German computer scientist Karl Steinbuch said, "In a few decades time, computers will be interwoven into almost every industrial product." But with Machine-to-Machine (M2M) deployments and several "intelligent" devices already in place... perhaps the IoT revolution is finally upon us. Even so, to a large degree it seems we have adopted an almost passive approach to the design and deployment of IoT networks. We expect bumps in the road as more of these devices are deployed and believe that in the future, best practices will be developed and the devices and networks will become more efficient. While it is certainly true that the technologies will mature over time, we can also take a more proactive approach to the impending IoT revolution and ensure that these systems meet our requirements.

Unfortunately, current system architectures were not designed with the IoT in mind. Not many systems with their current architecture can handle the traffic of a network consisting of millions of devices. Furthermore, when we consider such networks, we must not just think of them as systems consisting of these millions of devices – because with millions of devices - you may very well have billions of packets of data. It is common to think of bandwidth as the primary metric when designing wireless networks and ask the question; "do we have the bandwidth to handle this data?" But as we move to the IoT paradigm, we must take into account much more than bandwidth. Foremost among these factors is latency.



Node connectivity and traffic report

A recent study by Forrester Consulting said that "47% of consumers expect a web page to load in two seconds or less..." The study went on to say that "40% of consumers will wait no more than three seconds for a web page to render before abandoning the site." It is no secret that we demand instantaneous results. We expect an Instagram picture to post immediately, we want a Youtube video to start streaming the instant we click the play button, etc. The IoT will be no different and perhaps consumers will be even more impatient as the IoT encroaches more and more into our daily lives. Would a consumer, for example, be willing to wait for a light to come on after flipping the switch? We expect 'real world' things such as switching on a light to occur in 'real time.' Therefore if the IoT is to be a part of our "real world" we will expect results in 'real time.' Furthermore, we will demand the IoT to help improve and add efficiencies to the daily lives of consumers as well as increasing productivity in business and enterprise – something that will be difficult to achieve if our devices and apps are not responding in real time. And of course, mission critical applications such as public safety, military and disaster recovery will benefit greatly from the advantages of IoT – and these applications must have instantaneous results.



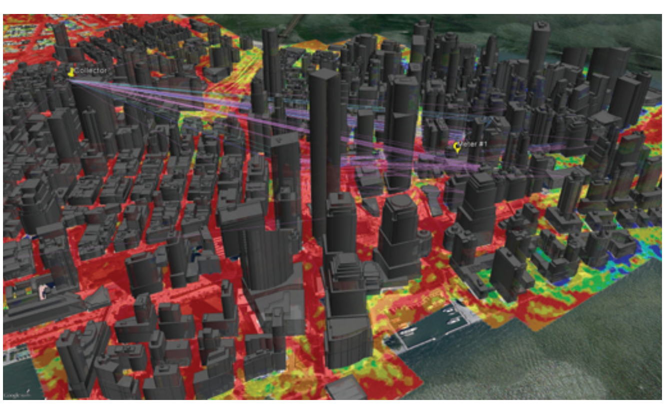
Base to hub links and traffic

When we attempt to solve latency issues in these networks, one of the immediate things that comes to mind is the proximity of consumers to data and processing centers. While it is true that the location of data centers in relation to the consumers can either increase or decrease latency, we must be careful that we don't arbitrarily start moving data centers based on geography alone.

Poorly located assets can lead to non-ideal data routing within the network, causing congestion and paradoxically increasing latency while attempting to alleviate it. But while reducing the distance data must travel is the most obvious factor in decreasing latency, it cannot be the only thing we consider.

We must also examine the scale of these systems, which cannot be determined from a strictly geographical proximity perspective. When we talk about an IoT network, we are talking about several systems for a large number of devices, all of which can be sending and receiving data, communicating under different protocols, in real-time, alongside already existing devices that are utilizing the internet. All of this data calls for a network that is intelligent enough to interpret said data and have the capability to route it properly. And all of this needs to happen instantly!

Such a network and its performance cannot be measured from a strictly hardware perspective based on technical specifications and pre-existing system parameters. An IoT network will need to be understood from a data analytics perspective. This includes real world data that provides traffic trends, averages, peak performances and traffic that may occur in emergency situations as well as analysis of the actual data that will flow through the network. Both of these types of datasets are instrumental for the successful planning and deploying of a network. Indeed, this data analytics approach may prove to be even more critical than the hardware perspective, since adding more devices to a system to accommodate more traffic can lead to further issues of scaling and traffic, not to mention an increase in cost. From a planning, performance and budget perspective, it will behoove engineers to ensure data is distributed within a network intelligently.



Ray tracing study

Fortunately the tools to support this approach are available – and this is where the proactive approach mentioned earlier comes into play. We can analyze system performance and properly plan a network even before deployment by taking into account various real world, as well as hypothetical factors. In doing so, scenarios that include any number of variables can be accounted for to ensure a properly dimensioned network. For example, one can use databases that allow for the creation of a 3D model for a given service area that includes geographical and physical characteristics such as land use consideration, terrain elevations and foliage. These databases and models can also include building information so that individual attributes of a given building, along with the other elements in our model, can provide a real-world visualization of a network's performance before deployment. These models and calculations allow for the inclusion of utility poles and other asset mounting locations in order to help engineers determine the best physical locations of their assets and devices. Furthermore, exact hardware and mobile device specifications can be used in these calculations in order to determine preferential equipment as well as potential coverage gaps in a network.

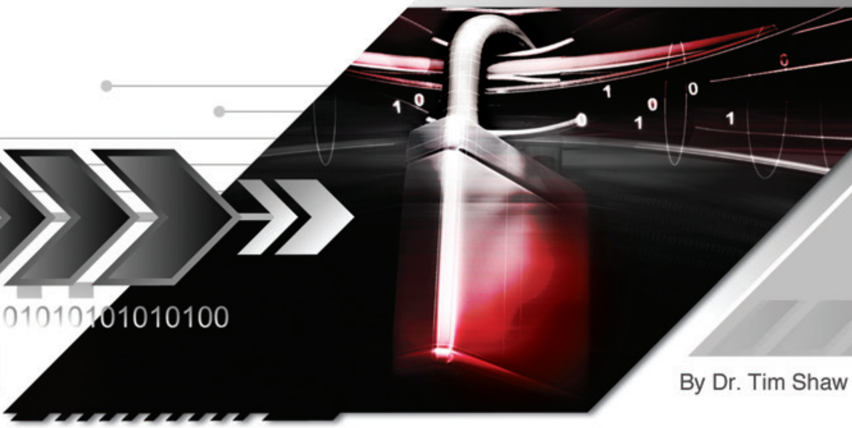
The real value of such calculations and where we are most likely to alleviate latency issues prior to deployment, comes from the real-world usage models that can be created. For example, once we have created a model of a network with the service area information, the assets to be mounted and the mobile devices to be deployed... we can then model traffic through the network to determine the overall health of the network. Based on this model we can then ensure that: a network is passing data optimally, the network is redundant and will accommodate future expansions, and finally, there are no critical or weak spots in the system by analyzing the traffic going through each node. Of course this information can be used to ensure latency is minimal while modeling average traffic, peak traffic or other scenarios. Specific databases can be used in these models such as social media data that shows traffic over a determined amount of time in a given area to show where there may be traffic and where it is most likely to flow at any given time. We can also take into account various service types and adjust our network accordingly to accommodate both latency and bandwidth requirements. For example, in a public safety application in which low latency is a requirement but bandwidth may not be used as much as other applications, a network can be dimensioned specifically to the service behavior. By modeling various scenarios based upon the data available to us, engineers ensure a network is robust and redundant before deployment. Latency, coverage gaps and critical points are eliminated or minimized and network buildouts fall within budget forecasts.


High resolution model of service area

We have grown accustomed to the instantaneous nature of the internet and our devices. Moving forward, we will have to develop and embrace new paradigms to ensure evolving networks such as IoT continue to meet the expectations of consumers, enterprise and mission critical applications. There is no doubt that as more of these networks are deployed there will be some growing pains. IoT networks may not be as efficient out of the gate as they will be 20 years from now and the overall health of these systems will, in no small part, be dependent on instrumentation that analyzes real-time performance once these systems are being utilized. However, a properly planned and dimensioned system before its deployment will help smooth the transition into an IoT world.

ABOUT THE AUTHOR

Bob Akins is the sales and marketing manager at EDX Wireless. He is responsible for identifying and developing new opportunities across the wireless industry and actively contributes to not only sales and marketing, but also support and product development. In this role, Akins has worked with utilities, smart grid vendors and consultants world-wide as they plan and deploy AMI, distribution automation and other mesh networks. Mr. Akins joined EDX in 2012.



By Dr. Tim Shaw

SECURITY SESSIONS

Sure It's 'Smart', but Is It Really, Truly All That Smart?

Industrial cyber security is challanging for a number of reasons, one being the range of "smart" devices that we commonly use for monitoring, analysis, protection and control. These "smart" devices contain microprocessors and stored programming so they kinda have some of the properties of a 'computer'. But you can't protect them in the same way you protect a Microsoft Windows 2008 server. But more to the point, because of their differences you may not even need to protect them all that much. Many of these smart devices are nearly invulnerable to cyber compromise and so attempting to protect them is a waste of time and money.

In the electric power industry, as in other industrial segments, there are pressures (including regulatory, political and economic) pushing you to ensure that your critical infrastructure facilities are protected against both physical attacks and cyber attacks. Putting up fences and gates and hiring guards costs money but you get a clear and obvious return on your investment every time you drive up to the gate and have to prove that you have the right to enter the facility. On the other hand investing in cyber security usually appears to be spending money to protect your plant from something that probably would not have ever happened anyway, and if it's working well nothing bad actually does happen.

But regardless of how you may personally feel about cyber security there is overwhelming evidence that we are under constant cyber attack by those that wish to steal our technology, gain a competitive advantage, learn our secrets or just rob us via cyber means. An appalling number of domestic industrial facilities have discovered that their systems and networks have been invaded and infested with malicious software, even if such infestations have not caused obvious harm or damage. Such discovery often accompanies their efforts to establish cyber security defenses; they find out that they have already been successfully attacked when they turn-on their shiny new detection mechanisms. So I don't intend to argue for the need to have adequate cyber security – that should be a given by now. But I do often see misguided efforts to place protections around digital I&C components and smart devices that may not require such protections; usually as a result of trying to apply IT cyber security methods to industrial automation.

One example of this is something I came across recently. At one facility the list of identified important digital assets included a large number of smart transmitters that supported HART protocol rev 5. These transmitters were being used in analog mode and providing a 4-20 mA signal to their respective controller. HART communications was only used (via a hand-held calibrator) for calibration/configuration purposes. The IT folks were very concerned about having malware spread from transmitter to transmitter via a cyber compromised hand-held calibrator. Stop laughing, I am being totally serious. It was pointed out to the IT folks that this was highly unlikely to be a viable attack vector because of several factors: first, the program code in the transmitters themselves was in ROM and not field alterable via cyber means. Only user-alterable settings stored in flash/RAM could be manipulated and improper settings would merely result in an invalid analog value being output. Besides, the calibration process included a settings check by a second tech for any instrument used in a critical or dangerous process. Second, the HART protocol has very specific message types with pre-defined formats and there were no commands that would allow for the access and modification of program code (and any improperly formatted message would be detected and rejected as 'bad'.) And third, the hand-held calibrators being used also had ROM based program code and could not be field reprogrammed or have their "firmware" field updated.

You would think that this would have settled the matter, but you would have been wrong. The IT folks had apparently been doing a lot of reading about the 'supply chain threat' and felt that it might be relevant in this case. For those who may not know this term it refers to actions taken by an adversary, for example, at the vendor/manufacturer's facility to introduce unauthorized software functionality into the valid program code for a device/system, or to substitute poor quality components. It can also apply to using the trust granted to a vendor's field service group to gain access to their systems at customer facilities for the purpose of malicious tampering. It can also encompass the possibility of using that same field service/support channel to provide malicious patches and software updates to customers. The IT folks were concerned that there could be hidden malicious functionality in the program code of the smart transmitters, introduced via the supply chain attack vector, such that at some point, based on some trigger condition, the transmitters would malfunction in a dangerous manner (e.g. swing the analog value up and down between the maximum and minimum calibrated values.) In response it was pointed out that smart transmitters, unlike PCs, do not have time-of-day clocks and in fact do not keep track of time in any manner. Thus a trigger condition could not be time/date based and a number of transmitters would have no way to synchronize their malfunctioning. It was also pointed out that the transmitters had no way of knowing what kind of plant or process in which they were being applied and that manufacturers make such devices in quantity and sell them through stocking distributors, so there is no association between a specific device and where it will eventually end up being used. The point being that an adversary who got into the manufacturer's software development group could not control where the modified products ended up being used and it is likely that wildly malfunctioning transmitters would be popping up all over the place and not necessarily at the targeted plant. Much the same situation would exist for the hand-held calibrators. The upshot was that those smart transmitters were determined not to require any special cyber security protections.

Of course there are other smart I&C devices that are far more complex than a smart transmitter, and some may need some level of cyber protection. A good example would be a low-end digital trend recorder that supports data dumps to removable media and asynchronous serial communications via an RS-232 link using MODBUS-RTU protocol to enable the fetching of their current input measurement values. Today many of these devices also have field-updatable firmware support via portable media, possibly via a USB port. Many such devices also support optional contact outputs that are activated by crossing user-defined alarm limits on designated inputs. Although such contacts could be used for device control, they are normally intended for triggering external alarm annunciation. To an IT person such a device seems to be ripe for cyber compromise via its numerous, 'obvious' attack vectors: it has a bi-directional communication channel, it has one or more interfaces (including USB) for the connection of portable media and it allows for the over-writing and replacement of its programming. And lastly, it could be tricked into ignoring alarm conditions or into creating false alarms.

Putting aside for the moment the value to the attacker of messing up a trend recorder, either to inaccurately display process measurements or to improperly process alarm conditions, the supply chain issue would be pretty much the same for this kind of device as was stated for the smart transmitter example presented previously. The major difference here is that field-alteration of the firmware is possible, as long as a malicious (or manipulated/unwitting) insider can get access to the device and insert specially prepared portable media. Sounds simple right? Actually many such devices store their entire operating program in Flash (non-volatile) memory and copy it to RAM when they are rebooted/turned-on. Firmware updates over-write the entire contents of Flash with an entire new operating program. This is done under user control via an integral menu system (not just because you inserted portable media.) Unlike with a PC where you can add a new program/task to the running operating system, in this case you must provide complete program code to perform ALL of the normal trend recorder functions and then also include the additional malicious functionality and trigger logic. Because many such devices use custom hardware designs and low-end CPUs (to keep manufacturing costs low) the optimal approach would be to reverse-engineer/disassemble the program code in the Flash memory and then alter it appropriately. This is no small feat of engineering and that brings us back to the question of the value to the attacker of expending such an effort. And we haven't touched on how that new code would get onto portable media that is then carried into the control room and used to update the recorder. Also note that all such changes could be reversed merely by reloading the prior version of non-altered firmware.

But what about the MODBUS communication link to the trend recorder, doesn't it need to be protected? If I can tap into that communication link can't I wreak some havoc, and without having to deal with inserting modified firmware into the device? The answer depends on what functionality is supported by the link. In this case the assumption is that the trend recorder provides a read-only ability to enable some other system to fetch its current input values (probably via a READ MULTIPLE REGISTERS command.) Injecting false message traffic on the communication channel can be done to 'spoof' either end of the channel: an attacker can send falsified responses incorporating bad data to a read register command so the 'other system' sees bad values. Or the attacker can send messages to the trend recorder.

Of course the trend recorder probably only supports two Modbus commands: read register and read multiple registers. Any other command (or those commands with bad parameters) or malicious message sequence will be rejected by the recorder. Of course the attacker would have to disconnect the recorder and connect (and leaves in place) a computer device that continues to respond to data requests with bad values, something that might be hard to do without someone noticing. And again that brings us back to the question of the value to the attacker of expending such an effort. Mind you, there can be MODBUS communications that offer a serious attack value, particularly if they provide for remote operation and control of plant equipment. But each case needs to be considered for the particular access and impact that could be provided to an attacker who can get onto the communication channel.

I could continue the discussion by working my way up through other smart devices such as protective relays, digital PID controllers, analyzers, smart control elements, etc. But I am hoping that the point has been made. Just because a device is "smart" does not necessarily mean that it is cyber attackable or that the consequences of putting the required effort into a cyber attack to compromise such a device are worth the "bang for the buck." Each case needs to be looked at in light of the technical and functional capabilities and design of the particular device (or class of device.) But by doing such assessments it should be possible to justify the correct level (if any) of cyber protection provided for your smart devices.

Cyber security for our essential/critical digital automation assets is important. But cyber security costs time, money and uses personnel resources and thus its application needs to be focused where it does the most good. Attempting to protect things that have little likelihood of being successfully compromised is wasteful and unproductive. It isn't actually all that hard to develop criteria that help you categorize your digital assets into groups that require no, some or even a lot of cyber security protections so that you can optimize your efforts. But that will have to be the subject matter for a future column.

ABOUT THE AUTHOR

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

Guest Editorial 1

IEC 61850: Much More Than a Protocol

By Bruce Muschlitz

Introduction – What is IEC 61850?

When asked the question "what is IEC 61850?" most people would respond "an automating protocol". Although this is part of the answer, a better answer would be "a comprehensive way to look at all aspects of an automation system". The experts who designed IEC 61850 wanted to optimize the automation system over the full life cycle of these systems, not just the operational period. This broad view resulted in best-practice answers to the questions:

- What is an automation system?
- How much environmental hardening of devices is needed?
- How do you design an optimal automation system? How can we validate this design?
- What performance parameters are needed to operate an automation system?
- How to assemble an automation system from piece parts?
- Which abstract services and models are needed by automation system?
- **How do we implement these models and services on real devices?**
- How do we validate the as-built automation system against the design goals?
- How do we do all this using a standards-based approach (not re-invent the wheel)?
- What are the best practices in the design of automation systems?

If you are an expert in IEC 61850, you will recognize that the above list follows (in order) the sections of IEC 61850 except for 61850-2 which is the glossary; whereas the 'automation protocol' portion is only the highlighted bullet above.

What is an automation system?

Before discussing IEC 61850, we need to define exactly what is an automation system. The normal vague answer "a collection of hardware and software used to monitor, control, and protect a process". This appears to be a reasonable definition, but it is not precise enough to lead to an optimal implementation. For the purposes of this paper, an automation system is "a system used to monitor, control, and protect a process which has been optimize over the lifetime of the process". There are 2 key points which have been added:

- Some optimization function has been applied to the design
- The lifetime of the controlled process is explicit

To clarify our thoughts, a simple automation system will be considered. Figure 1 shows a simple automation system. The system consists of a temperature sensor, smoke detector, and a furnace. The objective is to enable the furnace when the temperature is below the setpoint and disable the furnace when the smoke level is above the setpoint.

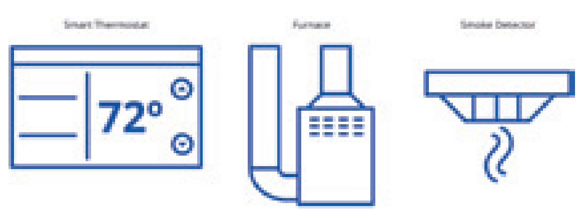


Figure 1 - Automation system before integration

One way to design this system is to purchase a thermostat, a smoke detector, and a furnace then 'integrate the system.' We purchase a wireless smart ZigBee thermostat, a wall-mounted smoke detector, and a furnace designed for a wired thermostat. All we do is integrate the automation system.

Our first problem is that the thermostat and furnace use incompatible protocols. We can fix that by purchasing a camera and also purchase a Raspberry Pi kit with one relay output; then just apply some custom software to convert the picture of the thermostat display into a contact output (very easy!).

Next problem is that the smoke detector protocol (audio output) is incompatible with everything else. We just need to buy another Raspberry Pi kit with a microphone input which converts the sound to a contact opening. Wire this in series with the other Raspberry Pi kit then wire to the furnace.

Now it is time to test the system. Because it is summertime and daylight, we assign a low temperature setpoint and we find that the furnace turns on, so we are done. Discard all the packaging (and instructions and wiring diagrams and source code) because the integration test was successful. Figure 2 shows the resulting system.

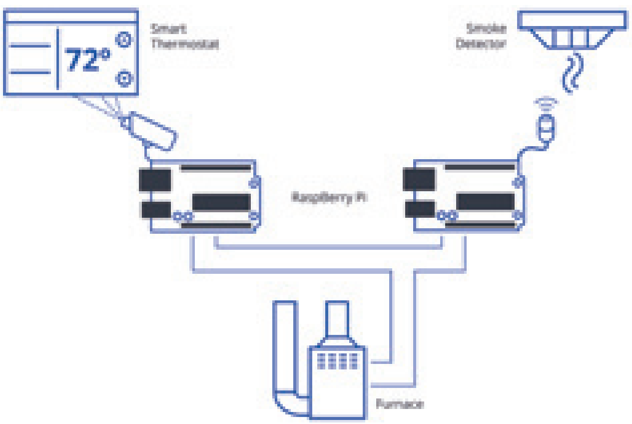


Figure 2 – Automation system after initial integration

Four months later, the house gets cold at night. We forgot that the thermostat display has no backlight. Simple enough to fix, just leave the lights on at all times (and pay for the extra power to run the light).

Two months later, the house gets cold even during the day. We forgot to buy a large enough furnace, need to buy another one. But now we cannot control both furnaces from a single contact closure. So we buy a Programmable Logic Controller with one input and two outputs. Program the controller and now we have a warm house.

A few years later, the thermostat malfunctions and the replacement has a different display style. No problem, just modify the Raspberry Pi code… where did we put that source code? Figure 3 illustrates the final system.

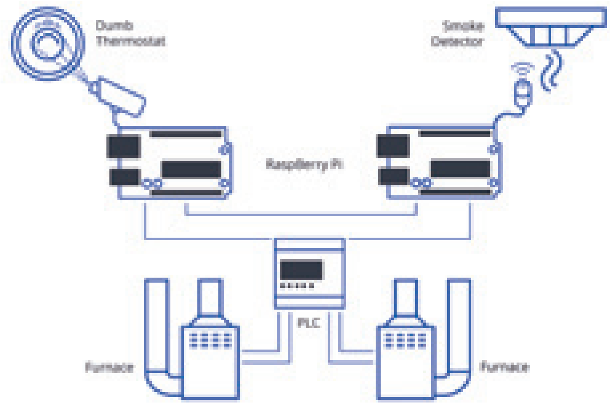


Figure 3 – Final Automation system after system upgrade

The above is a classical non-optimized design. Where did we go wrong? IEC 61850 can help us.

IEC 61850 Application Domains

IEC 61850 principles have been applied in many areas. There is no need to use all parts of the standard. In many cases, only parts of the standard have been applied with great success. For example, 61850-3, Quality Requirement and Environmental Conditions, has been applied to design and specify equipment for harsh environments such as electrical substations. In other cases, many parts of IEC 61850 are used to build automation systems for industrial plants. Sometimes, all parts of IEC 61850 are used to "future-proof" automation systems such as those in electrical transmission switching stations.

The data modeling principles of IEC 61850 have been applied for requirements analysis of automation systems (possibly implemented using protocols such as DNP3/IEEE 1815). The resulting automation systems have been used for industrial process control, co-generation, wind turbine plants, hydro-electric generators, and electrical substation systems.

Referenced Standards

IEC 61850 is built upon the premise that existing open standards should be used throughout 61850. Wherever possible, existing standards are referenced in an un-modified form, and this allows vendors and users to build products and systems which are fully compatible with other systems. For example, at the networking layer, IEC 61850 specifies IEEE 802 standard without modification or extension. A partial list of referenced standards includes:

- IEC 62351 – Security protocols
- IEC 81346 – Signal Naming
- RFC xxx – TCP/IP protocol suite and IP-based time sync (SNTP)
- ISO/IEC 8xxx and 9xxx –OSI protocol suite
- ISO 9506 – Manufacturing Messaging Services (MMS)
- ISO/IEC 8824-1 – Abstract Syntax Notation (ASN.1)
- ISO/IEC 8825-1 – ASN.1 encoding using Basic Encoding Rules (BER)
- IEEE 802 and ISO/IEC 8802 – Ethernet standards
- IEC 61869-9 – Instrument transformers
- IEC 62439-3 – Link redundancy protocols
- IEEE 1588 and IEC 61588 – Precision Time Protocol
- IEC 61000-4-x – Electromagnetic compatibility (surge, emissions, etc.)
- IEC 60870-2-x – Environmental conditions (temperature, seismic, altitude, vibration, etc.)
- IEEE C37.90.x – RF immunity
- Etc.

As can be seen from this list, IEC 61850 lets other standards define many of the 'protocols,' so suggesting that IEC 61850 is "just another protocol" is a wrong statement because most of the protocols are defined outside of IEC 61850.

Under-appreciated part of IEC 61850

The IEC 61850 standard should be required reading for everyone involved in power automation projects. It should be suggested reading for everyone involved in any kind of automation project The standard explains how to THINK about project development in general. It can be thought of as a step-by-step cookbook of items to consider before any purchasing decisions have been made.

IEC 61850-4 (System and Project Management Including Testing), reminds us that functional decomposition of a system is the first step in any design. This then drives requirements which is the basis of the automation project. Documentation is a key part of the design because automation systems often survive the memories of those responsible for the project. It is also important when the automation requirements change during the lifetime of the system.

IEC 61850-6 (System Configuration Language) defines a method to automate the system design and configuration of the devices that make up a system. The key concept is that a unified language is used throughout the process from functional specification, assignment of functions to devices, device configuration, intra-device signal flow, inter-device signal flow, primary equipment connectivity, and communication-level connectivity. This results in a single file containing most of the details of the as-built automation system. The power of this approach is that this same file (System Configuration Description) can be used to generate project reports such as an overall one-line graphic, graphics used on protective relay faceplates, and asset lists. Because the language is extensible, it can also be used to document information such as the geographic position of primary equipment ("the breaker is over there"), commissioning test results, and also be used to configure equipment simulators during maintenance.

IEC 61850-10 – Conformance Testing defines a method to determine whether the components of the automation system are compliant to the standard. For this purpose, a component is required to be accompanied by a mandatory set of documents which formally declare the capability. Using this formal definition, a test plan can be developed to test each of the declared capabilities either as static tests (is it in the instruction manual?) or dynamic tests (does it respond properly given a specific stimulus). Additionally, this section defines how to measure the performance parameters (how fast does it do …") specified in the formal documents. These formal documents can also be provided to potential customers to assist them in vendor selection without requiring reading thousands of pages of device documentation. This part is valuable to determine HOW formal documentation can be created for any type of device.

Applying IEC 61850 – Operational Phase

IEC 61850 concepts can be considered when designing any automation system. A few examples will illustrate IEC 61860 applications.

Time synchronization is important to every automation system. The requirements for the resolution and accuracy of the timestamp depends upon the specific application within the automation system. IEC 61850-5 provides guidance for the time synchronization requirements. In many cases, these requirements span orders of magnitudes; some parts needing highly accurate timestamps (such as raw samples of the AC analog values) and some low accuracy timestamps (such as times when breaker closures are made). For this reason, IEC 61850 defines a common SNTP synchronization mechanism and allows others such as PTP and IRIG-B to be layered on top for additional synchronization requirements. From a system perspective, there are many good reasons to perform the time synchronization over the same Ethernet LAN as other communication.

The concept of a process bus is central to 61850 applications. Process bus connects the "field I/O" to the automation equipment. This includes periodic samples (using Sampled Values from 61850-9-2) as well as aperiodic data (GOOSE from 61850-8-1). The UCAIug has defined an easy-to-use "Merging Unit" which emits 61850-9-2 sampled values with very few options.

Synchrophasors are used in advanced measurement applications. These are high-speed measurements of the magnitude and angle of the sinusoidal waveforms. IEC 61850 simply treats these as "normal" Sampled Values. Synchrophasor measurements have quickly become necessary components for analysis at both the local and wide-area levels.

IEC 61850 is now publishing standards to extend the periodic and aperiodic sampling from the LAN to the WAN to allow wide-area measurements. These will be specified in 61850-8-1 and 61850-9-2 as the "Routable GOOSE" and "Routable Sampled Values" which send the measurements over standard IP-based communication protocols.

IEC 61850 can be applied during the design phase to help decide which data is needed for various parts of the automation system. This then drives the selection of sensors needed to provide that data. IEC 61850-6 Configuration Language can ensure that every needed signal is produced somewhere in the automation system.

Applying IEC 61850 – Engineering Phase

IEC 61850 also finds use during the concept development and detailed engineering phases. IEC 61850-3 provides a single-source best-practice document for the creation of hardened devices. Users should consider that the additional cost to comply with these stringent standards will often pay back many times with increased reliability and lower long-term maintenance costs.

IEC 61850-6 allows documentation at the specification, as-designed, and as-built phases. This documentation can be converted into a wide variety of manager-friendly formats for both post-project analysis and studies of extensions to the automation system.

One example of this is the System Specification Description (SSD) file which describes WHAT the automation system is to accomplish without reference to any real automation equipment. This allows the file to be used as a vendor-independent procurement document.

Upon completion of the detailed engineering, it is useful to determine if the system requirements have actually been met. IEC 61850-4 and IEC 61850-10 can be used to make this determination.

Getting Started

One of the main problems with IEC 61850 is that it includes almost every aspect of automation design. It can be difficult to determine where to begin the journey of IEC 61850. The first place to begin is to fully understand WHAT to automation system is expected to accomplish. Although it seems obvious, this is not always the starting point for many projects. Once this is well understood, IEC 61850 can be read in small sections. The best way to accomplish this is to concentrate on the narrative and ignore the detailed tables and figures and charts. IEC 61850 is a very readable document but the details are not always important for a first-pass understanding. After reading the standard, several high-level articles on 61850 should be read to reinforce key concepts. You must then decide which types of communication need to be used in the automation system, not all must be used together.

One common failing of many IEC 61850 projects is to ignore the standard as a planning tool. Once the automation system goals have been established, these goals must be coded into a System Specification Tool (SST) as described in IEC 61850-6 for a high-level analysis of what signals will be needed. After this, a trial mapping onto real devices using the System Configuration Tool (SCT) described in IEC 61850-6 can be used. This will show gaps in the understanding of the automation system. Iterating with these tools until a workable automation design is accomplished should be done before any purchasing decisions are made. The formal specification descriptions can then be applied to the procurement stage after which the real devices can be integrated using the 61850-6 tools.

Note that none of this above description is dependent upon actually using the IEC 61850 protocols in the final system. A DNP3 system can be developed using the same IEC 61850 methodology.

Summary

This paper has introduced IEC 61850 as much more than a protocol with emphasis on the structured design of automation systems. The original example of a less-than-optimal design can now be visited again.

Where did we go wrong? Our first error was to emphasize the pieces of the automation system without understanding the underlying process. The actual goal was to keep our house warm and safe but we lost that goal by first making assumptions and purchasing equipment from those assumptions. If we took the time to analyze the entire system, we would have started with the communication requirements: the furnace need to know when it should be enabled. An analysis of the signals from the transducers would have clearly shown that there was no compatible source. Documentation of the system goals and the low-level documentation (source code for the microcontrollers) was not maintained according to 61850-4 and even the environmental requirements for the sensors was not taken into account. Lastly, the test plan for the completed system was inadequate for the needs of the user. Using a IEC 61850-based approach would have resulting in a simpler, less expensive system with easy upgrade paths; and saved a lot of time, effort, and money.

Conclusion

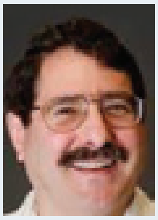
IEC 61850 is much more than a communication protocol, it is a “way of life” in the design and construction of automation systems. The MMS / BER protocol is actually one of the least important outcomes of the IEC 61850 standard. Many automation experts have devoted thousands of hours into the concepts of automation protocols; ignoring their collective wisdom is ill-advised.

IEC 61850 is influencing many existing protocols such as DNP3 with the concept of hierarchical data modeling. DNP3-XML configuration language was strongly influenced by concepts in IEC 61850-6. Systems have been designed using IEC 61850 but then implemented using other standards. Using IEC 61850 in the “legacy” environments allows a simplification of the system design and a much more robust set of documentation.

Lastly, the IEC 61850 protocols have been designed to co-exist with other protocols which means that mixed environments are easily possible. A simple example of this is DNP3 with GOOSE communications.

IEC 61850 presents an evolution of the design of automation systems from ad-hoc to very structured. These concepts can be re-used outside of the electrical substation environment.

ABOUT THE AUTHOR



Bruce Muschlitz is a Research Engineer at NovaTech with more than 20 years experience in project leadership and utility communications protocols. He is heavily involved with industry/national/international standards groups and chairs the UCAIug testing committee which is responsible for maintenance of the IEC 61850 device conformity testing program.

Bruce earned a MS in Electrical Engineering from Lehigh University. He is a senior member of IEEE, as well as, a member of the DNP3 Technical Committee, UCA International Users Group Technical, a member of IEC TC 57 on working groups 10 (IEC 61850) and 17 (Distributed Energy Resources), CIGRE, various IEEE PES committees, and is a founding member of the Smart Grid Interoperability Panel.

Guest Editorial 2

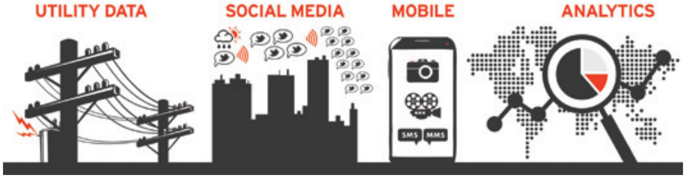
The Internet of Things Starts with The Grid of Things

By Ryan Zaczynski

"I want my toaster to talk to my Utility." – *Zac Canders, Co-Founder & CEO DataCapable*.

While Zac's statement drew more than a few chuckles among us here at DataCapable, he had a point: we've reached a time when technologies such as Toaster-to-Utility communications have moved from the realm of 'possible' to 'inevitable.'

The next technological revolution is already here, and it's collectively known as the 'Internet of Things,' 'IoT,' or '#IoT' – depending on whether you're respectively talking, bragging, or Tweeting about it. Regardless of the moniker, the Internet of Things is poised to change everything we know about the technology we interact with throughout our days. We give credit to Thomas Edison for building the foundation of today's grid – lots of wires and poles. We recognize 'Smart Grid' as bringing network connectivity to devices – all those intelligent devices like smart meters, smart reclosers, smart thermostats. We're now entering the era that power systems engineers have dreamt of for over a century, intelligently connecting all of these grid devices with each other.



Yet connectivity isn't just happening within the grid. This new era of change for utilities is also a new era of connectivity for customers - ask any call center and the rhetoric will be the same; customers are mobile, social and they want instant updates when the power goes off. It doesn't matter where you live or what language you speak. When a power outage occurs, customers want to be updated, on the platforms they prefer, and they want these updates fast.

Ten years ago, connections for a utility meant customers calling to report an event. In 2016, I spend a majority of my day working with utilities to show them how connections aren't what they use to be, how the electrical grid has been combined with the telecommunications grid and how two new layers have emerged - the customer, and interoperable grids. It's a connectivity journey that is changing how grid operators, engineers, and business leaders drive value from increasingly dynamic customers. It is the connectivity transformation that is building more meaningful relationships, new revenue streams for utilities and a truly connected grid.

Utilities are embracing the value of the customer. Together, the industry and those that support are just beginning to discover how a services-oriented utility can drive a deeper relationships and new efficiencies in the meter-to-cash business process.

Safety, reliability, and the customer are the core focus of any utility employee. In 2016, we must add interoperability. This changing customer dynamic, as we transition from the Baby Boomers to Generation X, and Millennials, speaks to a new mantra for every utility employee.

Interoperability of sensors, data, systems, telecommunications, protocol, utility teams, vendors, and the customer. It may seem like an insurmountable challenge, but without it, the true opportunity to save billions in energy efficiency, system integrations, and the end-to-end value from the generation station to the wall outlet will never be achieved.

The Internet of Things and its Connection to the Grid - How Do We Realize the Value?

Both myself and my colleagues see enormous potential in a complementary, utility-facing component to this new network – we call it the 'Grid of Things,' a solid foundation and innovative system of change that could affect all parts of the electrical grid (including, but not limited to, energy generation, transmission, and distribution). We believe we're witnessing the convergence of Moore's Law (that which computing power has doubled every year since its conception in 1965) and Metcalfe's law (the value of a telecommunications network is proportional to the square of the number of connected users of the system); this convergence is rapidly propelling us towards the Grid of Things.

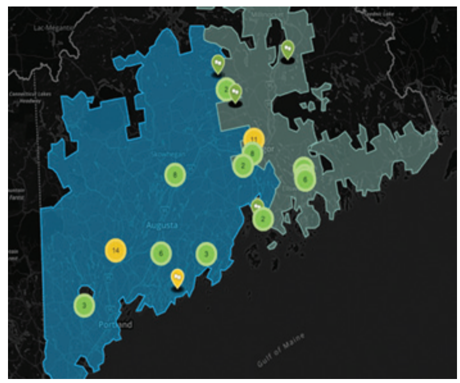
Our vision of the Grid of Things is an assembly of standardized web services & security protocols, robust software interfaces, open data formats, and supporting elements necessary for the seamless front-end and back-end connectivity of devices. The Grid of Things is the blueprint for true interoperability among devices, beginning with the power that brings them to life, and ending with Zac knowing his toast is going to be perfectly browned in the morning (because that's how he likes it on Saturdays). The role of interoperability is just beginning to emerge.

Recent examples of the Grid of Things

Getting a bit more specific, the Grid of Things is primarily comprised of interoperable hyper-local devices (like toasters) along with associated data & metadata (for example, Zac's personal preference for 'toastiness,' time of use; quantity; etc). The potential of front-end, consumer-facing interconnected technologies has already proven apparent with the introduction and adoption of devices such as the Nest thermostat and Roomba vacuum (and their associated consumer app interfaces).

At DistribuTECH 2016 two examples, EPRI's Outage Data Initiative (ODI) and Duke Energy's Coalition of the Willing both showcased how data from devices can be shared in real-time across utilities and vendors. Both required a simple set of rules, standards adoption and best practices software development.

The Outage Data Initiative: The first step towards interoperability between utilities and vendors began at the Application Layer with the Outage Data Initiative (ODI) working group. The Outage Data Initiative is a group of representatives from utilities and vendors that are interested in utilizing outage data from external sources. The group's goal is to share outage data in a common format so it can be easily consumed by any software platform without custom integration time and costs. The result of this work was the ODI standard and was showcased at DistribuTECH 2016. By formatting the outage data into the standard that came from a device (a Raspberry PI in this scenario), it was shown how easily and quickly it can be consumed by a third party. Sharing data between neighboring utilities can help understand the potential impact of a storm as it approaches and provides a clear understanding of the crew that should be ready to handle the impact. Sharing the data with police and fire systems can aid with the help of people in need. DataCapable is one of the many industry leaders that is supporting the vision and development of the standard. Together we have shown that the safety and reliability of grid operators and customers will realize enormous efficiency gains just by leveraging interoperability during major storm events.



In a recent example of interoperability, two neighboring United States utilities showcased how standardization and sharing of outage data can enable value; proactive staging of crews, improved predictions of outage impacts from inclement weather, sharing of resources during times of natural disasters and inclement weather all become a reality just by embracing interoperability.

The Coalition of the Willing: is a partnership of over twenty teams representing universities, vendors, research labs, utilities, and governmental agencies to support the development and commercialization of field interoperability of smart grid devices and associated systems. The framework is called the Open Field Message Bus (Open FMB™) and it was showcased at DistribuTECH 2016. It is recognized as another example of interoperability activities happening in the grid. The value is that one-day grid operators, engineers, and third party developers can choose from a myriad of hardware and software options, share data faster across all parties, and enable efficiencies from distributed intelligence and renewables integration.

Together We (The Industry) Can Connect

The Grid of Things is a new area of opportunity for electrical utilities to maximize their investments, explore new value propositions, and embrace try-before-you-buy scenarios – all while passing the value back to their customers via the intelligent devices they own. By embracing best practices in web service development in conjunction with protocols connecting the data of one smart grid device or platform to another, I'm confident that the Internet of Things will reside on the solid foundation of the Grid of Things.

If you have an interoperability story to tell. Or these examples of interoperability inspired you, let us know. The customer and interoperable grid journey have just begun. Collaboration and standards adoption will take buy-in from all stakeholders in the utility industry. Together we can lay the cornerstones for the foundation of the Internet of Things: it all starts with the Grid of Things.

ABOUT THE AUTHOR

Ryan Zaczynski is DataCapable's Data Science & Analytics Director. In this role, Mr. Zaczynski works with DataCapable's engineering team and one of the world's leading research universities on developing next generation analytics and machine learning algorithms for DataCapable's platforms. He has experience across a diverse cross-section of industries in the areas of management, business analytics, and customer experience & support. Most recently Mr. Zaczynski has been involved in the standardization of outage data, and this work resulted in an invitation to meet with likeminded leaders at the United States White House.

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