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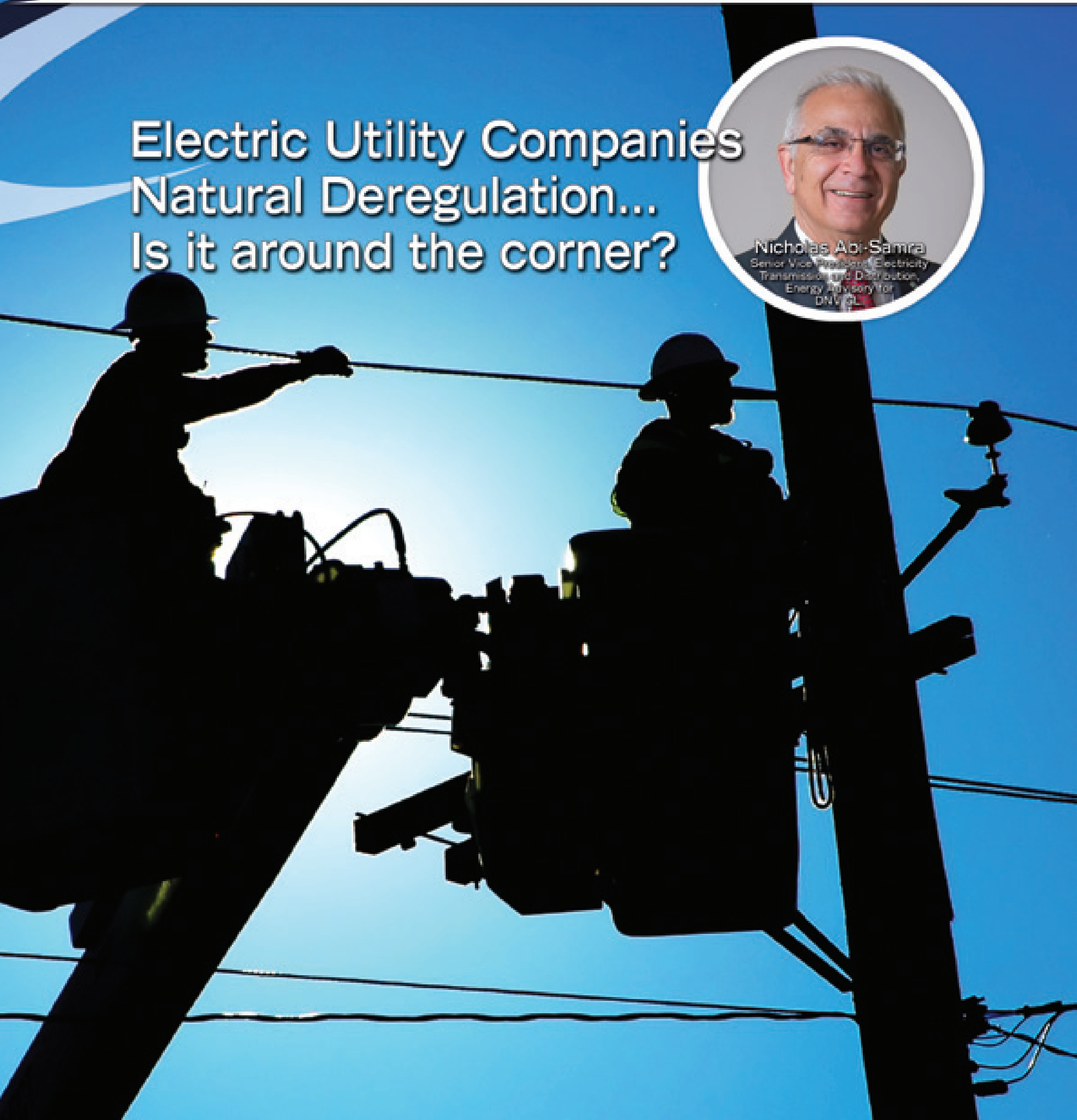

Electric Utility Companies Natural Deregulation... Is it around the corner?

Nicholas Abi-Samra
Senior Vice President, Electricity Transmission and Distribution, Energy Advisory for DNV GL

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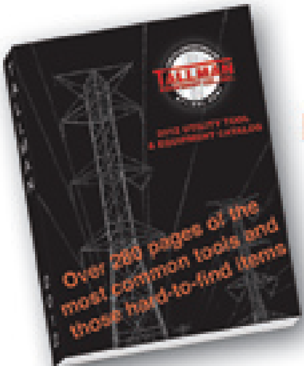

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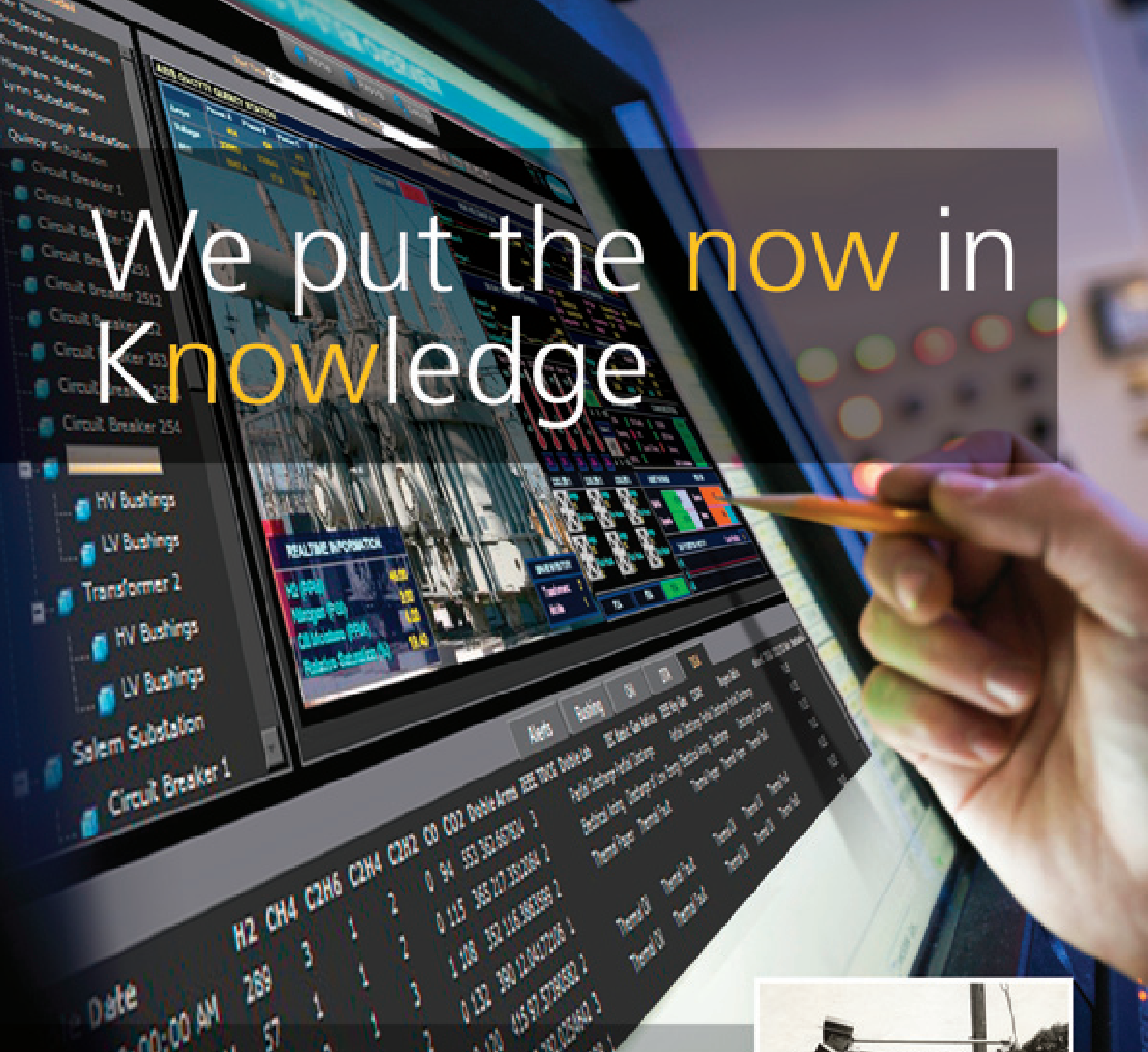
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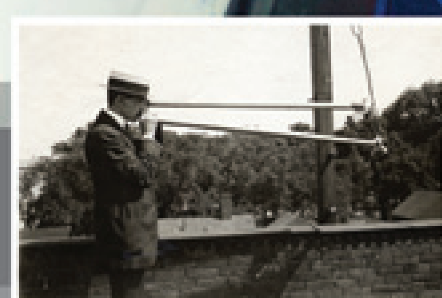

Editor-in-Chief

TERRY WILDMAN

POWERPOINTS

Exactly the same… only different

As we motor along through autumn, everything around us seems to be doing just what it always does. Trees are resplendent in their new colours; migrating critters are well under way; kids are in the early stages of their Christmas lists; the NIMBY crowd maintains their vigilance against offshore wind; winterizing projects are moving along; the Ontario government continues to upset the people; hockey season has started; vacations to sunny climes are on people's minds; and so on.

I happen to be one of the people the Ontario government is 'taking for a ride' because of the announced closure of the province's last coal-burning power plants by the end of this year. Don't get me wrong, I applaud the removal of coal from our system and the muck it leaves behind. What really burns me is the fact that the powers-that-be have turned the entire episode into a soap opera-esque fiasco with little regard for the truth about costs to the taxpayers.

Originally, the closures formed part of the platform on which the Liberal Party came into power in 2003. The deal for Ontarians was to replace the plants with better alternatives. "We'll replace our dirty, outdated coal-fired electricity plants – the biggest source of air pollution in Canada – with cleaner burning natural gas, and renewable energy such as wind and solar," stated Dalton McGuinty during his campaign to become Premier.

Once in power, he discovered his promised 2007 deadline was a pipedream. As time went by, people continued to gasp as the demand for energy grew and Ontario struggled to keep the lights on. The closure/refurbish deadline was then pushed to 2009 and finally to 2014. Missed deadlines notwithstanding, the government still passed the Green Energy Act to take the province in a new direction of finding and using clean, renewable energy sources.

All of this gave rise to the Ontario power plant scandal, the characterization given by members of Ontario's opposition parties to separate decision by the governing Liberals to cancel an 800-megawatt gas-fired power plant near Toronto prior to the Ontario general election of October 6, 2011. The review and cancellation of the gas plant came eight months after the government gave the boot to a similar project.

In 2009 the Ontario Power Authority (OPA) made plans for a gas-fired power plant just outside of Toronto citing again a rising demand for power in the area as well as the removal of 1,150 megawatts of supply from the grid due to the closing of one coal plant in 2005. The OPA mandated that the new power plant meet or exceed emissions standards that were 70 percent stricter than what the Ontario Ministry of the Environment required. On the plus side, a Public Health centre and Ontario's Chief Medical Officer of Health concluded there was no evidence that the addition of a natural gas-fired generation facility in the region would have a negative impact on the health of southwest Greater Toronto Area (GTA) residents.[1]

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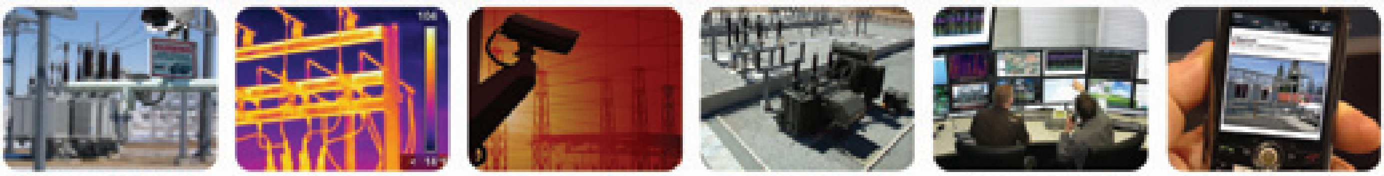

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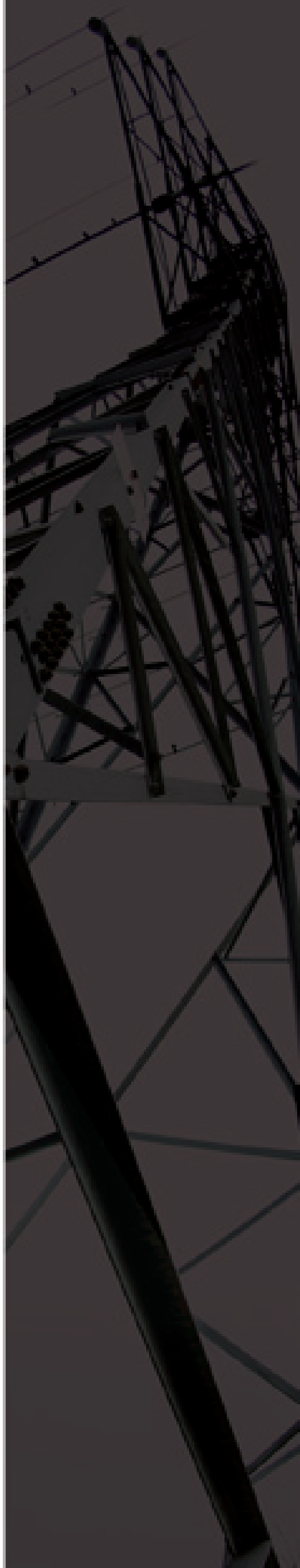

But opposition to the plant continued to grow. Local opponents rallied at the Ontario legislature and brought in American environmentalist Erin Brockovich to help generate publicity for their fight to keep the new building out of their neighbourhood. In October 2010, giving in to increasing opposition, Liberal energy minister Brad Duguid announced the cancellation of the new gas plant proposing instead to offset increased power demand through improvements to transmission lines.

In June 2011 the Liberal government decided to review the building of a promised second gas plant. One opposition critic charged that, "This has got nothing to do with the environment this is Liberal cabinet ministers and former Liberal cabinet ministers who are worried about losing their seats." The Environment Minister at that time, John Wilkinson, fired back saying the review has, "Nothing to do with politics. It has to do with ensuring that my ministry does what it's supposed to do, which is to protect human health."[2]

On September 28, 2011, the Ontario Liberals announced that if re-elected, they would relocate the now controversial natural gas-fired power generating station already under construction. This motion would again bring into question the role politics should play in controlling electricity policy to say nothing for the escalation of costs associated with moving the entire project.

It appeared I wasn't the only one in the province who was pissed off. On October 6, 2011, the Ontario General Election returned only a minority Liberal government – a win to be sure but by only the slimmest margin – a far cry from the landslide victory they enjoyed a few years earlier.

The following summer, opposition members of the Legislative expense committee asked the new Energy minister Chris Bentley to produce all documents related to the gas plant cancellations. The Minister complied and on September 24, 2012, Bentley handed over thousands of documents. The problem was that some 2,000 pages had been redacted. As a result, Bentley faced 'extraordinary punishment' – possibly jail time – after opposition MPPs used their majority in the legislature to ram through a motion to probe the power plant cancellation.

On October 15, 2012, Dalton McGuinty announced his resignation as Liberal Party leader and Premier of Ontario as soon as the party could hold a leadership convention. The new party leader and Premier is now Kathleen Wynne who is trying her best to distance herself from her predecessor and insists her office will follow the rules. She is ensuring the public that this kind of abuse will not happen again. But by association as an MPP under Mr. McGuinty, Ms. Wynne will have to wear part of this mess for some time to come whether she runs a 'clean' office or not.

Further digging into this can of worms revealed that top Liberal staffers – even in former McGuinty's office – illegally deleted emails tied to the power plant closures before the 2011 election. The emails were the only trail linking the chief of staff to the Minister of Energy and when questioned about his reasoning, the chief of staff simply stated that he likes "to keep a clean box... I don't know how to archive anything." The reaction from Ontario's Privacy Commissioner was unequivocal, "It's clear they didn't want anything left behind in terms of a record on these issues." Despite breaking the Archives and Recordkeeping Act and scoffing at freedom-of-information legislation, the perpetrators will not face any disciplinary actions because there are none. The McGuinty Liberals failed to pass adequate legislation that would have given the power to penalize such activities.

In the spring of this year, the government was mantling a $900 million cost to scrap the power plants yet told the public that only $230 million would have to be found. At the time of this writing the taxpayers of Ontario – me included – are looking at nearly $1.3 billion in 'scrapping' charges. I still cringe when I see the 'Debt Retirement Charge' on my Hydro bill knowing the payment is for overrun costs to build a Nuclear Power Plant east of Toronto during the seventies and eighties. I likely won't live long enough to see this bill paid off. At least those added costs were primarily due to inflation and increased borrowing, costs that would have been tough to predict and therefore mitigate. Current problems are a totally man made breach of trust that could have, should have never happened let alone be played out in our Parliament.

I guess it really is true – the more things change, the more they stay the same.

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1 Ontario Power Generation – Southwest GTA Replacement Power Plant Backgrounder

2 Global News – A timeline of the cancelled Mississauga and Oakville power plants


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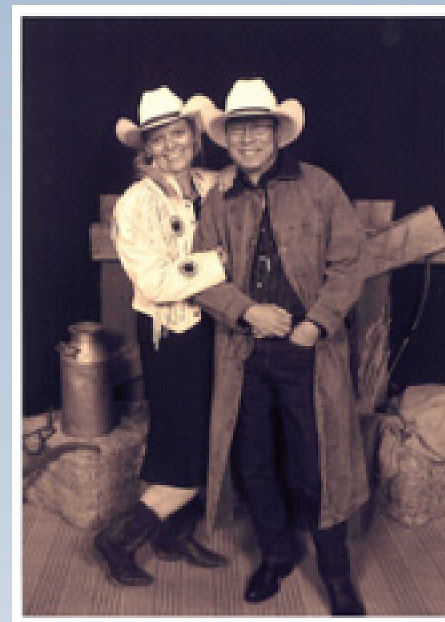
8th Annual CIGRÉ Canada Conference

Over 320 registrants attended the 8th annual CIGRE Canada Conference hosted by AltaLink Management Ltd in Calgary, Canada. The theme of the conference was "Modernizing the Grid to Better Serve Evolving Customer Needs". The conference included CIGRÉ Study Committee workshops, student posters, panel sessions, and technical paper presentations.



Four workshops were conducted prior to the start of the conference. SC B5 Protection and Automation presented the morning workshops, "Lifecycle Management for Protection and Control Systems", and "Industry Updates on Protection, Control and Automation". In the afternoon SC A3 High Voltage Equipment presented "High Voltage Equipment Root Cause Failure Analysis (RCFA), New Applications and Developments" followed by the SC B4 HVDC & Power Electronics workshop on "Developments and Applications of High Voltage Direct Current (HVDC) Grid.

The conference was opened by Mike Bartel, Conference Chair, and Mohamed Rashwan, CIGRÉ Canada Chairman. The conference theme was introduced during the keynote speech, presented by Dennis Frehlich, Interim President and CEO of AltaLink Management Ltd., asking the question where are the power and transmission industries heading in the future, and what role do customers have in defining that future.

Three CIGRÉ panel sessions discussed "Customer values and impact", "HVDC in Alberta" and "Innovation for The Electric Industry – What we are doing to serve evolving customer needs". Fifty four technical papers in parallel sessions focused on CIGRÉ Study Committees A3, B4, B5, C2, C6, D1, and D2.

Thirteen student submissions from 10 universities, representing Brazil, Canada, Colombia, Egypt and Iran were displayed during the Student Poster Sessions. The winning entry was "Accurate Fault Location Estimation in Transmission Lines Under High DC-offset and Sub-Harmonic Conditions".

During the breaks and evening receptions the attendees were able to discuss the modernization of the grid to server evolving customer needs with over 35 exhibitors.

INDUSTRY NEWS INDUSTRY NEWS

Canadian Electricity Sector Celebrates Record Lows in Occupational Injuries and Illnesses

Ottawa, ON, November, 2013 - The Canadian Electricity Association (CEA) recognized numerous Canadian electricity utilities and their front-line employees at the 2013 Occupational Health and Safety (OHS) Awards in Ottawa. Each year, CEA tracks the safety record of its corporate utility members. The annual OHS Awards recognize the top performers.

In addition to the corporate awards, CEA Lifesaving Awards were presented to utility member employees whose actions helped save the life of a fellow co-worker or member of the general public. The Honourable Dr. Kellie Leitch, Minister of Labour and Minister of Status of Women, was the evening's keynote speaker and distributed the Awards to winners.

"I commend the winners of this year's Occupational Health and Safety Awards for making Canada a safer place to work and live," said the Honourable Dr. Kellie Leitch. "The Government of Canada is committed to a safe, healthy and productive workforce. Occupational injuries and illnesses, and related employee lost-time injuries, are at a record low across the country."

Utilities recognized for safety excellence included Columbia Power Corporation, ENMAX Corporation, TransCanada, Yukon Energy Corporation, Ontario Power Generation Inc., Nova Scotia Power Inc., and Saskatoon Light & Power.

"I am pleased to see CEA members' excellent track record and their long-standing commitment to the health and safety of their employees, contractors, and to members of the public in the communities in which they operate," said Jim Burpee, President and Chief Executive Officer of the Canadian Electricity Association. "It is crucial that the electricity industry continue to deliver power in a safe, reliable, and cost-effective manner. The future is bright for Canadian electricity."

While the Canadian electricity industry is faced with infrastructure renewal and skilled workforce shortages, employee safety remains a paramount priority. CEA's Occupational Health & Safety program provides a member-driven forum for health and safety professionals to develop strategic partnerships and forward-thinking initiatives focused on improving the overall safety performance of the electric utility industry.

AEP Honored As Top 100 Military-friendly Employer

Columbus, OH, November, 2013 - American Electric Power (NYSE: AEP) has been recognized as one of the nation's top 100 "military-friendly" employers by G.I. Jobs Magazine.

This year's honorees were selected from among more than 5,000 employers with annual revenues of at least $500 million. The December 2013 edition of G.I. Jobs, which features the list of military-friendly employers, can be accessed at *http://www.gijobs.com/*.

"AEP is dedicated to recruiting, hiring and supporting military veterans, who have the technical skills we need as well as the personal characteristics we value, such as leadership, teamwork and decision making," said Nicholas K. Akins, AEP president and chief executive officer. "We are honored to be named a top 100 military-friendly employer."

The honored companies were selected based on their assets dedicated to military hiring, the strength of their recruiting programs, and their policies regarding National Guard and reserve service, among other criteria.

Approximately 1,770 of AEP's roughly 18,100 employees have served in the military. AEP's military leave policy provides pay differential and benefits for up to two years for reservists and National Guard members who are called to active duty in emergency situations. When employees are off work for required annual military training, AEP will make up the difference between military pay and their AEP base wage – up to 10 days each calendar year. In addition, the company's family military leave policy allows employees to take up to 10 days of leave to spend time with a family member who has been called to or returned from active duty.

G.I. Jobs helps provide training and career opportunities for veterans and those in transition from military to civilian employment.

Landis+Gyr Completes Agreement with CPS Energy for 700,000 Advanced Meters

Atlanta, GA, November, 2013 - Landis+Gyr announced an agreement with CPS Energy to supply advanced residential electric meters for the utility's grid modernization effort, a partnership that also supports the utility's New Energy Economy initiative to boost San Antonio's clean technology sector.

Landis+Gyr will provide 700,000 E-350 FOCUS® advanced meters with shipments beginning early in 2014. The meter upgrade project is anticipated to take four years. As part of the agreement, Landis+Gyr will partner with CPS Energy by supporting economic development including job creation and support for an innovation center in San Antonio and local education scholarships.

"As a partner on a number of initiatives, including a large scale demand response project, Landis+Gyr is helping CPS Energy create a more reliable grid and decrease load at times of peak demand," said CPS Energy President and CEO Doyle Beneby. "By bringing jobs and supporting education, Landis+Gyr is also growing economic development in and around San Antonio."

In addition to metering technology, Landis+Gyr is operating a direct load control program at CPS Energy. The utility is using Virtual Peak Plant™ software and load control devices from Landis+Gyr to verify and measure energy savings from conservation events. The program has the potential to provide a verifiable reduction of 250 megawatts of peak demand.

"CPS Energy is taking a leading role in promoting energy management and efficiency, and Landis+Gyr is pleased to have an active part in supporting these initiatives," said Richard Mora, CEO of Landis+Gyr North America. "The benefits derived from advanced metering, grid automation and advanced load management are proven to pay off in reliability, operational efficiency and energy savings."

THE GRID TRANSFORMATION FORUM

Envisioning the 21st Century Grid

Electric Utility Companies Natural Deregulation… Is it around the corner?

We are in conversation with Nicholas Abi-Samra, Senior Vice President, Electricity Transmission and Distribution, Energy Advisory for DNV GL.

EET&D: What do you see changing in the electric utility model?

Abi-Samra: For decades, the electric utility business model in the U.S., with its trillion dollar assets, has been organized on the principles of centrally controlled generation and variable consumption. It has delivered just what is needed in electricity, not less (for fear of reliability dings from regulators) and definitely not more (as there was nowhere to store it). Generation was mostly delivered from coal or nuclear plants, with its product still treated mostly like a public service rather than a consumer product.

Well, today, this model is coming increasingly under pressure from the convergence of flattening electricity demand, growth of green energy, cheap natural gas, distributed energy resources (DER) technologies, and microgrids. Microgrids came to the spotlight last year after Superstorm Sandy as key components for grid resiliency. This attractive trait came on the heels of an accelerating interest in customer-owned distributed generation for active participation in markets or enhanced reliability and dropping prices of alternative energy resources.

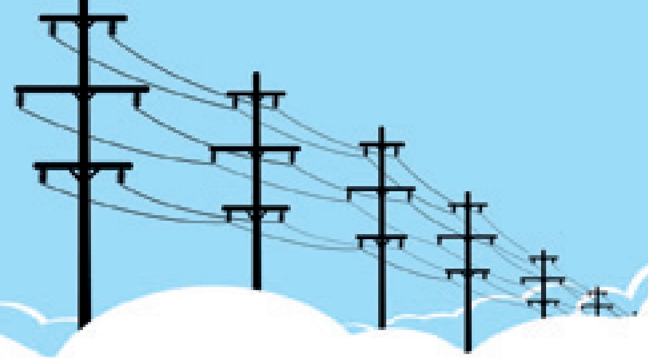
Pressures on the grid come from within, and result from rapidly growing requirements for infrastructure investment due to the aged infrastructure, general upkeep and, reliability upgrades, all of which are creating the need for unprecedented capital investment. Add to that the demands for hardening of the system, which came to the center stage after widespread long outages following 2011's winter storms, the 2012's Derecho in the metropolitan Washington DC area, and of course Superstorm Sandy. All these investments raise the price of delivery for power, which stretches the ability to recover necessary rates to support costs and shareholder returns. We just witnessed in July 2013 a credit rating downgrade of a major utility, due the large amounts of planned spending to address reliability challenges. A decrease in the credit rating would make capital more expensive for utilities to build and maintain the system, lower shareholder return, and result in higher electricity rates.

If these trends were to continue, albeit even gradually, we will be looking at the makings of a paradigm shift of the aforementioned utility business model. This could spell the era of "natural deregulation" of the present electric utility model, and the morphing into a new model based on more DER, microgrids, or virtual power plants (VPPs).

EET&D: We are hearing about an emergence of a decentralized model for the grid, what are advantages of such a model?

Abi-Samra: Well, a decentralized model, though not necessarily the panacea at least in the near future, can offer more sustainability, that is higher throughput efficiency. The centralized grid model of generation and power distribution model could have efficiencies as low as 35 to 40 percent, due to the inherent losses in the thermal cycles of conventional fossil fuel generation, and the losses in the transmission and distribution systems. On the other hand, microgrids consisting of efficient generation close the load, combine heat and power (CHP) technologies, and could be 85 percent efficient. That would also translate into a reduction of greenhouse gases (GHGs).

On the reliability front, today's centralized grid has long been susceptible to cascading effects from sometimes relatively minor events. Microgrids can act as "firewalls" offering enhanced reliability. The extra security and independence from potential grid interruptions are important especially for critical applications, such as hospitals and military bases.



EET&D: How will the smart grid facilitate this?

Abi-Samra: The convergence of smart technologies (i.e., automation, intelligence, sustainability, demand response, and storage) occurs only in one small-scale application: the microgrid. A microgrid integrates DER, storage devices, end-use loads into a single, "mini" grid which can operate in parallel with the traditional grid or in isolation from it. These technologies are currently struggling to withstand both technological and economic pressures in the larger grid.

EET&D: What impediments do you see standing in the way of making this a reality today?

Abi-Samra: On the perceived challenges, microgrids lack the economies of scale inherent in a centralized approach. Utilities can be reluctant to endorse microgrids, except in special cases, as they erode revenue generation. They also site valid safety concerns associated with microgrids with respect to utility workers, unintentional islanding, and protection issues. Another point of concern is the lack of established comprehensive standards for microgrids.

EET&D: What does the future hold for microgrids?

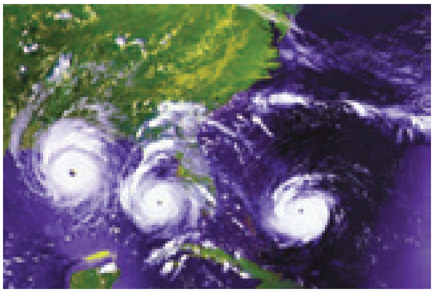
Abi-Samra: Microgrid deployments are expected to increase significantly over the next five years – especially in mission-critical operations, such as in hospitals and military bases. It is also expected that the present deployments and pilots, as well as the demand in rapidly developing countries and rural communities, will increasingly push the larger-scale adoption of microgrids. This is further reinforced by the fact that the developing world will not be able to sustain its economic growth if it tries to build solely on centralized electrical systems.

Because microgrids can serve non-utility sponsors, it would appear to challenge the traditional utility interest. However, microgrids can serve both the utility and the sponsor. Utility-controlled microgrids can take advantage of the islanding features of the microgrids, which will reduce load on a stressed grid and/or defer capital investment in capacity or to meet load growth. Thus, microgrid benefits can include meeting peak load constraints and load shifting. The ability of the microgrid to defer capital investment in infrastructure acts as an alternative to more capital-intensive infrastructure projects to handle load growth, optimize the supply-load mix on specific parts of the overall grid, or provide some ancillary services (such as frequency regulation) that can be monetized.

Microgrids can also allow the utility to optimize its available resources, while maximizing the use of renewable energy, limiting GHG, and still meeting load requirements. This approach is being explored in California. It is meeting the renewables targets and the aggressive mandates to limit GHG, which are driving the European Union (EU) to see the most near-term growth in microgrids. However, this could be at risk if the EU backs off its environmental mandates for economic reasons. In New York, in contrast, the non-utility potential microgrid sponsors are looking at microgrids to boost system resiliency in the wake of storms, such as Superstorm Sandy. However, with no in-place policy drivers, the challenge for utilities is to develop a positive business case for microgrids remains real, but is not always insurmountable, especially when some factors such as those detailed earlier in this article are met.

On the other hand, the present low cost of gas has a positive effect on a number of business cases for microgrids, which have a large percentage of conventional sources, rather than renewables sources. That may also propel some other aspects of the microgrid, such as combined heat and power (CHP) natural-gas-fueled projects. Policy drivers, if they become a reality in the USA, may be fragmented given that there are over 50 state-level public utility commissions to navigate and from which to gain approvals. Developers of microgrids face some different regulations based on the state they are in as the concept and definition of a microgrid does not exist nor is recognized in many states, and thus the microgrid may fall under some regulations intended for other concepts. It may, in some cases, be classified as a public distribution, and in other places may fall under the regulations developed to regulate steam heating utilities if it has thermal storage. If it has components that cross public roads, then it may fall under regulations and transmission and distribution (T&D) cost allocations or may be required to obtain a municipality franchise or be obligated to serve as provider of last resort.

The coordination of several microgrids and the operation of virtual power plants may ultimately mimic the full functionalities of central power plants. This would allow DER to take the responsibility for the delivery of energy services in conjunction with, and perhaps taking over the role of, utility central generation.



As the drop in price from distributed rooftop solar falls below the price of delivered power from some of the grid (the actual cost without subsidies has reached parity with the delivered price of electricity without subsidies), so does the demand from the grid. This could require a higher cost per kWh of power delivered, which in turn makes distributed options more competitive. This can be expected to be a reality in the next ten years, or even sooner in some places in the United States (U.S.) Their use can be further propelled by the development of cost-effective, scalable, technological breakthroughs in battery energy storage technology.

A perfect storm for the regulated utilities may brew if the assumption of relatively low cost of borrowing begins to get questioned based on the need for significant investments in dealing with aging assets and/or hardening the system against extreme weather at the same time that technologies erode power demand. Shares of utility companies have been a mainstay of conservative portfolios everywhere for generations. For risk-averse investors, utility stocks have offered reliable income, price stability, and minimal risk – a foundation that may be in peril.

In conclusion, it can be assumed that the future U.S. power grid may look quite different than we know it today – and utilities and regulators alike should get ready for it now. It is not hard to envision a grid that can ultimately be split into a controlled set of independently survivable islands, and then stitched back together as needed to create a balanced network of supply and demand. Sailing into these unchartered waters means that it is time to re-examine the strategic vision and innovation by electric utilities as their existence may be in the balance.

EET&D: We can't thank you enough Nicholas for finding the time to speak with us about the future of the grid and what we may expect going forward. It's highly topical and your in-depth explanation is very enlightening particularly on the emergence of a decentralized model and the future of microgrids.

About the author

Nicholas Abi-Samra, DNV GL, Senior Vice President, Electricity Transmission and Distribution, Energy Advisory, is experienced in power systems, planning, operations, maintenance and smart grid. Abi-Samra served as the General Chair and Technical Program Coordinator for the IEEE General Meeting of 2012. He is a professional engineer.

GREEN OVATIONS

Innovations in Green Technologies

Electric Vehicles Could Offer More Gain than Drain

By Dr. Mladen Kezunovic

Plug-in hybrid vehicles and battery electric vehicles pose a number of challenges for aging power infrastructures, including the potential to accelerate the aging of power transformers. But they also have the potential to play a role in smart grids as distributed energy sources to support demand side management and outage management programs.

Electric vehicles are gaining popularity with consumers as manufacturers invest in research and development to create more affordable plug-in hybrid vehicles (PHEVs) and battery electric vehicles (BEVs) that have greater energy storage capability and low-cost smart charging.

There are multiple studies using either statistical or predictive models to forecast the penetration of EVs; one estimates that by 2030 their market share could reach as much as 25 percent, while another predicts 20 percent by 2040. Most projections show that a significant amount of EV penetration is expected to occur within the next 30 years.

But as automakers respond to the demand for EVs and begin to realize a viable business opportunity, it creates challenges for utilities, property owners and all levels of governments. For utilities and power grids in particular, EVs mean more pressure on a system that's already heavily burdened.

At first glance, EVs may appear to be just another drain on the grid, but with the advent of smart grids, the adoption of advanced information technology and demand side management (DSM) programs, electric vehicles don't have to be another drain on power grids but instead could play a broader role more efficient DSM and outage management.

New Demands on Old Systems

EVs create challenges for any power grid; in the same way that deregulation and distributed energy resources (DERs) connected to the power grid create more stress by adding complexity and foster security and reliability concerns, EVs are yet another variable with which utilities must contend. To a large degree, smart grid deployment and adoption of advanced information technology are addressing these concerns, while utilities are looking to DSM programs to help them meet the flexibility requirements of smart grids.

EVs are one of the key drivers facilitating deployment of smart grids. If EVs continue to grow in popularity and are able to grab even a small piece of the automobile market, there will be a substantial impact to the power grid. In the unlikely event that all of the 250 million passenger vehicles in the U.S. were electric, each drawing approximately 4 kW and charged simultaneously, the load would be equivalent to the combined U.S. generation capacity of roughly 1,000 GW.

Transformers Must Change

EV charging will have an impact on power distribution, particularly on transformers, which will bear extra loads, as my Texas A&M University graduate student Qin Yan and I discovered through our research based on East Texas load consumption data. Power transformers are one of the most expensive pieces in any power distribution network. As EVs proliferate, a new load peak may be created that exceeds the transformer capacity. For example, a residential house with an EV may mean a need for replacement of a local transformer earlier than originally projected. That reduction in transformer life expectancy will in turn increase costs to utilities and consumers.

Our research used actual 15-minute load profiles from the College Station area of East Texas and explored various charging scenarios that included different charging start times, penetration rates and usage ratios. We concluded that higher penetration rate of EVs significantly increase transformers' loss-of-life factor. However, charging during the night will help to dramatically decrease the loss-of-life factor for all of the scenarios we looked at. In fact, distributed charging could almost eliminate the impact, although the changing seasons would also influence the impact on transformers, and utilities would have to coordinate with customers and charging stations to establish an optimal charging schedule based on actual load profiles.

Charging Must Get Smarter

How the charging of EVs is controlled will play a large role in dictating the impact these vehicles will have on the grid. One worst case scenario is that every driver plugs in their car when they get home from work in the early evening, drawing maximum current charge when the electric load is likely to already be at its maximum and distribution transformers are the most stressed. The effect would not be dissimilar to everyone turning up their air conditioning at the same time during a heat wave.

The key to managing the impact of the EVs on the grid will be intelligent charging, using a time management approach where the smart grid uses information about customer preferences and expected grid conditions to determine the best charging schedule. For example, a car might be charged in the middle of the night when electricity prices and demand on the grid are lowest. Various combinations of best charging times are still a topic of research.

Beyond addressing how these vehicles could be charged in a manner that would mitigate their impact on the grid, there is also a role for EVs to play in DSM and even give back by providing power in a vehicle-to-grid (V2G) scenario, where the vehicle batteries become an integral part of the grid.

EVs Can Give Back

For an electric utility, DSM is defined as 'the planning, implementation and monitoring of distribution network utility activities designed to influence customer use of electricity in ways that will produce desired changes in the load shape.' More simply, the objective of DSM is to improve the reliability of the power supply and create revenue. This might include peak clipping, valley filling, load shifting, strategic conservation, strategic load growth, and flexible load shape.

DSM generally includes two components: energy efficiency, which is designed to reduce electricity consumption during all hours of the year, and demand response, which is aimed at changing onsite demand for energy in intervals and associated timing of electric grid demand by transmitting changes in prices, load control signals or other incentives to end users to reflect existing production and delivery costs. The utility and customer cooperatively participating in DSM will provide the benefits to the customer, utility, and society as a whole.

EVs Could Dispense Energy

Electrical vehicles can be more than just a draw on the grid: they also have the potential to be a DER within a smart distribution system. When an EV is either in V2G mode or vehicle-to-building mode (V2B), it can actually supply power to the grid. Energy stored in an EV could support the local load in the power grid during high system loading and outages, helping to meet power demands and improving reliability.

When connected to the grid using a plug, EVs use electricity from an electric power grid to charge their battery – this is G2V mode. But it can also discharge electricity to a building while it is parked or during an outage – V2G or V2B.

PHEVs could be used to address load levelling, regulation and reserve, research has found, and there are a number of benefits from using EVs to participate in DSM as DERs in a smart distribution grid.

Research has been done to look at the potential benefits of EVs as dynamically configurable dispersed energy storage, both in terms of supporting DSM and outage management initiatives. Most of the time, vehicles are parked at homes, in parking lots, on streets and in garages – the perfect time to leverage their battery capacity. In V2G mode, EVs could act as decentralized energy storage in a smart grid, acting either as a load or generator as required.

V2B mode works differently but ultimately serves the same goal of energy efficiency. In this situation, power is exported from the vehicle battery into a building – vehicle batteries serve as a generation resource for the buildings through a bidirectional power transfer through energy exchange stations at pre-determined times. The benefit would be a more reliable distribution system while providing economic benefits to vehicle owners and potentially reduce the purchase cost of the building's electricity.

DERs are parallel and stand-alone electric generation units located within the electric distribution system at or near the end user. DERs can be beneficial to both electricity consumers and utilities if the integration is properly engineered. While the centralized electric power plants will remain the major source of electric power supply for the future, a DER complement central power generation by providing incremental capacity to the utility grid or to an end user.

Installing a DER at or near the end user can also in some cases benefit the electric utility by avoiding or reducing the cost of transmission and distribution system upgrades. As one important technology used in configuring DER, energy storage technologies can deliver stored electricity to the electric grid or an end-user, which could be used to improve power quality by correcting voltage sags, flicker, and surges, or correct for frequency imbalances.

As with most vehicles, EVs spend most of the time sitting idle, so their battery capacity can be fully utilized during such times and serve as DER. When aggregated in sizeable numbers and capable to operate in the V2B mode, they could act as generator and even play an important role in outage management; their batteries could be used as emergency back-up power for commercial facilities or other large buildings.

V2B before V2G

V2B is a concept that is practically viable today because it is far simpler than V2G. Conceivable, V2B could be implemented within the next three to five years, while the horizon for V2G is farther out: It will likely take 10 to15 years to gain wide acceptance. One of the primary reasons V2B is likely to gain traction sooner is the availability of EVs in major cities due to early adopters. In the next few years there could be a critical mass of vehicles for aggregated use. And with the development of smart garages that can provide an interface between the transportation network and electric power system, the vehicle charging/discharging infrastructure and control system is available to make V2B not only viable, but economically attractive.

There are a number of key considerations that must be taken into account when implementing V2B, starting with batteries, which are one of the most important components of EVs. Research has shown that advanced battery technology is adequate to support most of the available vehicle models, while battery capacity depends on the electric range and the vehicle electric drive efficiency. However, there is still a great deal of uncertainty surrounding what is the most economical size and configuration of marketable EVs when comparing the battery pack size and technology, electric motor size and IC engine size.

Another critical factor in V2B implementations is data availability from a variety sources, including power system static data; real time topology information and load data; event data; location data, including that of the fault, the building which is out of electricity, and possible location of PHEV/EBV battery generation; availability and possible amount of generation; the status and performances of charging stations; and, the price of charge/discharge.

Both the V2G and V2B scenarios have issues, however. The value of having these idle EVs as an available power source to the grid must be balanced with the inefficiency of reverse power flow and the impact on battery life, which in turn raises issues of who will bear the cost of the battery warranty and replacement.

Mind Your Station

One of the key physical components that must be addressed is the energy exchange station for G2V and V2G. There are at least two forms these stations could take; the first one assumes that individual drivers plug in and charge their vehicle over a period of several hours, much like they plug in their smartphones. These stations would not be limited to their home; charging stations could be located at shopping malls, recreational areas, schools, and other locations frequently visited by drivers where their vehicles may sit unused for a minimum period of time.

However, instead of requiring drivers to plug into the grid and wait several hours to charge their batteries, battery exchange locations could be as ubiquitous as gas stations and automatically exchange discharged batteries with fully charged batteries, which would certainly be more appealing to drivers. This system of leasing batteries would alleviate consumer concerns about battery life and warranty while utilities would benefit from centralized control over charging and servicing the grid.

In likelihood, we will see a combination of these two approaches. Depending on the pricing and incentive structures in place, it may make sense for drivers to exchange batteries during long drives and plug in to a household plug at night.

The Road Ahead

In order for faster and significant adoption of EVs to occur and for them to be efficiently integrated into the power distribution system, a great deal of modeling of complex systems must take place as well, starting with the interactive performance of power and transportation systems. And while economic feasibility will play a large role in determining the growth rate of EV usage and effective integration into the power grids to realize the benefits of G2V, V2G and V2B, it's people who are in the driver seat: Widespread adoption EVs will place human vehicle operators at the intersection of power and transportation systems, so understanding human decision making within the context of EV usage will be a critical factor moving forward. Further research is needed to further develop the proposed concepts. Research organizations such as the National Science Foundation's Center 'EVs: Transportation and Electricity Convergence' are making contributions to bring the proposed concept to practical fruition.

About the Author

Dr. Mladen Kezunovic is the Eugene E. Webb Professor at Texas A&M University. A Fellow of the IEEE and IEEE Distinguished Speaker, Dr. Kezunovic is also a Technical Expert for the IEEE Transportation Electrification Initiative, specifically aimed at accelerating the development and implementation of new technologies for the electrification of transportation. Dr. Kezunovic is also the Director of the Smart Grid Center, Site Director of NSF I/UCRC "Power Engineering Research Center, PSerc", and Deputy Director of another NSF I/UCRC "Electrical Vehicles: Transportation and Electricity Convergence, EV-TEC".

Use of Custom-fitted Cover-ups to Reduce Power Outages and Mitigate Avian Electrocutions

By Nikki S. Heck, P.Biol. and Todd Sutherland, P.Eng.

Introduction

Wildlife, such as small animals and birds, has been a burden to utilities and system reliability for as long as the modern electrical grid has existed. The lack of attractive nesting areas in some landscapes combined with the inquisitive nature of birds means that electrical substations can attract an alarming level of bird activity. This activity can lead to electrocutions, costly repairs, lengthy outages, and in some cases, violation of wildlife related legislation.

AltaLink is Alberta, Canada's largest transmission service provider, operating and maintaining over 12,000 kilometres (7,500 miles) of transmission line and approximately 280 substations. The utility has considerable experience managing wildlife impacts on power systems with roughly 20 percent of all substation outages attributed to wildlife contacts (predominantly birds) on low voltage equipment. This is a significant increase over historical levels; the contribution of wildlife to substation outages has risen from 5 to 10 percent in the late 80s and early 90s to over 20 percent from 2003 through 2012 prompting the need for a solution (Figure 1).

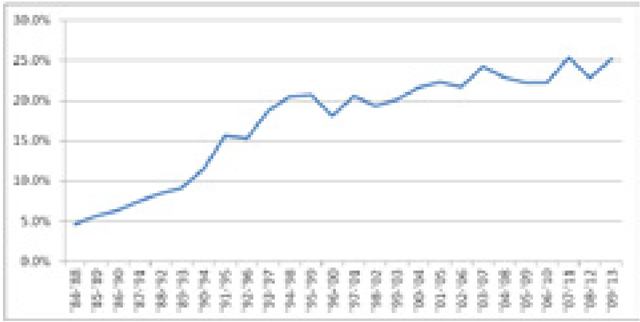


Figure 1: Percent of Substation Outages caused by wildlife contacts (5 year rolling average)

In an effort to prevent electrocutions and improve system reliability, AltaLink began testing a new, custom fitted cover-up product called Greenjacket. It is unique among other cover-up products because it is custom fitted to cover various equipment of all shapes and sizes. The product is made out of a highly dialectric, polyurea material that meets the IEEE 1656 industry standard for bird and animal cover-up.

Figure 2: A typical custom cover-up installation using Greenjacket products

Today, Greenjacket is now a formalized program and standard product, where all new substations are outfitted with the product during construction and existing substations are prioritized and retrofitted annually. The goal of the cover-up program is to improve the reliability of the transmission system while minimizing emergency call outs, costly outages to customers, consequential damage to equipment as well as protecting wildlife, including birds. The maintenance savings are derived from the avoidance of unplanned call outs, equipment repairs consequential to any wildlife caused outage, and customer outage costs.

Figure 3: Low-voltage connections and equipment pre-and post coverup installation. The underground connectors, dropout switch bases, lightning arrestors, pipe bus, and breaker bushings are all covered.

The Cost of Wildlife Caused Outages

Wildlife contacts and outages can have significant costs not only to electric utilities but also to the public, customers, and wildlife. A cost-effective solution for mitigating outages is often an easy sell to regulators and customers alike.

Such contacts can result in significant damage within a substation. Typical AltaLink repair costs range from $5,000 to repair or replace smaller equipment and components, such as insulators or arrestors, to as high as $80,000 to replace an entire 25 kV breaker. This is including both material and labour costs and is based on past experience. If the damage is significant a prolonged outage to make repairs is necessary and in some cases a mobile transformer may be required, at a minimum additional cost of $70,000. Additionally, there are costs associated with responding to the initial outage itself, which involves dispatching a crew to travel to the substation and inspect the site. Sending crews out to investigate an unplanned outage takes away from the day's planned activities and can result in cancelled or deferred work disrupting schedules and maintenance plans.

Despite the potential costs to the utility itself, in many cases the greatest impact of wildlife contacts are to interconnecting customers. For example, a one hour outage to an industrial customer with a 5 MW load valued at a conservative $15 per unserved kWh[1] results in a financial impact of $75,000. For even larger customers with sensitive loads and the highest of reliability demands, even a short duration outage can interrupt processes and production for much longer than the duration of the outage itself and have significant financial impacts.

The birds and animals themselves are directly impacted if they are injured or killed from the contact. Depending on the species, this may be considered a legal violation and may require reporting to provincial, federal or state enforcement agencies. At AltaLink, the most common species involved in equipment contacts are crows, ravens, and occasionally owls. Electrocutions involving non-owl raptors – i.e. hawks, eagles and falcons – are rare, as are electrocutions involving water birds. Substations in areas that are favourable habitat for crows and ravens, such as near industrial sites and landfills, typically experience more frequent contacts than substations in areas of less favourable habitat. AltaLink's substation that has historically experienced the most frequent bird caused outages is located directly across the street from a Class II landfill. This particular substation is subject to extreme bird activity and, as a result, has experienced 8 outages due to bird contacts in the previous 5 years.

Animals such as squirrels, raccoons and weasels can also be electrocuted, causing outages, when they enter the substation looking for shelter or food. These animal caused outages are often catalyzed by the small birds that nest in small cavities such as bus pipes (e.g., house sparrows), and on the undersides of the support beams (e.g., barn swallows). The predatory animals are electrocuted while trying to steal the eggs or young out of their nests.

Despite injury and loss of life, the number of birds electrocuted in substations is unlikely to have any impact on populations. The exception would be if an endangered or threatened species was electrocuted. The greatest impacts continue to lay with the electric utility companies themselves and the interconnected customers they serve.

Adopting Custom Cover-Up

AltaLink began experimenting with Greenjacket custom cover-ups in 2005 after continuing to experience high failure rates with off the shelf type products. Although custom cover-ups came at a higher cost, the volume of wildlife related outages was on the rise and a solution was needed. At that time the local company, Cantega Technologies, had yet to test their Greenjacket product in an in-service substation.

Immediate reliability improvements were observed in the substations with Greenjacket and AltaLink began to adopt the product more widely, all while working closely with the developer to continually improve the product design and application. What began as a spray on application inside an in-service substation, evolved into 3D modelling and manufacturing of the covers off-site.

All utilities, including AltaLink, need to perform maintenance and inspections on equipment on which cover-ups have been installed. Some inspection practices have to be altered on equipment with cover-ups. For example, when infrared scanning or Thermal Imagining is done, particular attention is paid to variances between the phases. When an obvious variance is observed, further investigation is warranted, which would include removing the cover-up and conducting a more detailed investigation. A strong advantage of precise fit cover-ups is that when they need to be removed for equipment maintenance or service, it can be done quickly and easily. Re-installation is simple and quick as precise-fit covers will always fit properly and completely cover potential contact points, eliminating all risk. AltaLink's experience is that re-installation of a cover typically takes a minute or less.

As a result of the success and continued evolution of the program and because the incremental cost and effort to install the product is minimal, AltaLink's current practice is to install Greenjacket cover-ups on all low voltage equipment at all newly constructed substations. To date cover-ups have been installed in approximately 80 of their 280 substations and the utility continues to target five installations at existing substations per year. This includes retrofits at sites with existing cover-up to either increase the coverage and/or replace older obsolete fittings.

Learnings

Through the partnership with Cantega, AltaLink was involved in the evolution and expansion of the product to include a wider range of custom fittings for greater coverage of low voltage equipment. Installation practices have improved considerably since the early 2005 trials through the investigation of wildlife contacts and learning what did and did not work.

The greatest challenges with the product are primarily related to installation deficiencies. If not installed correctly, the product may be ineffective in preventing contacts. Ensuring proper training of staff and contractors has proved to be particularly important to address this challenge, as is increased quality control and assurance practices.

Contacts can also continue to occur at sites where there is difficult equipment to cover, such as switches and airbreaks, or where gaps need to be left for bonding. Every instance of a bird finding a tiny spot in which to poke its beak provides an opportunity to learn how to better cover substation equipment. In this way, the standard remains a living document that is continuously improved upon.

Another challenge faced by AltaLink is difficulty in acquiring the necessary outages to install cover-ups. This is particularly an issue at higher load substations serving industrial customers with large production facilities where an outage is not an option. To overcome this challenge, AltaLink has tested and approved a new technique for installing cover-ups on energized equipment (Figure 4). Although de-energized installations are the preferred method, this technique allows for greater flexibility. It does however require careful planning and precise execution. On any energized installation, AltaLink staff work closely with Cantega's experienced hotline certified crews with safety as the primary focus.

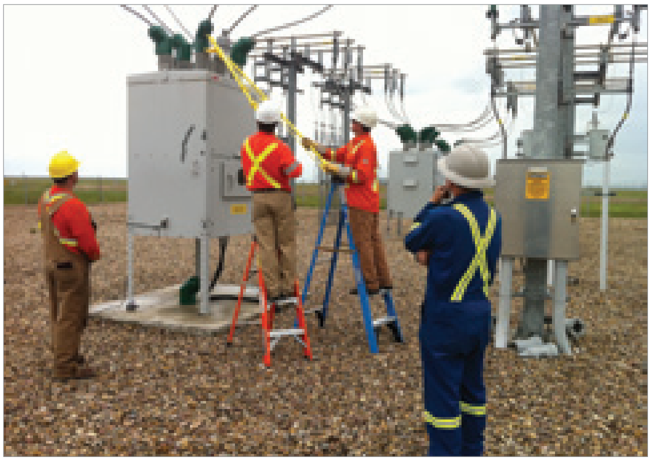


Figure 4: Energized installation using specialized hotline tools.

Effectiveness Evaluation

To date AltaLink's cover-up program has resulted in material and measureable improvements in reliability. To assess the effectiveness of the program a thorough examination and comparison of performance before and after the installation of cover-ups was performed; effectiveness evaluation is ongoing annually. When evaluating those stations which had a history of at least one wildlife related contact every two years, the frequency of contacts drops from 0.67 to 0.03 following the installation of cover-ups (Figure 5). This amounts to a 95 percent reduction in wildlife related contact, including those contacts that were not mitigated due to faulty and/or poor installation practices (Figure 6). This has in turn translated to improved customer performance and customer savings by reducing overall SAIFI (frequency of interruptions) by greater than 3 percent and SAIDI (interruption duration) by greater than 8 percent.

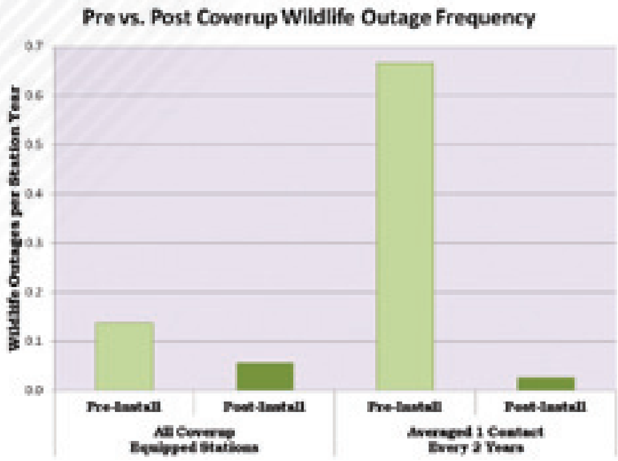


Figure 5: For stations which had a history of at least one wildlife related contact every two years

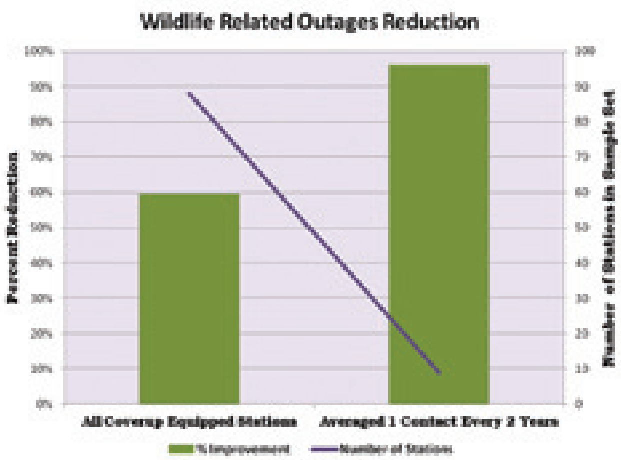


Figure 6: The green bars represent percent improvement while the Purple line indicates the number of stations in the sample set.

Cost Benefit Analysis

The benefits are clear. Not only is the program a win-win in terms of reducing bird electrocutions and the resulting outages and maintenance costs, it also results in significant savings to customers who expect highly reliable service. Performing a conservative Cost-Benefit analysis to the hypothetical example discussed earlier results in an internal rate of return of 17 percent and a payback of 7 years.

And, the effective service life of Greenjacket is well in excess of 20 years, so we consider this to be a long term, highly cost effective solution. With lower cost installations, such as on smaller or simpler sites, the return is even greater at 33 percent and a payback of 3.5 years! The analysis takes into account typical installation costs, outage rates, product effectiveness, and maintenance costs. It assumes the following: Site average of one contact every three years; Maintenance cost of $8,000 per outage; Product is 100 percent effective; Installation cost of $90,000-$180,000; Customer load is 5 MW valued at $15 per unserved kWh; and 2.15 percent Inflation rate.

Unique Solutions and Benefits

The benefits of working closely with a custom cover-up company don't end at outage mitigation. Birds will opportunistically nest in exposed cavities and small openings (e.g., substation bus pipes and gussets), which can lead to outage problems. In 2011, covers were designed for grounding reactors which have historically offered nesting opportunities for the Black-billed Magpie (Figure 7). A similar project in 2013 covered potential nest sites for the Great Horned Owl in a substation where a pair had been nesting for several years. Great horned owls will nest in open cavities where there is some overhead cover such as the gussets of support columns in air break structures. AltaLink installed covers at 30 of these sites in one particularly problematic substation (Figure 8). The flexibility of the company to tailor custom solutions to a variety of issues and impacts is a clear side benefit of the relationship.

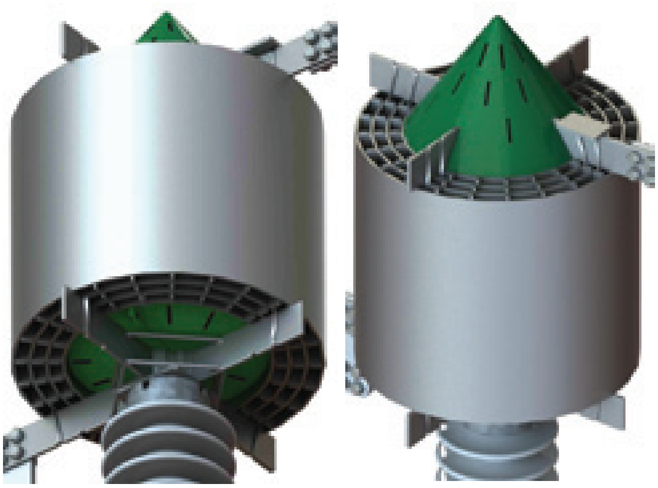


Figure 7: Grounding reactor, bottom and top view, used to prevent nesting by the Black-billed magpie.

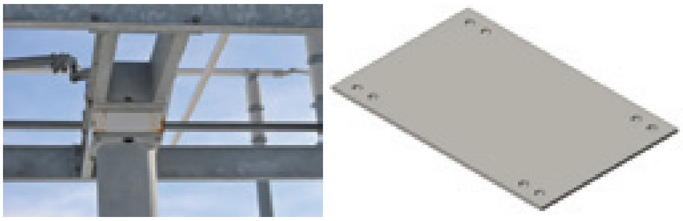


Figure 8: Gusset (left) and cover (right) to prevent nesting by Great Horned Owls.

Discussion

The impacts of wildlife caused outages and solutions are obvious. Mitigating wildlife contacts by even a fraction let alone upwards of 95 percent is a clear win-win scenario as wildlife cause unacceptably high volumes of outages resulting in service interruptions to customers and equipment damage.

To date, AltaLink's custom cover-up program has reduced wildlife outages by upwards of 95 percent at sites with installations, has reduced overall SAIDI by over 8 percent and SAIFI by over 3 percent, with material and measureable improvements in reliability performance.

The cover-ups have been such a success at AltaLink that in 2007 the program earned the President's Award of Excellence. The President's Award is an annual award to recognize the outstanding work and innovation of employees. The cover-ups also form an integral component of AltaLink's Avian Protection Plan (APP), a management system specifically designed to reduce bird impacts with electrical equipment and infrastructure.

Where solutions such as this exist, companies should be willing to adopt proven technologies to not only protect equipment and prevent outages but also to protect wildlife. Custom cover-up products such as Greenjacket offer a cost effective solution, as is clear from the results and cost-benefit analyses presented here. AltaLink would encourage any utility to review their wildlife caused outages and consider a custom solution.

About the authors

Nikki Heck is a Professional Biologist working in the electric utility industry in Alberta, Canada. She has been employed by Alberta's largest transmission service provider, AltaLink, since 2004 and as part of her role, wrote and implemented Canada's first Avian Protection Plan. Nikki has a Master's degree from the Faculty of Environmental Design at the University of Calgary where her thesis work was conducted on avian interactions with transmission lines.

Todd Sutherland is a Professional Engineer working in the electric utility industry in Alberta, Canada. He has been employed by Alberta's largest transmission service provider, AltaLink, since 2007 and is currently the chair of the Canadian Electricity Association (CEA) Committee on the Collection of Outage Statistics (CCOS). Todd has Bachelor's degrees in Electrical Engineering and Computer Science from the University of Saskatchewan.

[1] Interruption Cost of a 1 hour interruption to Medium and Large Commercial and Industrial Customers is US$2008 from Estimated Value of Service Reliability for Electric Utility Customers in the United States – Ernest Orlando Lawrence Berkely National Laboratory Study June 2009.

Leveraging AMI Data for Distribution Asset Management

By Dr. Siri Varadan, P.E.

The business case for AMI deployment has often been made palatable to the regulators on the basis of widespread business benefits for the utility and the ratepayer. While present deployments have mostly just replaced the traditional 'dumb' meter to serve its original purpose, as a cash register, much of the collected data remains to be exploited. This data may be used, readily in most cases, in a variety of applications benefitting distribution operations, planning, and management of utility distribution assets. When combined with data from other sources, one may develop unique insights into the power system, its comprising assets and their workings. Data driven asset management is the key to realizing the full benefits of AMI deployment.

Asset Management for the Distribution System

Asset Management is the science, and art, of making the necessary financial investments in the grid to either sustain, or improve, an observed level of performance. From an electric utility's perspective, asset management is a broad topic area which includes generation, transmission and distribution assets. This article remains focused on the applications of Asset Management for the distribution system.

Distribution asset management helps utilities achieve the best *return* related to the performance of the individual assets comprising the distribution system. Typical measures for distribution asset performance include:

- Availability - expressed in terms of time on an annual basis
- Failure rate or frequency of failure - on an annual basis
- Mean time for repair/replacement
- Mean time between (or to) failures
- Outage costs – including loss of revenue, repair/replacement cost and societal costs

The computation of these performance metrics is based on historical data, which is often incomplete, inaccurate or strewn across the utility enterprise in multiple databases in a variety of formats. Current utility practices require regulated utilities to report metrics on a system wide or regional, as opposed to individual assets, basis. As a result, very little meaningful, or actionable, intelligence may be obtained about individual assets. In many cases, a high percentage of the outages are recorded with a cause code of 'unknown.' This leaves much to be desired in terms of asset intelligence.

In asset management, the key questions to ask have to do with the identification – and location – of problem assets, the nature of the problems characterized by their performance (reliability, overloads etc.) and the various data sources to access to develop a comprehensive understanding of the health of individual assets comprising the power system. The investment philosophy is based on undertaking suitable actions – repair, refurbish, replace – based on asset condition while minimizing associated failure risks. 'Run to failure' is an acceptable and widely used maintenance strategy for assets of low criticality although there are no uniform or universally accepted definitions for criticality.

To be most effective, Asset Management must be based on sound engineering knowledge, financial expertise and a solid foundation of data analytics. Investment decisions must be justifiable, repeatable, and consistent.

Distribution System Data Analytics

The distribution system plays a vital role in the energy value chain as it forms the last-mile and final link to the customer. It is also the part of the system that has the highest losses (both technical and non-technical, i.e., theft), the most number of discrete components (making it difficult to model for analysis) and the highest number of reliability issues comparatively (measured in terms of frequency and duration of outages). With ongoing efforts for AMI deployment, the distribution system will also have the most data based on the number of sensors deployed, customer counts and the granularity of measurement in each case. With the growth of distributed generation resources connected to the distribution system and resulting two-way power flows, there is no doubt that the distribution system will also see the most change in its intended design and future use.

Traditionally, the distribution system was scarcely monitored, mainly due to technology cost and need considerations. However, with the cost of sensors and IEDs dropping and the deployment of AMI, the distribution system has the distinction of generating 'Big Data.'[1] AMI data typically consists of interval data (at a specified rate of sampling, typically at least hourly for revenue collection purposes) of demand (kW) and other event data for a given customer. The Meter Data Management System (MDMS) hosts meter data from all customers in a central location for use in mainly revenue oriented applications (billing, settlement, etc.) for now. This data could be leveraged further to applications to describe present conditions and make predictions about the power system.

AMI data may be further leveraged by combining it with other sources of data – topology, for example – to gain unique insights. By aggregating data from a set of customers who are all served by a common distribution transformer, for example, it is possible to make inferences about the transformer's performance. It is also possible to compute flows – and hence overloads and other reliability metrics like availability and number of failures in a given time interval and garner intelligence into the asset's operation and condition. The data may be used to measure and benchmark asset performance with the objective of determining asset health, which in turn, could be combined with asset criticality to establish a measure of risk to guide asset investments. In short, AMI data, in combination with other data may be used to effectively implement asset management at the distribution level. These other sources of data could include SCADA data (historical operational data), maintenance data (including inspections), vendor catalogs, benchmark data, outage data, DMS and distribution automation (DA) data, and data from on-line condition monitoring.

Three key opportunities to utilize AMI data for distribution asset management include:

1. Distribution Loss Analysis
2. Distribution Transformer Monitoring and Health Indexing
3. Complete Feeder Reliability Analysis

These opportunities look outward from a substation and focus on losses, loading and reliability based on available AMI data measured at the customer service delivery point(s), yielding considerable 'bang-for-the-buck.' Table 1 describes these applications and their data requirements at a high level.

Opportunities to Use AMI Data	Description	Additional Data Utilized*
Distribution Loss Analysis	Identify trend of loading on feeders, analyzing potential breakdown of theft and line losses (Where, How much) and notify user.	Distribution SCADA or Pi Historian, GIS/CIM feeder connectivity, OMS or DMS operational data, CIS data, CMMS, Vendor Catalogs
Distribution Transformer Monitoring and Health Indexing	Compute, trend and notify user of excessive feeder and transformer loadings over time (Which one, How much, How long)	
Complete Feeder Reliability Analysis	Track, trend and predict feeder reliability using asset health indicators for key feeders	

*SCADA = Supervisory Control & Data Acquisition; CIS = Customer Information System; CIM = Common Information Model; GIS = Geographical Information System; OMS = Outage Management System; CMMS = Computerized Maintenance Management System; MDMS = Meter Data Management System; DMS = Distribution Management System

Distribution Loss Analysis

Losses resulting from technical and non-technical causes are an important issue in distribution systems. Calculation of technical losses is difficult due to inconsistencies in distribution system modeling, load profiles and their associated granularity. Typically load profiles are constructed based on assumptions and limited data (typically measured at the substation or feeder head). AMI data can help in developing improved load models.[2] These improved load models could be used in a load flow program to calculate the technical losses on a highly granular basis – say, every 15 minutes – and then aggregated suitably to provide a measure of losses on a monthly or annual basis. These losses may then be compared with losses calculated from revenue calculations using AMI data. The comparison when done on a granular basis – per feeder, for example – can help identify the location and amount of loss.

A visual description of how AMI data may be used to compute feeder losses is shown in Figure 1 where feeder losses associated with a given substation are aggregated (over the time period of analysis) and displayed using a dark color (heat-map) on the electrical one-line diagram. Substations whose feeders have high losses are shown by the red dot in relation to other substations on a geographic map. Various levels of zoom are permitted along with a selection of layers for purposes of displaying different levels of granularity of the results.

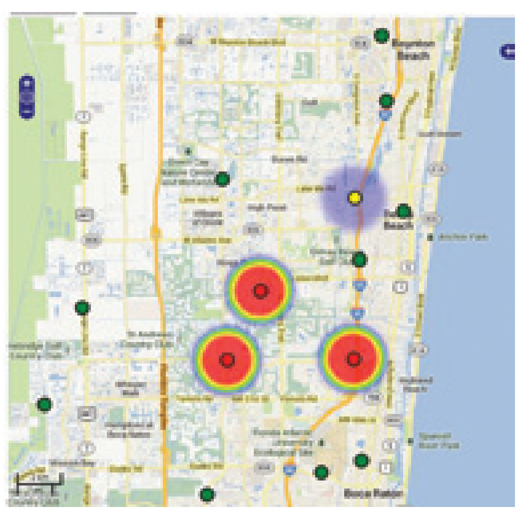


Figure 1. Feeder Losses Shown Using Heat-maps

Distribution Transformer Monitoring and Health Indexing

Distribution transformer monitoring has been challenging in the past because of the lack of availability of sensory data at the right location. However, with the availability of AMI data and topological connectivity, it is possible to aggregate AMI readings in time across all customers fed off the same distribution transformer. The aggregated reading provides a measure of the true loading of the transformer. Comparison of the aggregated loading versus name plate readings then allows for the determination of frequency and duration of overloads – making it now possible to monitor individual transformers. Similarly, it is possible to establish outage statistics for a transformer based on AMI data from customers fed off that transformer.

Monitoring these transformers can provide insights into the pro-active actions that need to be taken. For example, a transformer that is overloaded all the time may need to be upgraded with one of higher rating either from the warehouse or just swapped with an existing transformer that is over rated for its present location. This shifting of capacity can ensure optimal utilization of assets.

Figure 2 displays transformer health based on the weighted average of frequency and duration of overloads over the analysis period. In the figure, transformers are shown using triangle symbols with their fill-in colors representing various heath ratings. Transformers with a health rating of 'Good' are shown in green, transformers with a health rating of 'Moderate' are in yellow and transformers that 'Need Attention' are shown in red. The tab on the far right shows the health index of the substation (0.52 on a scale of 0 to 1, lower values indicating worsening health), which is an aggregation of the health indices of all assets associated with it. On the far right bottom, the raw data associated with the selected transformer is shown. These data are used in the determination of the health index of the selected transformer (0.4479).

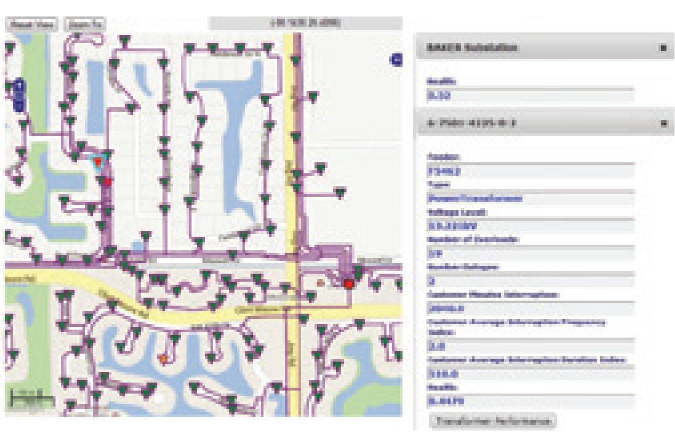


Figure 2. Transformer Health at a High Level

Figure 3 shows the details of the transformer health index calculation. Overloads (number and duration) along with outage data (number and duration) are taken into account in the computation of the index that is a proxy for transformer health. The figure shows the summary for all transformers in the test power system.[3]

Figure 3. Data Visualization for Transformer Health Calculation

Complete Feeder Reliability Analysis

With the availability of AMI data, it is possible to calculate reliability metrics based on frequency and duration of service interruption at the point of service/delivery. These metrics are a true measure of what the customer experienced in terms of loss of service in contrast to the numbers calculated by the utility, which is on a system wide basis, averaged across all customers. Likely, these AMI data based metrics will spur a debate on how reliability metrics need to be calculated.

By data aggregation, the metrics calculated at the service drop off may be used to calculate reliability metrics at the transformer level. These may in-turn be aggregated to calculate metrics for the feeder and the substation. Figure 2 above indicates the reliability of the transformer in terms of numbers of outages (2) and duration, i.e., 510 minutes (indicated by the tab in the far right, near the bottom), which accounts for a total of 2040 customer minutes of outages.

Using the same data aggregation logic, it is possible to calculate reliability indexes for the feeder. Clearly to accomplish this, the circuit topology must be known along with all the underlying AMI data. It is also possible to characterize feeders by risk of failure knowing their associated reliability and the criticality of the loads they serve. This prioritized risk profile could serve as a guide for trouble shooting, asset investments and predictive actions related to maintenance and/or asset replacement.

As a practical matter, it is important to identify and rectify data accuracy issues. These data issues, if left unresolved, could lead to unreliable results that might lead one to doubt the benefits of the AMI data mining efforts. Lessons learned from past implementations show a threshold level of trust has to be reached before users adopt any new technology without reservation. Data analytics is no exception.

Closing

While AMI data serves the primary purpose of revenue calculation, it can serve multiple other purposes by itself. When combined with other data sources available within the utility enterprise, AMI data can provide unique insights into such areas as theft detection, loss identification, transformer monitoring, asset health indexing, feeder reliability calculation, substation ranking (by various criteria), and risk management. These insights can help utilities realize the full benefits of AMI deployment and other smart grid investments. Combining AMI data analytics with graphic capabilities provided by third party vendors, such as Google, for example, allows data visualization in a realistic sense. Calculations of various data analytics can be presented in the form of layers on top of a geographically based one-line diagram of the power system as shown here.

References

[1] Per the Forrester et al definition, big data is characterized by the four Vs – Velocity (speed at which data are being accrued, Variability (subject to multiple interpretations), Variety (in the number of possible formats, and Volume (amount of data that needs to be stored, sorted and searched).

[2] AMI data will play a large role in accurate determination of loads in the light of anticipated two-way flows in distribution feeders as a result of increasing levels of penetration of distributed generation sources.

[3] The test power system is the IEC-61968 test power system. AMI data was simulated based on customer profiles and system characteristics. The simulated data included outages and overload conditions to reflect realistic operational conditions.

About the author

Dr. Siri Varadan, PE, is a Vice President at UISOL (an Alstom company), where he leads the Asset Management Practice. Dr. Varadan holds BS, MS and Ph.D. degrees in Electrical Power Engineering and specializes in asset management, data analytics and IT integration for electric utilities with a focus on T&D systems. He is a senior member of the IEEE and a member of the Institute of Asset Management.

Three Critical Areas for Ensuring a Successful NERC Audit in 2014:

Reliability Standard Audit Worksheet (RSAW) Preparation, Narratives, and Evidence

By Bob Biggs

The 2014 NERC audit season is soon upon us. While some Registered Entities used Q4 2013 to get a jumpstart on audit preparations, others will return from the year-end holidays either never having been through an audit or having years pass since their last sit-down with Regional auditors. To help ensure a successful NERC audit, this article focuses on 3 critical areas within Reliability Standard Audit Worksheets – preparation, narrative development, and evidence documentation. Our examination of these areas is supported by RSAW examples, best practices, and the experience of a Generation Operator whose proactive RSAW preparation was key to ensuring a successful audit.

RSAWs are the Road Map of Your Compliance Program

As Reliability Standard Audit Worksheets (RSAWs) are used by NERC Compliance Enforcement Authorities (CEAs) when auditing Registered Entities, the RSAW is your primary method of communicating your entity's internal compliance process, controls, and evidence. As such, RSAWs are the 'make it or break it' component of your audit – they are the road map of your compliance program as:

- they determine whether or not sufficient evidence supports your compliance with applicable NERC standards and requirements
- they are the tool for identifying non-compliances and potential violations
- they serve as a public record of your audit, and they help you prepare for an audit and, if maintained up-to-date ("Living" RSAWs), provide for on-going compliance maintenance.

5 Common RSAW Challenges

Over the past few years, Regional and Registered Entities have been sharing NERC audit experiences and best practices. While helpful, they are often broad discussions of "Here's what was required, here's what we did, make sure you address that" type of presentations.

However, when Notification of Audit letters arrive in your inbox defining the audit scope and sub-requirements, those PowerPoint discussions simply don't go deep enough into the real challenges of responding to RSAWs. While our readers can undoubtedly add to our list, some common RSAW challenges you may face include:

5 Common RSAW Challenges

RSAW Knowledge Gaps Between Audits	Completing RSAWs accurately can be challenging due to changing NERC requirements, critical knowledge lost through retirement and job changes, and escalating resource constraints. With the exception of spot checks, regulatory audits of Registered Entities (RE) are typically 3 or more years apart. As a result, there may not be an on-going process of maintaining RSAWs up–to-date – thus preventing dynamic or 'living' compliance.
The Difficulty of RSAW Preparation	RSAWs demand adherence to exacting policy, procedure, narrative, evidence, formatting, and submittal package requirements. They are not easy – or quick – and require exacting attention to detail. Ensuring successful RSAW preparation and submittal has required hundreds of hours for some Registered Entities.
Inconsistent Standard Applied to RSAW Narratives During Regional Audits	Consistent measure applied to RSAW narratives, evidence type, or submittal across the eight Regional Entities is often challenging. Registered Entities in multiple jurisdictions must ferret out Regional differences and requirements. Auditors often rely more upon evidence provided and discussions or questioning to determine compliance instead of the RSAW narrative. Expectations for RSAW narratives vary by the audit team. (NERC and the Regional Entities recognize this and are working to address it).
No Central Repository for Files, Folders, & Evidence	Often, compliance documentation is archived in various Word documents, stand alone Excel files, personal emails, PDFs, phone texts, voice mails, and legacy enterprise systems – few of which are searchable, available anywhere/ anytime, or electronically linked. Often, there are multiple versions of policies and procedures, narratives, and evidence, and RSAWs may be out of date, differing in format, and/or content. Without a central compliance management system, Registered Entities must often 'hunt down' and verify hundreds of documents and information artifacts (there is rarely a 'map' of where things are scattered) and create a standard management system.
Inconsistent RSAW Submittal Package Requirements	RSAWs often must be submitted via specific versions of Internet Explorer, Mozilla Firefox, or Chrome. Interfaces to EFT Server / Client interfaces may be required, along with specific applications like Java Runtime Environment V6. File structure and naming conventions can be confusing and vary by Regional Entity. (In future articles, we will address RSAW submittal package requirements).

Getting Down to the Real Nitty-Gritty: RSAW Preparation, Narrative, and Evidence Documentation

Audit schedules are published by the Regional Entities each year, with Initial Notification Letters and Compliance Surveys typically sent six months in advance of the audit date. Detailed audit letters are often sent three months in advance of the audit.

Well-prepared RSAWs demonstrate a company's commitment to a thriving 'compliance culture' in advance of the actual audit date. Being prepared 30 to 60 days ahead of these milestones is recommended. Here are some areas to think through (preparing to prepare) before making assignments, gathering files, and writing responses:

Step 1: RSAW Preparation – Things to Consider Upon Audit Notification

When should we start preparing?

- When is the audit?
- What are our expectations for RSAW preparation and submittal?
- When should we kick off the RSAW process?

Where should we start?

- Do we have multiple, decentralized business areas that are involved in the audit?
- Do our facilities cross Regional Entity jurisdictions?
- Have we delegated any reliability standard requirements to another entity?
- Have any reliability standard requirements been delegated to us from another entity?
- Have the standards changed?
- Have the RSAW requirements changed – Do we have the most up-to-date versions?
- Have the Regional Entities' expectations for RSAW completion changed?
- What is our communication plan with the regulator?

Who needs to be involved?

- Who has previous RSAW and audit experience?
- Who understands Regional Entity differences?
- Who are specific Subject Matter Experts?
- Who should be on the RSAW prep team?
- Who needs training and indoctrination on the audit and RSAW development process?

How will we manage the documents?

- What policy and procedure documents, spreadsheets, emails, messages, etc, are needed for this RSAW?
- What are the RSAW formatting requirements?
- How and where are we managing the process electronically?

Step 2: RSAW Narrative Development

Now that you've thought through your RSAW approach and located the appropriate documents, you are ready to develop clear and concise RSAW narratives – narratives that support compliance, while not providing unrelated or superfluous information. Here are four principles to keep in mind as you do:

1. Clarity: Auditors may only look at evidence rather than reading the RSAW narrative, or the Auditor may read the paragraph narrative and may or may not understand your meaning. Your narratives must be very clear and concise.

Three Critical Areas for Ensuring a Successful NERC Audit in 2014: Reliability Standard Audit Worksheet (RSAW) Preparation, Narratives, and Evidence

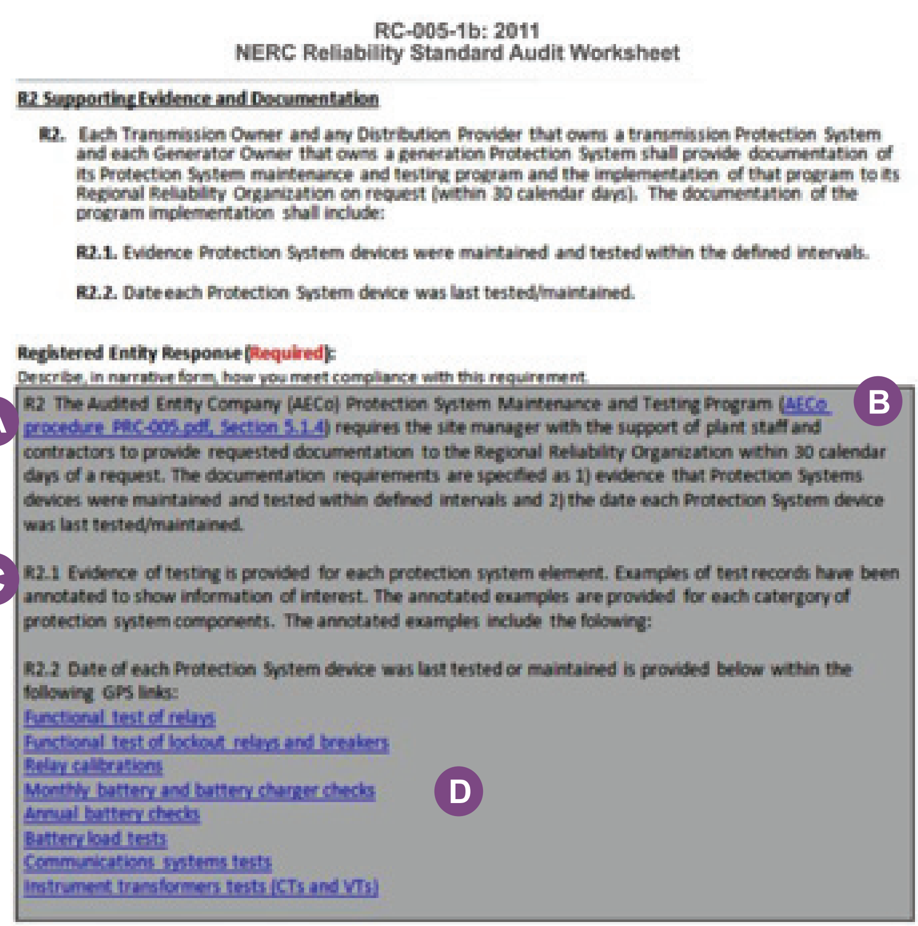
2. Consistency: Be consistent when a document is referenced repeatedly or throughout multiple RSAW narrative responses in terms of naming conventions and file descriptions.
3. Accuracy: Is the narrative accurate? Did content get overlooked or embellished?
4. Full Disclosure: All narratives and documentation must be complete – regardless if they are favorable or not. Remember to include compliance by others to whom you have delegated compliance.

Next, RSAW narrative requirements have been changing – requiring Registered Entities to more clearly depict the linkages between the standards, requirements, and narratives to specific evidence in the requirement.

To illustrate these points, below are two examples of RSAW narratives across two years - as narrative requirements change - with best practices noted with letters:

Best practices

A. Narrative responses should follow the sequence of the requirements and sub-requirements – not restate them.
B. Procedures that support RSAWs should contain sufficient detail to tie to the NERC standard or requirement.
C. Elaborate in concise detail how you comply with the requirement. Provide descriptions of policies and procedures with reference to evidence.
D. Well organized and clearly presented information facilitates the Auditor's verification process and minimizes Requests for Additional Information.



RC-005-1b: 2011
NERC Reliability Standard Audit Worksheet

R2 Supporting Evidence and Documentation

R2. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include:

R2.1. Evidence Protection System devices were maintained and tested within the defined intervals.

R2.2. Date each Protection System device was last tested/maintained.

Registered Entity Response (Required):

Describe, in narrative form, how you meet compliance with this requirement.

A

B

R2 The Audited Entity Company (AECo) Protection System Maintenance and Testing Program (AECo procedure PRC-005.pdf, Section 5.1.4) requires the site manager with the support of plant staff and contractors to provide requested documentation to the Regional Reliability Organization within 30 calendar days of a request. The documentation requirements are specified as 1) evidence that Protection Systems devices were maintained and tested within defined intervals and 2) the date each Protection System device was last tested/maintained.

C

R2.1 Evidence of testing is provided for each protection system element. Examples of test records have been annotated to show information of interest. The annotated examples are provided for each catergory of protection system components. The annotated examples include the following:

R2.2 Date of each Protection System device was last tested or maintained is provided below within the following GPS links:

Functional test of relays
Functional test of lockout relays and breakers
Relay calibrations
Monthly battery and battery charger checks
Annual battery checks
Battery load tests
Communications systems tests
Instrument transformers tests (CTs and VTs)

D

Operator's Proactive Approach to RSAW Management ensured no NERC Audit 'Surprises'

Nelson Industrial Steam Company (NISCO) provides 260 MWh of electricity to areas of the Southeast U.S. In April of 2011, the Southeast Electric Reliability Council (SERC) notified NISCO of their first NERC audit. SERC's detailed Audit Compliance Letter listed eight standards that would be audited, along with review of 58 sub-requirements, evidence of an Internal Compliance Program, and a current organization chart.

Prior to SERC's notification, NISCO recognized the importance of proactively organizing Reliability Standard Audit Worksheets (RSAW) policies, procedures, and evidence documentation well in advance of the audit period.

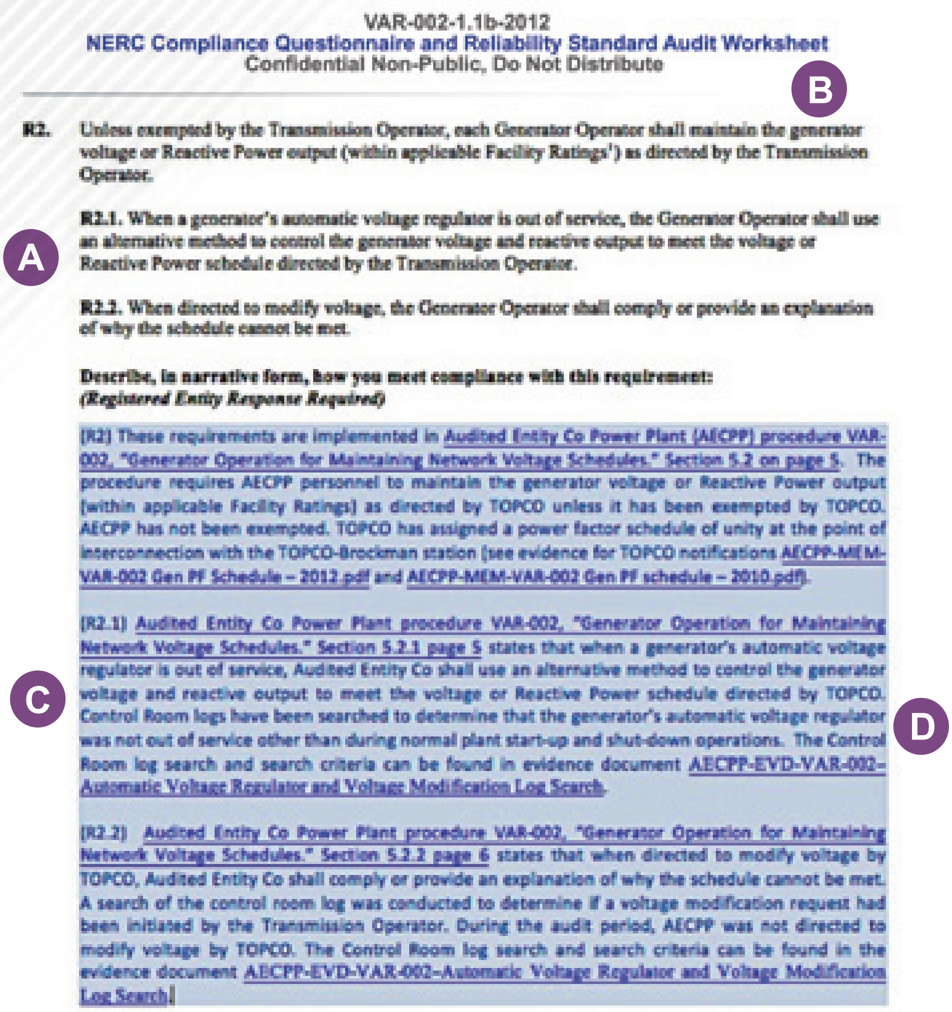
"As NISCO's Compliance Manager," says Mr. Shelley Hacker, NISCO's Site Operations Manager, "I have found that accurate, complete, and concise RSAWs are essential to my success during an audit cycle. At audit time, we want no surprises.

"Audit success should be based upon the sum of many small efforts, repeated day in and day out, and not just prior to an audit's conduct," continued Hacker. "Our audit preparation required hundreds of hours, but we were not overwhelmed because of our early engagement and a defined internal compliance program. This experience highlighted the following factors as being essential for ensuring the quality of our RSAW responses, the supporting audit package, and ultimately successful audit:"

- Identify the applicable reliability standards and requirements applicable to registration as a Generator Owner.
- Assign Subject Matter Experts for each NERC Reliability Standard and Requirement.
- Define the document file structure and file naming before beginning the RSAW response process.
- Update required policies and procedures and maintain up-to-date versions.
- Develop accurate and concise RSAW compliance narratives that support compliance with each requirement and sub requirement, and that include the rationale for the conclusions reached, yet do not provide unrelated or superfluous information.
- Link appropriate evidence to each RSAW requirement or question's narrative and summary of evidence tables.
- Assemble all RSAWs and audit submittal information in the manner prescribed by the regional entity – as it is not always consistent between audit teams or regional entities.
- Ensure that appropriate resources are applied throughout the organization to support day-to-day compliance activities, as well as to support audits.
- Use a compliance-specific web-based document management as a central repository to streamline the RSAW process, link all electronic documents and automate the RSAW Package Submittal process.
- Maintain up to date RSAWs between audit activities for ongoing compliance management.

Audit Results every Registered Entity Strives For

The SERC audit team thoroughly reviewed documentation provided by NISCO. Data, information, and evidence submitted in the form of policies, procedures, emails, logs, studies, data sheets, etc., were validated, substantiated, and cross-checked for accuracy as appropriate. As a result of NISCO's early and proactive RSAW preparation, SERC's onsite audit of NISCO was highly successful.


VAR-002-1.1b-2012
NERC Compliance Questionnaire and Reliability Standard Audit Worksheet
Confidential Non-Public, Do Not Distribute

B

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings[1]) as directed by the Transmission Operator.

A

R2.1. When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.

R2.2. When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

Describe, in narrative form, how you meet compliance with this requirement:
(Registered Entity Response Required)

[R2] These requirements are implemented in Audited Entity Co Power Plant (AECPP) procedure VAR-002, "Generator Operation for Maintaining Network Voltage Schedules." Section 5.2 on page 5. The procedure requires AECPP personnel to maintain the generator voltage or Reactive Power output (within applicable Facility Ratings) as directed by TOPCO unless it has been exempted by TOPCO. AECPP has not been exempted. TOPCO has assigned a power factor schedule of unity at the point of interconnection with the TOPCO-Brockman station (see evidence for TOPCO notifications AECPP-MEM-VAR-002 Gen PF Schedule – 2012.pdf and AECPP-MEM-VAR-002 Gen PF schedule – 2010.pdf).

C

D

[R2.1] Audited Entity Co Power Plant procedure VAR-002, "Generator Operation for Maintaining Network Voltage Schedules." Section 5.2.1 page 5 states that when a generator's automatic voltage regulator is out of service, Audited Entity Co shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by TOPCO. Control Room logs have been searched to determine that the generator's automatic voltage regulator was not out of service other than during normal plant start-up and shut-down operations. The Control Room log search and search criteria can be found in evidence document AECPP-EVD-VAR-002-Automatic Voltage Regulator and Voltage Modification Log Search.

[R2.2] Audited Entity Co Power Plant procedure VAR-002, "Generator Operation for Maintaining Network Voltage Schedules." Section 5.2.2 page 6 states that when directed to modify voltage by TOPCO, Audited Entity Co shall comply or provide an explanation of why the schedule cannot be met. A search of the control room log was conducted to determine if a voltage modification request had been initiated by the Transmission Operator. During the audit period, AECPP was not directed to modify voltage by TOPCO. The Control Room log search and search criteria can be found in the evidence document AECPP-EVD-VAR-002-Automatic Voltage Regulator and Voltage Modification Log Search.

Best Practices

A. Elaborate in concise detail how you comply with the requirement. Provide descriptions of policies and procedures with reference to evidence.
B. Procedures that support RSAWS should contain sufficient detail to tie to the NERC standard or requirement.
C. Elaborate in concise detail how you comply with the requirement. Provide descriptions of policies and procedures with reference to evidence.
D. Well organized and clearly presented information facilitates the Auditor's verification process and minimizes Requests for Additional Information.

In both examples, notice that the author avoided immaterial content that, while related, is not applicable or out of scope. This may include referencing data, policies, or procedures that don't support compliance to the Standards or sub-requirements and avoiding assumptions and 'interpretations' of the standards – unless they are material and can be validated by evidence. The author also made sure that all documents were the final and approved versions and that un-approved content was not overlooked.

Step 3: RSAW Evidence Best Practices

Every RSAW requires submission of an evidence matrix that validates your compliance narrative. Your evidence needs to be carefully organized, accurate, and citations linked to specific requirements and sub-requirements within your narrative.

To illustrate this, below is an example of evidence best practices for the 2012 VAR-002.1.1b / Generator Operation for Maintaining Network Voltage Schedules RSAW shown above:

R2 Supporting Evidence and Documentation

Response: *(Registered Entity Response Required)*

Provide the following:
Document Title and/or File Name, Page & Section, Date & Version

A

B

Title	Date	Version
R2 AECPP procedure VAR-002, Generator Operation for Maintaining Network Voltage Schedules, page 5, section 5.2 (AECPP-PRO-VAR-002 R03.pdf)	7/15/2013	Rev. 3
R2 Western TOPCO Transmission System (SPP Region), AECPP, Generator Power Factor Schedules (AECPP-MEM-VAR-002 Gen PF Schedule 2012.pdf)	3/16/2012	N/A
R2 TOPCO issued power factor schedule (AECPP-MEM-VAR-002 Gen PF schedule – 2010.pdf)	12/27/2010	
R2.1 AECPP procedure VAR-002, Generator Operation for Maintaining Network Voltage Schedules, page 5, section 5.2.1 (AECPP-PRO-VAR-002 R03.pdf)	7/15/2013	Rev. 3
R2.1 AECPP-EVD-VAR-002–Automatic Voltage Regulator and Voltage Modification Log Search	7/12/2013	N/A
R2.2 AECPP procedure VAR-002, Generator Operation for Maintaining Network Voltage Schedules, page 5, section 5.2.2 (AECPP-PRO-VAR-002 R03.pdf)	7/15/2013	Rev. 3
R2.2 AECPP-EVD-VAR-002–Automatic Voltage Regulator and Voltage Modification Log Search	7/12/2013	N/A
R2Q Attestation (AECPP-ATT-VAR-002- Voltage Schedules Attestation.pdf)	08/08/2013	0

C

NERC Compliance Questionnaire and Reliability Standard Audit Worksheet

Best Practices

A. The date/revision should be indicated as applicable.

B. Evidence files should be developed so as to clearly indicate what the evidence file is by just reading its title as it relates to the RSAW narrative.

C. The files in this table are linked directly to the files so that the evidence can be viewed by simply 'clicking' on the file name.

RSAW Next Steps

Once the RSAW narrative and evidence components are complete, conduct a detailed final review with all Subject Matter Experts:

- Was the document spell-checked?
- Are all narratives and evidence linked?
- Is anything missing?
- If completing the RSAW for multiple sites, were there any changes to versions of the RSAW that were missed?
- Did you have someone with strong editing skills check the document for the required formatting?
- Did you archive all compliance documentation in a central repository so that each RSAW can become a 'living' document easily kept up to date?

Submittal Package Requirements

Once your RSAW compliance narratives and evidence validation are complete, it's time to ready the RSAW package for electronic submittal. In future articles, we will discuss RSAW Submittal Package requirements – as they are worthy of their own examination.

About the author

Bob Biggs has more than 35 years of utility experience in generation plant operation and maintenance (fossil, hydro, nuclear, and wind), protective systems, self-assessment programs, facility ratings, and regulatory compliance. He deeply understands the regulatory lifecycle of NERC standards, development, regulatory policies and procedures, Regional Entity audits, findings, enforcement, and mitigation. Formerly the head of Entergy's Electric Reliability Standards Corporate Compliance Division, Bob is the Services Manager and currently serves as Office of NERC Compliance Manager for Certrec – a leading regulatory compliance expert that helps utilities manage the regulatory process to their advantage through a suite if Internal Compliance Program solutions. For more information please visit *www.certrec.com*

Big Data's Big Leap: Energy Providers Invest in SAP HANA to Enhance Data Insights

By Dr. Werner Hopf

The Big Data Jolt

Few would argue that the age of Big Data has arrived. The promise of previously unavailable insight and analysis is a driving factor behind the Big Data proliferation, and with good reason. When was the last time senior decision-makers from across a utility's business unit – from finance and marketing to product development and sales all the way up to the C-suite – were universally so enthusiastic, excited, and eager to leverage what has been, until recent years, an intangible resource?

The energy industry is among those which have fully embraced the concept of Big Data with gusto – and why not? Virtually every aspect of the operation creates data which can be saved, culled and analyzed to mine important business intelligence that assists with future decision-making by identifying business opportunities and locating expensive inefficiencies. Big Data can help break down sales trends, find patterns through customer service interactions, weed out waste from the supply chain, and even help to optimize cash flow by optimizing important business processes like procure-to-pay and order-to-cash.

However, when utilities approach the task of effectively managing Big Data, a substantial challenge quickly arises – there's simply too much of it. Think about this: every transaction, interaction, and electronic decision produces data. Every moment a customer's electric meter is ticking, data is being produced. Some data is much more valuable to energy providers than other data, and it becomes problematic when there is too much data present in an active database. Data overload can easily choke processing speeds of systems and networks, creating performance bottlenecks that limit access to important information. Another issue is the speed, and depth, at which analytics can be performed. More data to process means a bigger picture view and, in theory, better insights delivered to executives and decision makers throughout the organization. Despite rapid advancements in analytics in recent years, technology is only now reaching a point where truly massive data caches can be analyzed in real-time.

SAP HANA: Next Generation Insight

Now, there is a new in-memory database platform available to energy providers and others who operate in an SAP environment, and it boldly promises to help fulfill the potential of Big Data at a level previously unattainable with existing data management technologies. That platform is SAP HANA. SAP HANA is an in-memory database designed to perform real-time analytics and to develop and deploy real-time applications utilized by large organizations to run the business. With such an emphasis on real-time, one promise of SAP HANA lies in its speed. SAP notes that early adopters of the SAP HANA platform have experienced query performance increases by as much as 100,000 times compared to disc-based databases. Such massively powerful computing horsepower has more than a few or many data-obsessed executives eager to make the transition to SAP HANA in order to gain what they perceive is a competitive edge over industry rivals.

A primary point that differentiates SAP HANA from other databases is the use of in-memory blades to store information. This is one piece of the system which allows for the dramatically improved processing times that enhance analytical intelligence: by processing more information at a faster rate of speed, a more accurate picture can be created. It also allows for faster information retrieval. This has a wide-ranging application, from expediting business processes to allowing energy usage queries that let customers access an up-to-date picture of their energy usage habits to make smarter decisions. Crunching all of this data quickly allows ultimately for the creation of newer, and more effective, business models.

Despite the promise of SAP HANA, there is one sobering aspect of this technology to consider: cost. It's not practical to simply operate the database at a near full capacity, as the system becomes subject to the same performance bottlenecks as current enterprise resource planning (ERP) systems when available memory runs low. However, SAP HANA's in-memory blades are rather expensive, which makes it impractical to routinely add memory on a 'pay-as-you-grow' basis. This can quickly cause IT budgets to spiral out of control, growing at an unsustainable rate.

For this reason, keeping databases as lean as possible is a major priority for businesses pursuing an SAP HANA strategy. This is accomplished by utilizing an aggressive and proactive approach to data management and archiving. Traditionally, the word 'archiving' conjures images of data stored away in an offline database that is difficult, if not impossible, to access or have active visibility into. However, that simply is not the case anymore.

Dolphin, an SAP software partner, for example, uses an approach that moves large amounts of static data to a lower-cost, high performance nearline storage environment that complements the in-memory SAP HANA architecture. Nearline storage, or NLS, is an inexpensive, scalable option for storing large volumes of data which also allows for near real-time access, ensuring that visibility of this data is not limited.

NLS is successful when static data that has lower business value but is accessed occasionally is separated from frequently used, 'high-value' information. The result is a balance between performance speeds and storage costs. It stabilizes database growth, allowing for predictable Total Cost of Ownership, while protecting data for business needs such as analytics, business processes.

Early Adopter: Southern California Edison

To date, approximately 2,000 SAP HANA platforms have been deployed, in various stages, throughout the world. One regional utility which has opted to implement SAP HANA is Southern California Edison (SCE), based in Rosemead, California. SCE is the largest subsidiary of Edison International, and is one of the nation's largest electric utilities, serving nearly 14 million people in 180 cities across 50,000 square miles in Central, Coastal, and Southern California.

Ron Grabyan, Manager of Data Warehousing Services at SCE, notes that the electricity provider is utilizing SAP BW powered by SAP HANA for its Enterprise Data Warehouse and native SAP HANA for specific use-cases and analytical calculation energies. "In-memory computing intrigued SCE, as it appeared to provide the significant improvement of performance for reporting, analytics, and data loading we required," said Grabyan, who has managed SCE's business intelligence development effort on SAP BW since its inception in 2005.

Grabyan said the promise of faster reporting, faster data loading times, lower Total Cost of Ownership, reduced maintenance costs and decreased development costs all influenced SCE's decision to transition to SAP HANA. "Our data management strategy going into SAP HANA was to migrate the entire BW platform to BW HANA, producing capabilities on native SAP HANA for analytics that we could not achieve prior," Grabyan explained.

An important piece of the SAP HANA puzzle for SCE was to develop a strategy to keep database growth in check. According to Grabyan, SCE's Enterprise Data Warehouse was growing at 34 gigabytes per month prior to BW HANA. By utilizing SAP HANA, SCE was able to compress data by five times in its BW and up to 15 times on native SAP HANA. The next step was to utilize nearline storage. SCE worked with SAP to identify SAP-certified partners, and ultimately selected Dolphin, which architected a solution that included PBS Software's nearline infrastructure. The end result is database growth has been reduced to 17 gigabytes per month – a full 50 percent reduction in growth.

"The savings from adding nearline storage is directly proportional to the memory reduction on BW HANA," observed Grabyan. "We can still execute queries seamlessly against BW HANA, which retrieves data from both SAP HANA and NLS as appropriate. It's relatively easy to maintain and to keep BW HANA objects up-to-date in the NLS system."

Grabyan points out the benefit of SAP HANA and NLS is improved turnaround time for data retrieval and providing governance data to regulators. Additionally it delivered a lower total cost of ownership and faster project payback.

The Road to SAP HANA Starts Today

For IT teams considering the SAP HANA journey, there is a practical strategy to pursue that will ease the transition to the platform whether it is taking place months or years down the road. Even better – it will also improve existing SAP ERP performance.

To begin, evaluate current needs for streamlining infrastructure and accessing data. Identify key performance indicators (KPIs) for system performance as well as specific areas for cost reduction, management and avoidance. This will also allow CIOs to more fully understand the full promise of data environments.

Another important consideration when migrating to SAP HANA is a comprehensive database assessment or health check. Dolphin's HealthCheck, for example, is a proactive audit that will help safeguard against costly system down time and ensure that the in-memory infrastructure remains lean and stable by analyzing system performance, size and growth of production environments, and cost reduction/containment.

The resulting report will provide an overview of the health of the database on a monthly basis. What can businesses hope to achieve from this audit process? In this context, the HealthCheck for SAP archiving provides insight into realizing significant opportunities for SAP database improvement and a clearer path to SAP HANA.

Companies preparing for the transition to SAP HANA from their current SAP NetWeaver BW or ERP platforms will also benefit substantially from utilizing nearline storage. By developing a strategy for archiving static, less critical data using a NLS infrastructure today, organizations will experience improved performance, reduced Total Cost of Ownership, and a faster payback while also creating the most navigable road to SAP HANA.

What the Future Holds

Many utilities today are challenged in ways they'd never imagined just a few years ago. The amount of Big Data available for consumption and analysis is simply staggering. It's no longer the sole concern of the CIO, either. Senior leadership at all levels has increasingly come to understand the value offered by Big Data and are now starved for insights. Advancements in ERPs, such as the leap forward offered by SAP HANA, promise to deliver processes, analytics and new uses for data at a level never-before achievable. Early adopters of HANA, especially those who manage database growth to keep costs in check, will be the first to realize this competitive edge as they unlock new, wide ranging data applications that benefit both the business and the customer.

About the Author

Dr. Werner Hopf, CEO, is responsible for setting the company's strategic corporate direction and is the Archiving Principal at Dolphin. With more than 20 years of experience in the information technology industry, 16 focused in SAP, Dr. Hopf specializes in SAP Information Lifecycle Management initiatives including Data and Document archiving, SAP Archive Link Storage Solutions and Business Process solutions. His experience spans both large and mid-sized companies across all major SAP modules. Having worked on SAP projects across North America and Europe, he has extensive experience in global markets and is well known for his expertise. Dr. Hopf earned a Masters of Computer Science degree and a PhD in Business Administration from Regensburg University, Germany.

Advanced DMS and Microgrids: A Match Made in Heaven

By Jeff Meyers, P.E.

As long as there has been a commercial distribution grid, non-utility-owned distributed generators (DGs) have presented operating challenges. Relatively small point generation sources connected at low or medium voltage make grid operators worry about things like synchronization, system protection and safety. But for the past 100 years or so, DGs have been few and far between and consequently their impact has been limited. That is of course, until the smart grid era, when distributed energy resources (DERs) like solar and small wind generators combined with energy storage systems began to proliferate. Meanwhile, micro-turbine technology has improved rapidly, making super-efficient combustion combined heat and power (CHP) units economically attractive. All that DG/DER growth is a fact of life in the modern, diverse grid, but distribution system operators are still wary of the operating impact of a large number of widely dispersed point sources. Enter the microgrid, a concept that is gaining momentum in the utility community, both on the grid and customer sides.

Figure 1 – The Modern, Diverse Grid

Microgrids hold promise as a way to organize distributed generation into a beneficial supplemental power source for consumers and the grid, reducing the cost of peak power while enhancing grid reliability. Utilities need to achieve these benefits while simultaneously managing the distribution network efficiently, safely and reliably. That means that grid operators must overcome the hurdle of integrating microgrids within the traditional grid, and that requires advanced tools. One solution that has attracted the attention of leading utilities is the Advanced Distribution Management System (ADMS), a powerful combination of advanced analytics and real-time control. Implemented in the microgrid-enriched network, ADMS enables this advanced form of DG to deliver on its promise of enhanced reliability and reduced cost.

Microgrids: Think Globally, Grid Locally

A microgrid is a small-scale version of the centralized power grid. It generates and distributes electricity on a localized basis, usually at distribution (low or medium) voltage. Microgrids are designed to operate either in isolation from (as an island) or interconnected with the 'big' grid, often referred to as the area electric power system or AEPS to avoid confusion. They may be as small as a single residential or commercial load, or may be configured to provide power to a larger commercial property such as a shopping mall, college campus or military installation, or even an entire neighborhood. Most microgrids consist of one or more generators, matched to the load in an area that can be isolated from the AEPS. Figure 2 illustrates a fairly complex, but complete, microgrid.

This particular configuration is an entirely low voltage cell connected behind a single transformer to the AEPS through a medium voltage interconnection point. In the illustration several kinds of low voltage distributed generators are represented within the microgrid, although multiple units of a single type of generator would be more typical. Note that some renewable sources, such as photovoltaic solar and wind energy are depicted, along with an energy storage mechanism. As one of the key business drivers for implementing a microgrid is to improve reliability, microgrid configuration is a great means of coupling energy storage (like lithium-ion or flow batteries) with intermittent renewable sources.

A well-designed microgrid can enhance reliability, seamlessly interconnecting with and separating from the AEPS when it experiences an outage, allowing critical loads to be served continuously. Critical loads are connected on low voltage feeders with local generators, while other (non-critical) loads within the microgrid can be isolated and dropped as required during an outage. Typically, the sizing of the generators would, at a minimum, match the requirements of the critical loads within the microgrid.

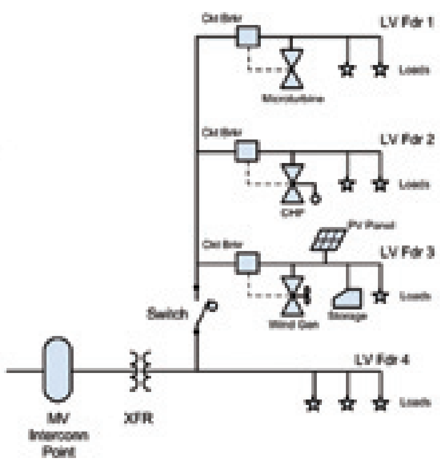


Figure 2 – Microgrid Configuration

Beyond emergency disruptions, microgrids also afford consumers the opportunity to disconnect from AEPS when the cost of power (for example, during system peak) exceeds the cost of local generation. Because microgrids deliver power in close proximity to its generation point, they avoid much of the overhead cost associated with transmitting and distributing energy, including the losses inherent in long distance energy transport. A grid cell with that capability benefits its owner and the utility alike, by making it possible to reduce the cost of peak power for both. The utility also may enjoy the opportunity to shave peak power without having to resort to the unpopular practice of curtailing other loads to do so.

Other, less common reasons for implementing microgrids include serving a remote or otherwise logistically difficult area, typically one that is dependent on a single, vulnerable grid connection.

As microgrids gain momentum, it seems clear that the industry believes they have the potential to enhance reliability and reduce cost. Yet, on the grid side, operating issues still remain, and will have to be overcome for microgrids to become mainstream.

First, there is the problem of system protection. When distributed generators provide power beyond the needs of the local loads, that power will flow back into the grid. But unlike the transmission grid that connects large, centralized power plants, the distribution system was not designed for bi-directional power flow. When a fault occurs in the medium or low voltage part of the grid, all protective gear assumes that power is flowing in a single direction, from a known source to all end points. That assumption greatly simplifies and reduces the cost of the distribution system's protective scheme, but the existence of distributed generation can nullify the principles of design, and cause the scheme to fail when the grid needs it most – under a fault. Even with reverse power relays in place to isolate the microgrid for a medium voltage fault, the coordination of the distribution system scheme can be violated.

System stability is another central concern. Although one core concept of microgrids is to match local generation to local loads, system operators may be justified in worrying about large amounts of both generation and load cycling into and out of the grid. Managing real and reactive power and frequency of interconnected generators can, at times, be challenging. Voltage set points and reactive power requirements are not static but vary with the changing conditions of the system. Intermittency due to the nature of renewable resources, or to potential problems on the consumer side of the switch could easily result in major swings in demand or capacity for a fairly limited area of the system. It doesn't take much of an imagination to conceive of a scenario where the distribution grid might not be able to withstand a shift of significant size without impact to other customers in the immediate network vicinity.

Beyond the issues of system protection and stability, a lack of visibility into and control of significant microgrid presence could lead to inefficiencies in the system. There are times when it makes sense to monitor and control the grid in a holistic, centralized fashion. A bigger picture view is helpful to optimize voltage and VARs, for example, and to dynamically reconfigure the network for various operating constraints. In short, planning for and operating the grid in the presence of distributed generation, even when it is packaged in microgrid configuration, is not trivial. And that's where a better network management tool like an Advanced Distribution Management System can help to ensure safe and reliable operation.

A Smarter Grid Calls for Smarter Distribution Management Systems

Microgrids can add to the reliability and efficiency of the grid, but they also add complexity. A tool like ADMS provides the platform for modeling, monitoring and managing the microgrid-enhanced power system. But before we look at how ADMS might help, a step back to describe the tool might be helpful. In the often-hyped environment of the smart grid, it isn't unusual for a product or system to be called 'advanced'. But in the world of operational control of the grid, ADMS has some very specific characteristics:

- **Convergence of SCADA, DMS, and OMS functionality**: In addition to real-time network analysis, the ADMS allows the user to operate all SCADA monitoring and control functions, as well as presenting complete OMS functionality for managing outages and dispatching crews. The right user experience is critical; the ADMS presents an integrated flow of information in a single, straightforward user experience, simplifying the operations and analysis of the distribution grid for the operator.
- **Scale of data management and analysis**: To manage the smarter grid, ADMS must account for hundreds of thousands, or even millions of real-time data points. And accounting for a variety of new devices and end point types, the ADMS must be able to adapt as new kinds of distribution and customer devices come on line.
- **Scope of feature function**: Starting with closed loop control, or the ability to analyze, execute commands, and then re-analyze the network to determine impact, the ADMS must be able to provide functions that drive critical business value for the smarter grid. Optimizing volts/VARs to increase efficiency and reduce peak load, enabling distributed generation and other forms of DERs, supporting demand response analysis and execution, and automating the distribution switching process to enable a faster response time, are a few of the many important groups of functions that support smart grid processes and value.

These capabilities make ADMS the key tool for getting a handle on the increasingly complex distribution grid, especially one containing one or more microgrids. The functions required are many, but the shortlist below provides a good overview of the features that ADMS brings to the microgrid integration problem:

- Load Forecasting – Detailed load profiling and weather integration
- Renewable Forecasting – Using weather integration to forecast microgrid renewable generation
- Network Planning – Model voltage changes, flicker, fault currents, and contribution from microgrids
- Network Reconfiguration – Optimize network to minimize losses
- Relay Protection – Adaptive control and recloser operation
- Fault Calculation – Model DG effect on fault current
- Volt/VAR Control – Manage load taps, capacitors, voltage regulators with closed loop control
- FLISR – Closed loop control (automated) switching
- Harmonic Indices – Report harmonic distortion in voltage and current levels
- DER Operation – managing DG and energy storage systems for balancing load
- Load Shedding – Sustain power system stability during disturbances
- Isolated Operation – Islanding support with load balancing and frequency, and voltage stability

A modern ADMS has the power to analyze and manage large, complex networks quickly, which enables system operators to evaluate scenarios both with and without microgrids to assess their impact. And using real-time state estimation and load flow calculations, the ADMS can provide the key operating tool to help manage the grid during steady state and emergency operations, while allowing microgrids to interoperate and contribute to grid reliability and efficiency.

ADMS and Microgrids Working Together for a Smarter Grid

Microgrids are likely to become standard in the modern, diverse grid and they can provide big benefits to both customer and utilities. But they bring with them a set of challenges that will have to be met. ADMS provides the means to model, monitor, and manage the microgrid-enhanced grid, allowing both the distribution system and interconnected microgrids to perform at their best.

About the author

Jeff Meyers, P.E., smart grid strategy and development, Smart Infrastructure, came to Schneider Electric as the former president of Telvent Miner & Miner. Leveraging his experience in utility transmission, substation and distribution design, Meyers works with development teams and utility users of Schneider Electric technology, helping them to understand the Smart Grid and how the use of integrated technology can bring energy efficiencies to the industry.

THE BIGGER PICTURE

BY BERNADETTE CORPUZ

Ontario Renewables: Big no Longer Fit; New Game to be played

The Ontario Power Authority ("OPA") launched draft rules for the third series in Ontario's Feed-in Tariff Program ("FIT 3.0") on September 4, 2013. While final rules and contract documentation has not yet been issued at the time of writing, a direction issued by the Province's Minister of Energy earlier in June clearly indicated that large renewable projects (greater than 500 kW) would no longer be eligible to participate in FIT. Instead, large renewables would become subject to a new competitive procurement process.

Development of a New Renewable Energy Competitive Procurement Process

During the summer of 2013, the OPA engaged in consultations for the development of a renewable energy competitive procurement process for large renewable projects. The OPA's resulting interim recommendations are set out in its report entitled 'Development of a New Large Renewable Procurement Process – Initial Engagement Feedback and Interim Recommendations' (the "Report"), which was submitted to the Minister of Energy on August 30, 2013.

The Report does take into account feedback received during the OPA's other major engagement activities:

- The work between the OPA and Independent Electricity System Operator ("IESO") to improve regional electricity planning and siting of large energy facilities;
- The Long-Term Energy Plan (LTEP) consultations.

Reactions So Far – General Stakeholders

The OPA hosted a webinar for the general public and stakeholders on August 7, 2013. Over 300 people participated and more than 200 questions were submitted. Key comments provided include the following:

- A request for proposal process would limit participation to large proponents only. Community groups would face challenges in competing;
- More participants felt separate procurements for different technology types and sizes would be warranted, as compared to a bundling of all technologies into a price competition;
- Some felt the prioritization of Aboriginal groups, cooperatives or public sector partnership projects should incorporated (along with price adders or similar incentives) similarly to the FIT Program;
- Regional electricity planning processes should drive procurement requirements;
- Communities and municipalities should be engaged during the siting of projects;
- Non-price factors should be included such as community involvement or social benefit;
- Transparency in the connection testing process remains important.

Municipalities

The municipal webinar session highlighted the continuing importance of the following issues:

- Improved alignment between siting project guidelines and local municipal guidelines and zoning;
- Improved alignment between project approvals and sit plan approvals;
- Challenges in supporting a project before detailed environmental studies, site plan drawings and community engagement are complete.

In addition, in-person meetings were conducted and written submissions invited. Similar themes as those described above emerged:

- Separate procurements based on technology (e.g., solar should not compete against wind);
- Separate procurements based on size (e.g., < 10 MW vs. > 10 MW);
- Expand FIT to include projects < 5 MW;
- Municipal involvement in decision making (some lobbying no veto);
- Land use and siting criteria should be handled by municipalities;
- Public meetings needed during proposal phase to inform communities of proposed projects;
- Strike a balance between impact on ratepayer (and competitiveness of Province) and promotion of ancillary benefits (e.g., job creation, environmental improvements);
- Small, community based groups, Aboriginal communities and co-op involvement should be prioritized;
- Developer experience and track record should receive higher weighting relative to other factors;
- Higher security deposits should be required;
- Financial acumen should be assessed;
- Maintain capacity set asides, price adders, FIT pricing, FIT prioritization system;
- Incentives should be included to encourage local sourcing
- An RFP process is appropriate (without EOI); an RFQ/RFP is more appropriate than EOI/RFP
- Better inter- and intra-government as well as agency coordination required around project approvals;
- Regular procurement 'windows' required to provide industry stability;
- Align procurements with regional energy planning and LTEP;
- Waive the 120% solar DC/AC limit;
- Concerns about government-owned OPG participation in procurement and unfair advantage over independent power producers;
- Include energy storage technologies in the procurement process.

Link to Electricity Regional Planning Initiative

The OPA and the IESO released their report on regional electricity planning entitled '*Engaging Local Communities in Ontario's Electricity Planning Continuum*' in August 2013 (the "Planning Report"). The Planning Report was prepared in response to the Minister of Energy requesting that the OPA and IESO work together to develop recommendations for a new integrated regional energy planning process that would focus on improving how large energy infrastructure projects are sited in Ontario. It will be critical for the recommendations in the Planning Report to be least complementary, but perhaps integral, to some of the key factors identified by stakeholders as critical in the procurement process for large renewable projects.

The key areas of focus of the Planning Report include:

- Regional electricity planning;
- Enhancing engagement with municipalities, energy stakeholders and First Nations, Métis;
- Ensuring these groups are engaged in processes related to the siting of large electricity generation and infrastructure projects.

The recommendations of the Report are designed to support the following overall objectives for improving electricity planning:

- Bringing communities to the table;
- Linking local and provincial planning;
- Reinforcing the planning/siting continuum;
- Enhancing electricity awareness and improving access to information.

The following three core recommendations represent a rough consensus of the stakeholder community:

1. Strengthen processes for early and sustained engagement with local governments and the public. The IESO and the OPA will build on existing processes to improve stakeholder engagement.
2. Provide local governments and communities with greater voice and responsibility in planning and siting. The OPA, IESO, Ontario Energy Board, and the Ministry of Energy should explore mechanisms to provide greater flexibility to municipalities and First Nations to meet local needs. These mechanisms should also explore cost responsibility and reliability of service.
3. Support inter-ministerial coordination. The province should develop an 'inter-ministerial action team' of senior officials from the Ministries of Energy, Transportation, Infrastructure, Health and Long Term Care, Municipal Affairs and Housing, Environment, and Aboriginal Affairs to coordinate policy development and clarify decision making.

Recommendations

The OPA has made a number of interim recommendations to the Minister of Energy for two distinct time frames: (a) the period leading to the launch of the procurement, and (b) the duration of the procurement.

Action Pre-Launch

- Fall 2013, continue the municipal, First Nation and Métis, and stakeholder consultations
- Include in the Long Term Energy Plan recommendations regarding quantity and timing of new resources to be procured
- Generation procurement should follow the provincial and/or regional electricity system need
- Conduct multiple successive rounds of procurements, organized by technology, size or area of need – larger projects (greater than 10 MW) would be focused on experienced developers. Mid-size (500 kW to 10 MW) could encourage partnerships (Aboriginal, municipal, community).
- Procurement need, goals and expectations should be clearly articulated
- Municipal electricity generation preferences should be considered
- Local outreach should be conducted prior to procurement commencement

Components of Procurement Exercise

- Continue procuring through the Request-for-Proposal (“RFP”) model
- Project bid price should remain a key RFP evaluation factor
- Proponent experience and financial capability should be considered
- Continue to encourage community, Aboriginal, municipal and public sector entity participation through procurement incentive mechanisms
- Site due diligence evidence should be required
- Interconnection information and cost estimates provided earlier in the process
- Provide greater municipal control over land use and siting
- Require community engagement sessions and council deputations during the RFP phase
- Minimum community acceptance criteria should be considered
- Further clarity on OPG participation is needed
- Conduct further research on technology bundling

The Report does not include recommendations for identifying the quantity or types of renewable generation facilities for which to issue a procurement call. This is expected to be addressed by the LTEP once completed.

What’s next?

Clearly, Ontario is still highly engaged in the renewable file. FIT 3.0 is expected to be finalized in October with the first application window opened shortly thereafter. Current pricing has been confirmed with the release of an updated price schedule for the FIT and microFIT programs and for FIT price adders for Aboriginal Participation Projects, Community Participation Projects and Municipal or Public Sector Entity Participation Projects. The OPA’s revised price schedule and FIT Price Adders are as follows:

FIT/microFIT Price Schedule – August 26, 2013

Renewable Fuel	Project Size Tranche*	Price (¢/kWh)	Escalation Percentage**
Renewable Fuel	≤ 10 kW	39.6	0%
Solar (PV) (Rooftop)	> 10 ≤ 100 kW	34.5	0%
	> 100 kW	32.9	0%
Solar (PV) (Non-Rooftop)	>10 kW	28.8	0%
On-Shore Wind	All sizes	11.5	20%
Waterpower	All sizes	14.8	20%
Renewable Biomass	All sizes	15.6	50%
On-Farm Biogas	≤ 100 kW	26.5	50%
	> 100 kW ≤ 250 kW	21.0	50%
Biogas	All sizes	16.4	50%
Landfill gas	All sizes	7.7	50%

* The FIT program is available to Small FIT projects; that is, projects generally ≤ 500 kW.

** Escalation Percentage based on the Consumer Price Index will be applied to eligible Renewable Fuels as calculated in the FIT Contract. The Base Date is January 1 of the year in which the Project achieves commercial operation, unless the Project achieves commercial operation in October, November, or December, in which case the Base Date is January 1 of the following year.

FIT Price Adders

	Aboriginal Participation Project	Community Participation Project	Municipal or Public Sector Entity Participation Project	
Participation Level (Equity)	>50%	>15% ≤ >50%	>15% ≤ > 50%	>15% ≤ 50%
		50%	50%	
Price Adder (¢/kWh)	1.5	0.75 1.0	0.5 1.0	0.5

Note: The above table applies to all FIT Project sizes and all technologies except Solar (PV) (Rooftop).

Large renewable projects will have to wait for the new competitive procurement process to be determined. On this front, the OPA will be undertaking additional engagement activities on the interim recommendations in the fall to further inform the development of the new competitive procurement process and will also incorporate the feedback that is being received by the Ministry as part of the ongoing LTEP review.

ABOUT THE AUTHOR

Bernadette Corpuz is a Senior Associate in the Electricity Markets Group of the law firm Borden Ladner Gervais LLP (BLG). As a member of the Electricity Markets Group, Bernadette advises a wide range of energy market participants, including distributors, transmitters, generators, and commercial users with respect to a variety of commercial and corporate transactions related matters, including mergers and acquisitions, financing and energy markets. Bernadette can be reached at **bcorpuz@blg.com** or 416-367-6747.

By Doug Westlund, P.Eng.

SECURITY SESSIONS

Executive Summary

Cyber-attacks against critical infrastructure sectors in general and the energy sector in particular have escalated at an alarming rate in recent years. Within the energy sector, municipally and cooperatively owned utilities are among the most vulnerable targets because they have the same systems and front-page appeal as large investor owned utilities (IOUs) but frequently lack the financial and human capital needed to implement large and lengthy enterprise level security projects. By necessity, public power and cooperative utilities have had to find a different approach because doing nothing was not a viable option – not only for their own security but also for the larger grid to which they are connected. By focusing on their strengths including a more nimble decision process and interconnected regional networks some municipally and cooperatively owned utilities are implementing innovative solutions that could have the larger IOUs rethinking their approach.

This article reinforces the cyber threat confronting the energy industry and focuses on topics including: current trends, category vulnerabilities and why the solution for cooperatives and municipal utilities needs to differ from those available to large IOUs. Finally the article spotlights a cyber-security project currently underway at a cooperatively owned G&T where some of these initiatives are being implemented. For security reasons the name of the utility is not disclosed.

A large and growing problem

The Industrial Control Systems Cyber Emergency Response Team is the department of Homeland Security division that responds to cyber-attacks against critical infrastructure installations. In 2009 they responded to nine reported incidents.[1] Since then, they have become much busier.

Last year ICS-CERT responded to 198 cyber-attacks against critical infrastructure targets including electric and water utilities, pipelines and nuclear facilities.[2] These attacks represented an increase of more than 50 percent versus the previous year. In 2013 that figure is on track to double. In the first half of the fiscal year (October 2012 to May 2013), ICS-CERT responded to more than 200 incidents, exceeding the 12-month total from the previous year.[3] A disproportionate number of these incidents continued to originate from the energy sector.

In the 2012 report, 41 percent of the reported incidents targeted the energy sector. By the mid-year 2013 report the energy sector accounted for 53 percent of the incidents. While the report does not explicitly state why the majority of all incidents targeted the energy sector, security experts frequently cite size and response hurdles as contributing factors.

The attack surface of the grid is simultaneously becoming larger and more vulnerable. The grid's vast network of interconnected generation, transmission and distribution systems creates an attack surface that ranks second only to the internet in scope. As the grid continues to grow through increased interconnectivity and interoperability it is also becoming much less secure. Remote assets like sub-stations, previously islanded from enterprise information systems, are being brought into SCADA environments without adequately hardening systems against the vulnerabilities these new additions create. Despite the increased risk, defensive initiatives by utilities have been hampered by cultural, organizational and resource issues.

RESPONSE CHALLENGES

A Culture of Compliance

Utilities are both legally and culturally driven by regulatory requirements and standards. On the plus side of the equation, this culture of compliance promotes uniform policies that create an industry-wide level of quality and reliability. On the negative side it can discourage independent initiatives that become necessary when the problems are progressing faster than the policies. This latter situation is confronting utilities who are struggling to span the divide between compliance and real security.

Part of the problem is with the policy makers. A report issued by the Government Accountability Office (GAO) stated that: *Aspects of the current regulatory environment make it difficult to ensure the cyber security of smart grid systems.*[4] The report specifically noted the concern about the ability of regulatory bodies to respond to evolving cyber security threats. This concern has been echoed by elected officials, security agencies and regulatory bodies themselves.

Former FERC chairman Wellinghoff frequently addressed this topic including the following statement which points to the lack of an actionable command and control structure.

> "My intent is to simply have somebody be put in charge," Wellinghoff said in response to a question from The Hill at the Platts Energy Podium in Washington, D.C. "And the person who's put in charge has the authority to tell those entities that are responsible for the infrastructure of the immediate threat and vulnerability, and to order them to do something if necessary to mitigate that threat or vulnerability."
>
> "That's my really, bottom-line message. It doesn't have to be FERC."[5]

While it is clear that the regulatory structure needs to improve, utilities also bear some of the responsibility themselves for the slow pace of change. The same GAO report referenced above makes it clear that both utilities and oversight agencies need to progress beyond mere compliance.

> Utilities are focusing on regulatory compliance instead of comprehensive security. The existing federal and state regulatory environment creates a culture within the utility industry of focusing on compliance with cyber security requirements, instead of a culture focused on achieving comprehensive and effective cyber security. Specifically, experts told us that utilities focus on achieving minimum regulatory requirements rather than designing a comprehensive approach to system security. In addition, one expert stated that security requirements are inherently incomplete, and having a culture that views the security problem as being solved once those requirements are met will leave an organization vulnerable to cyber-attack. Consequently, without a comprehensive approach to security, utilities leave themselves open to unnecessary risk.

But even utilities that are willing to step beyond mere compliance measures still have to wrestle with implementation issues including organizational accountability gaps that have significant cyber-security ramifications.

The IT / OT Gap

Historically, the responsibilities of utility information technology (IT) departments were confined to the servers and computer systems that housed customer data, billing information and other digitally stored data. At the same time operational groups concerned themselves with the performance, maintenance and reliability of assets. For the most part, the virtual concerns of the IT group did not intersect with Operations' concerns for physical assets. Today, the operation and management of physical assets is increasingly being managed through virtual systems and as a result departmental lines have blurred. IT groups struggle with the introduction of disparate and often unsecured assets into the information technology environment. Operational groups find themselves in need of support from IT groups that do not operate on the 24x7x365 schedule that operational staffs do. This Informational Technology / Operational Technology (OT) gap has not escaped the notice of hackers.

At Black Hat USA 2013, a hacker conference in Las Vegas, one of the most popular sessions highlighted a hacker's ability to gain control over utility systems through remotely deployed assets. The following is an excerpt from the description of the session from the conference's website:[6]

> In this presentation, we review the most commonly implemented key distribution schemes, their weaknesses, and how vendors can more effectively align their designs with key distribution solutions. We also demonstrate some attacks that exploit key distribution vulnerabilities, which we recently discovered in every wireless device developed over the past few years by three leading industrial wireless automation solution providers. These devices are widely used by many energy, oil, water, nuclear, natural gas, and refined petroleum companies.
>
> An untrusted user or group within a 40-mile range could read from and inject data into these devices using radio frequency (RF) transceivers. A remotely and wirelessly exploitable memory corruption bug could disable all the sensor nodes and forever shut down an entire facility. When sensors and transmitters are attacked, remote sensor measurements on which critical decisions are made can be modified. This can lead to unexpected, harmful, and dangerous consequences.

Security issues associated with this increased interconnectivity between IT and operations are starting to get attention from the energy industry and cyber-security vendors alike.

In a recent Public Power Daily article[7] APPA President and CEO Mark Crisson advised member utilities to determine if their Operations Departments shared any systems with enterprise or information technology departments to be sure that "…one doesn't provide a backdoor to the other."

Large, enterprise IT consultancies are also aware of the IT/OT gap and have added terms like 'Operational Technology' and 'IT / OT Convergence' to their utility targeted offerings.

Resource Limitations

While IT/OT offerings from large, enterprise IT consultancies is a step in the right direction, it is not a panacea. The high cost puts these solutions beyond the reach of all but the largest IOUs.

Large consultative cyber-security projects can last a year or longer with costs that can run into seven digits for fees alone. Based on industry standards, these types of enterprise level cyber-security engagements are estimated at 15 percent of cost of the total IT system. This puts them out of the reach of most municipal and co-op utilities.

A Surprising Trend

Based on the cultural, organizational and especially resources challenges articulated thus far it would be easy to assume that larger IOUs are more secure than municipally and cooperatively owned utilities.

Surprisingly this may not be the case.

While municipally and cooperatively owned utilities may not have the resources of larger IOUs they make up for it by being less resistant to new solutions and a more nimble decision making process. This observation comes from first-hand experience dealing with all three types of utilities and is reinforced by data from a recent congressional report.[8]

In January 2013 Representatives Edward J. Markey and Henry A. Waxman requested information from utilities including 150 IOUs, municipally-owned utilities, rural electric cooperatives and federal entities. In addition to revealing that some of the utilities were under 'a constant state of attack,' the report concluded that: *Most utilities only comply with mandatory cyber-security standards, and have not implemented voluntary NERC recommendations*.

For example 91 percent of IOUs, 83 percent of municipally- or cooperatively-owned utilities reported that they were compliant with mandatory measures related to the Stuxnet virus. By contrast, 21 percent of IOUs and 44 percent of municipally- or cooperatively-owned utilities reported compliance with the voluntary measures. Clearly, the non-mandatory response by all utility categories could have been better, but it was interesting to note that despite a resource disadvantage, the voluntary security response by municipally and cooperatively owned utilities was much stronger.

Municipally and cooperatively owned utilities may be more willing to adopt non-mandatory security measures because they are more closely tied into the fabric of the communities they serve. They take great pride in service delivery; many of their CEOs / General Managers will say: "my neighbor is my owner, and my aim is to provide the best possible service." It would be stretching the facts to definitively state that these results mean that municipally and cooperatively owned utilities are more secure than IOUs, even within this limited data set. It does, however, suggest that the municipally and cooperatively owned utilities are more willing to go beyond mere compliance and seek outside resources to help them achieve real security.

One example of a proactive approach to cyber-security is the work N-Dimension Solutions, a cyber-security firm specializing in critical infrastructure assets is doing with a large cooperatively owned Generation and Transmission (G&T) utility in the southwestern part of the United States. The utility is not identified for security reasons, but N-Dimension has a long track record of working with both municipally and cooperatively owned utilities and related associations.

"The American Public Power Association is working hard to educate public power utilities on the cyber security risks to their operations" said Jeff Haas, Vice President, Membership and IT, American Public Power Association. "N-Dimension has assisted APPA develop tools and deliver information to improve the cyber security posture of public power systems".

A cooperatively owned utility case study

The utility in this case study is a tax exempt, consumer-owned public utility that provides low cost, reliable electric service for its rural distribution cooperative members. Its member systems serve retail consumers located across a large geographical footprint.

The members are interconnected through a private Wide Area Network (WAN) using AT&T Multi-Protocol Label System (MPLS) routers. This network is private in the sense that data on the network is isolated from non-network members. The data itself, however, was not encrypted.

Nothing about the network was out of compliance with NERC CIP standards including the fact that the data was not encrypted. Nevertheless, when the G&T upgraded its AMI metering system, they also took the opportunity to improve the level of security on their network.

For several years, N-Dimension Solutions had been working on cyber-security solutions specifically designed for municipally and cooperatively owned utilities. In contrast to the costly, all-consuming engagements of large technology consulting practices, the more specialized company focused on providing a product based solution that was modular, extensible, and most importantly affordable.

Through a close working relationship with both the APPA and the NRECA, N-Dimension had already contributed to the development of a significant number of the cyber-security guidelines, educational and training materials that each service organization provides to its respective members.

"Cyber-security for utilities requires a more complex solution than just securing IT systems especially for our Generation & Transmission cooperatively owned facilities," said Craig Miller, CTO NRECA. "N-Dimension provides cyber security offers that are uniquely suited to protect the operational assets of G&Ts and their co-op members"

After reviewing the utility's systems, N-Dimension identified a number of potential attack vectors including:

- SCADA and AMI data collected from member SCADA systems over a private IP-based WAN leased from a Telco
- Security of this WAN requires 100% security of each and every router and link in the network, which includes a diversity of devices both owned by the telco and leased from local providers
- Physical access to any of the routers or links in the WAN
- Varying security of member SCADA systems on the WAN, including direct connections of those systems to member corporate networks and the public Internet

A larger concern than the specific threat vectors was the fact that an attack on any individual point of access opened the entire system to a cyber-attack. Based on this vulnerability simple objectives were established.

- Protect G&T systems from compromised member systems
- Protect non-compromised members from a compromised member

The solution to meet these objectives required four key capabilities:

1. Data encryption
2. Firewalls
3. Intrusion detection
4. Dynamic routing

The first three capabilities were already incorporated in N-Dimension's *n-platform*,™ a comprehensive cyber security unified threat management (UTM) software platform, designed specifically for protecting critical infrastructure that can be deployed across entire operational networks. The fourth capability was developed specifically to address this utilities configuration.

The solution uses point-to-point SSL VPNs to encrypt traffic across the private WAN between cooperative member SCADA systems and the G&T SCADA system. Encrypting traffic across the WAN ensures that the security of this traffic cannot be compromised by an attack against the Telco network. Traffic between member and G&T SCADA systems typically traverses 10 to 20 routers, and encrypting the traffic removes all links and all but the two endpoint routers as potential points of attack.

In addition to data encryption firewall rules were established to restrict the types of traffic allowed to traverse the SSL VPNs to specific protocols. Unlike a typical corporate network, the number of protocols that need to be allowed across this network of VPNs is very small. The allowed protocols are essentially just ICCP, SCADA synchronization, and AMI. Restricting the types of traffic allowed across the network significantly narrows the types of attacks available to an adversary to only those that exploit weaknesses in the allowed protocols. Previously, any type of attack would have been conveyed by the WAN from a compromised member system to the G&T network. NetBIOS and other undesirable traffic originating from member systems had previously been found on the G&T network, and are now blocked by these firewalls.

To guard against attacks that bypass the above protections, Intrusion Detection Systems (IDS) were implemented at each of the cooperative members and at the G&T to monitor traffic received from the VPNs and detect potential attacks and attack indicators. Tuning IDS systems on corporate networks is recognized as a difficult problem, but since the firewalls severely restrict the types of traffic that can be transported across the VPNs, tuning these IDS sensors is significantly simpler. The IDS alerts from the individual sensors are aggregated into an Event and Log maintained in the n-Central monitoring system run by the G&T, to provide network-wide awareness of threats.

Due to the broad geographical nature of the G&T and its members outages of individual communications links across the WAN are common. With the above technologies in place, using the public Internet connections as a backup communications resource was a natural extension. The solution uses SSL VPNs across the Internet to provide backup channels, and dynamic routing to automatically switch from the SSL links across the private WAN to SSL links across the Internet when there are connectivity issues with the WAN. Previously the G&T suffered approximately one SCADA communications outage per month, but with backup Internet communications, outages of SCADA data have all but disappeared. Outages now occur only when a member's Internet is provided by the same Telco that provides the WAN, or shares the same physical infrastructure.

All of these measures were implemented in close cooperation with the G&T's IT and Operational departments. The latter consideration was especially important because of the mission critical nature of the operational systems.

Moreover the project was more product focused than consulting based which fit the financial and human resource parameters of the cooperatively owned utility. Industry standard costs for cyber-security projects range from 15 to 20 percent of the facilities overall IT system cost. This project was closer to the five percent range.

It bears repeating that these measures were not required to comply with mandatory cyber security standards. They were motivated by the G&Ts recognition of the escalating threat of cyber-attacks and a genuine desire to ensure reliability, revenue assurance and risk mitigation for its member/owners. Moreover, the solution implemented was tailored to the specific needs of the G&T enterprise and operational systems. In our experience this bias toward effective action is characteristic of both municipally and cooperatively owned utilities who just might be leading the way into a more secure future for the smart grid.

ABOUT THE AUTHOR

Doug Westlund is an expert on the role of Operational Technology in the development of defense-in-depth cyber protection for critical infrastructure assets and is a regular speaker and presenter of cyber security topics in the energy sector at industry conferences across North America.

He co-founded N-Dimension Solutions in 2002 because cyber security solutions designed to protect enterprise systems did not have the Operational Technology rigor to protect critical operational assets from sabotage. Since then, N-Dimension has grown into a leading cyber security solutions provider for the critical infrastructure segments. As CEO, Doug is primarily focused on developing and implementing N-Dimension's strategic plan and business development activities such as developing N-Dimension's eco-system of strategic partners.

Prior to N-Dimension, Doug was a SCADA Engineer with Valmet Automation, a Business Development Manager with Motorola Information Systems, and a Vice President with AT&T Canada. Doug holds an Engineering degree in process control, an MBA, and is a licensed Professional Engineer.

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Guest Editorial 1

Smart Metering - the Customer Experience.

By Christine Easterfield

At the heart of every utility is the customer. Not the regulator, not the government, not even necessarily the shareholder – for without a contented customer, shareholder value is hard to sustain. And yet with so much change on the agenda at most utility companies it is easy to lose sight of the impact on the customer.

We all know that it is easier to keep a customer than to acquire a new one – this holds even for utilities, where to some extent infrastructure hampers real customer choice. But with governments and regulators promoting open competition between utility suppliers, providing a satisfying customer experience has to be high on the agenda or customers will be exercising their rights to take supply from elsewhere.

Smart grid developments have been much discussed in the last three to five years but how many of those developments are actually improving life for the customer? Let's leave aside the smart grid activities that are literally smartening the grid itself and largely benefit the utility – tools like next generation SCADA systems for optimised network management and smart reclosers that reduce maintenance call outs – and focus on where most utilities have dipped their toes in the smart grid story – metering.

Best use of resources

Florida Power & Light (FP&L) announced completion of their Energy Smart Florida initiative to modernize the grid and install 4.5 million smart meters across its service territory. An online portal enables customers to track their usage hour by hour to support changes in behaviour that saves money. FP&L themselves gain by having greater control of the grid and can deliver greater service reliability and improve outage management. Clear benefits to the customer, even if a little indirect.

However, FP&L do provide direct customer testimonials on their website to demonstrate how their customers are engaged with and benefitting from smart grid initiatives. Quoting the experience of ordinary citizens brings the benefit into sharper focus. Quotes like:

- "We've been able to be more proactive on our energy usage"
- "Energy efficiency not only saves me money, it's also good for the environment"
- "In today's economy, every dollar is important"

These cover a range of motivations and let other customers relate to the potential impact of a smart meter on their own circumstances.

Faster outage restoration

San Diego Gas & Electric (SDG&E) has 1.4 million smart meters installed in domestic and commercial properties. These work in cooperation with wireless sensors installed across the network. The sensors automatically detect outages and other problems on the electric grid and fault detectors send alarms if a problem occurs anywhere along the power lines. Operations staff can quickly send crews to that location based on the automatic wireless signals sent by these devices. This enables the utility to respond to power outages and restore electricity to customers faster than ever before. Again clear customer benefits, but the benefit to the utility is perhaps greater.

Erin Collier, communications manager at SDG&E said, "We are committed to providing user-friendly ways to help customers take control of their energy use. Using the newly installed meters as a base, we are developing programmes that create a two-way relationship with the customer to provide them with personalised information about energy use. Connecting to Home Area Network (HAN) devices means customers can see real-time energy use of individual appliances and electronics. SDG&E was also one of the first utilities to implement the Green Button initiative, giving our customers access to a growing range of tools to help them prove their energy efficiency."

SDG&E Smart Meter (Photo by SDG&E)

The 'Green Button' initiative in the U.S. is supported by central government and makes energy use data available in a common format. At SDG&E customers can download up to 13 months of their personal electricity data, which can then be analysed to help make choices about when and how they run appliances. Customers can also view their day to day account, encouraging households and businesses to monitor temperature gauges or run appliances on eco programmes, reducing peak demand for the utility and saving money for the customer.

Smart Metering - the Customer Experience.

SDG&E Home Area Network (HAN) Energy Aware Device

Comparative trial

In the UK, a three year trial compared different approaches to improving energy efficiency – including using smart meters. This study found success increased when customers actively engaged with improved data provided by smart meters and this is borne out by live rollouts. At the simplest level, no longer being disturbed by meter readers calling to the home and the assurance that utility bills would no longer have to be estimated is benefit enough. But real savings start to be seen when feedback on consumption is readily available, in short – easy to understand reports. To be actionable, feedback must be reliable and timely – which depends on the back office IT systems the utility chooses.

The UK government's Department for Energy and Climate Change (DECC) is driving many smart grid initiates, and recognises the need to engage with energy consumers. Supporting this, the department is restructuring to introduce a new directorate focused on ensuring consumers and households are considered on an equal footing with international policy on energy development and climate change, and bringing new generation capacity on stream. In a research exercise sponsored by DECC, a group of volunteers from the early implementation programmes were monitored to see if and how the smart meters impacted their day to day lives. Care was taken that the volunteers covered a range of household types, including consumers considered to be vulnerable – for example the elderly, those with physical or mental health issues, low income households and so on. Volunteers had a smart meter installed with an IHD – In-Home Display – unit so they had visibility of the impact of the smart meter. The study recorded how the volunteers reacted to the programme and if it encouraged them to change their behaviour regarding energy use. Not surprisingly there were a range of responses but the greater the visibility of energy use – for example keeping the IHD switched on and in a place visible to members of the household – the greater the change in behaviour. This underlines the need to provide usable feedback to the consumer, as well as education on the use of supporting tools.

Across Europe there is as much variation in the level of adoption by different countries as there is between states in the USA. Italy was one of the first countries worldwide to roll out smart meters. France and the UK are actively engaged in their implementation programmes. These are largely driven – or certainly encouraged – by central policies of the European Union that promote energy efficiency and backed by national governments that are both keen to enhance their green credentials and to reduce reliance on energy imports.

In France, smart meters will be rolled out to approximately 35 million subscribers starting with pilot projects handling 300,000 meters in the Lyon and Tours areas. This ensures both urban and rural networks are trialled and the experience of the trials will, it is hoped, lead to a smooth introduction country-wide. Consumers will benefit from remote meter reading, automatic fault detection and repair, and two-way meters supporting local and micro generation. By contrast, in Germany the installation of smart meters has stalled in mid-2013 following an analyst report that determined the cost of installing the meters would outweigh the benefits to individual consumers. While this is being investigated, there will be a considerable slowdown in the rollout programme in a country that previously championed smart meters.

The customer is at the heart

While ploughing resources into smart grid technologies, utilities must remember who is ultimately footing the bill. The customer has to be engaged and their concerns handled sensitively. Several groups, notably in the U.S., with pockets in the UK, Australia, and elsewhere, insist that smart meters are a health hazard. In response many American utilities offer 'opt-out' clauses for consumers to retain analogue meters. These utilities will have to keep records of where analogue meters remain and where smart meters are installed but are not active, and cope with maintaining provision for manual meter reading and alternative billing systems. An additional expense, maybe, but one that is necessary to keep the customer on side.

Smart metering was and is supposed to provide the customer with greater choice including the ability to monitor energy use remotely and to choose how to manage their consumption according to the attractiveness of the tariff. Improving the customer experience will encourage buy-in to the investment in new technologies across the network and soften the impact of the inevitable disruptions that come with that – from service disruption to simply more road works. Remember, a happy customer pays the bill.

ABOUT THE AUTHOR

Christine Easterfield is Principal Consultant for Cambashi. Previously her experience has been in geospatial asset management for the utility industry, assessing market needs and opportunities, managing customer requirements, liaising with development teams and running global product introduction programmes.

Christine has over 20 years' experience in the software business, with roles in programming, training, consultancy and, latterly, product marketing management. During this time she has worked for a range of companies from multi-nationals to small start-ups, resulting in an understanding of how different sized organisations operate, grow and become successful. Christine has a Bachelors degree in Computational Sciences and a Masters degree in English Literature. She can be reached at *Christine.Easterfield@Cambashi.com*'.

Guest Editorial 2

The Role of Big Data Visualization and Analytics in the Utility Industry

By Brian Bradford

Big Data & Analytics: A Widespread Phenomenon

Many industries are beginning to realize the full potential of big data and the role of analytics. The amount of data we have access to has exponentially increased and implementing analytics into the equation is key for organizations to remain ahead of competitors. Companies must jump on the bandwagon now or risk being left in the dust as competitors leverage big data to execute innovative, valuable, real-time strategies.

According to research by McKinsey & Company (McKinsey), leaders in every sector will have to address big data's implications, since data is now a crucial part of production, labor, and capital. In 2009, almost all industries in the U.S. economy had at least 200 terabytes of stored data per company with more than 1,000 employees. By 2020, IDC predicts that the total digital universe will be 44 times bigger in 2020 than it was in 2009, totaling a staggering 35 zettabytes. Growth factors for data's potential include volume and detail of information captured by consumers and by enterprises, multimedia content, social media and the Internet of Things.

McKinsey studied healthcare in the U.S., U.S. retail and manufacturing, Europe's public sector, and global personal-location data. Big data provides value to each of these domains. For example, retailers can use it to increase their operating margin, the healthcare industry can create more than US$300 billion in value each year and users of services that are powered by personal-location data could rake in US$600 billion in consumer surplus.

McKinsey Global Institute (MGI) the business and economics research arm of McKinsey also identified several ways that big data can add organizational value. Big data makes information more transparent and usable. As companies are able to store increased amounts of data, performance information is more accurate and detailed, leading to better results. Forward-thinking companies use sophisticated analytics to make better management decisions, and others are using vast information for forecasting purposes. Big data also provides a more specific customer segmentation model to develop the next generation services and products (think information gathered from sensors).

Utility Industry Challenge: Overwhelming Amount of Grid Data

As big data and analytics are playing a bigger role than ever across many industries, utilities are beginning to realize the potential in the space. In developing a modern electric grid, utilities have shifted from simply adding new hardware and software applications to completely reinventing operational technology in the utility business.

Due to the availability of funding from the American Recovery and Reinvestment Act of 2009, many utilities have begun to install the necessary foundational infrastructure and communications technologies. Recent advancements in smart grid devices and applications are creating significant increases in the amount of data now available. The ability to process and make sense of the vast amount of data that is being stored and archived is the next grid modernization challenge.

Opportunity: Utilizing Untapped Operational Data and Turning it into Actionable Results

There is no doubt that the utility industry is a complex electrical, communications, IT, and human network. It takes deep domain expertise to understand these intricacies and to create value from the large amounts of data the network generates.

Big data and analytics will trump any other previously developed technology and become the foundation to optimize all current and future smart grid technology. There is a steady convergence of operation technology and information technology that is revolutionizing the way that utilities operate their networks. Transforming raw data into contextual information, analytics will create actionable knowledge and inform decision making – creating a powerful, winning, and sustainable business advantage.

Utilities are inundated with data that modern grid technologies produce. Real-time applications, smart meters, weather information, social media data, and information stemming from any of the operational components of the grid such as the outage management system (OMS), distribution management system (DMS) or supervisory control and data acquisition systems (SCADA) can yield overwhelming amounts of information. Utilities must take a deep dive into what increasing data means to their traditional operations and make the necessary strategy adjustments to improve ROI.

Solving Big Data Challenges

To help utilities effectively manage big data going forward, the marriage of data, machines and people is vital as found in the Industrial Internet (November 2012). It represents an open, global ecosystem that will allow industrial companies to move away from simply a break-fix model to a predict-and-prevent model. The open, standard protocols will enable new waves of innovation for managing, analyzing, visualizing, and controlling machines to drive intelligent collaboration.

The Industrial Internet focuses on bringing the analytical intelligence to predict and prevent problems by getting the right information to the right people at the right time. It will lead to higher levels of efficiency and productivity. For example, it has the potential to remove US$150B total in waste from major industries such as energy, healthcare, aviation, rail, oil and gas, and more. To maintain and grow the energy supply globally, US$1.9 trillion is spent every year. Just one percent savings will equal US$19B each year, which translates to US$285B over 15 years.

Industrial Internet Meets Electric Utilities

One of the first Industrial Internet products was launched in early 2013 at DistribuTECH. Grid IQ™ Insight, a new grid analytics solution, analyzes and visualizes terabytes of big data to help utilities maximize reliability and efficiency of the electrical grid.

The technology helps utilities meet their needs by managing data from the electrical grid. The platform consolidates data from a broad mix of sources, including existing grid management systems, smart meters and other intelligent grid power equipment, sensors, weather monitoring, and even unstructured social media content. It takes terabytes of data and uses advanced analytics to generate actionable information that help to predict and proactively resolve issues that impact the performance of today's power grid. Data helps to drive better behaviors and patterns, which allows utilities to improve the ability to meet the expectations of its consumers.

The concept for this solution began more than two years ago, and is an example of integrating energy hardware and software tools to enhance visibility and control to the grid. The knowledge gained through tools like this combined with deep domain expertise of how all of the systems work together leads to powerful utility innovation. Many industrial companies like GE recognize big data analytics as a crucial next step for utilities to maximize the value of their data and systems.

Industrial Internet platforms offer numerous benefits to utility customers, including:

- Helping utilities to quickly identify and solve some of their most pressing data challenges, with data analytics and domain expertise
- Providing real-time information in a closed loop system to help utility companies better visualize, analyze and optimize data on the grid
- Innovation through an iterative rapid prototype process that has minimal disruption to utility resources
- Hosting a developing commercial library of analytic applications that spans across the grid from the time electrons leave the power station to when they are consumed by the end user

Solar energy installations have increased 116 percent year-to-year, but most utilities cannot track distributed energy day-to-day. This solution can combine solar interconnection, weather, and meter data to model distributed energy's effects on network reliability. It also tells customers how much money can be saved on a daily basis by utilizing solar power.

A utility's smart meter platform transmits massive amounts of energy consumption data – think hundreds of millions of readings and many gigabytes of data. Utilities face the challenge of not only collecting the data, but managing and storing it as well. The technology analyzes smart meter, customer, and network data to help utilities and consumers improve their energy efficiency, reduce revenue loss and better understand energy consumption trends.

According to Electric Power Research Institute (EPRI), power outages and power quality disturbances greatly affect the U.S. economy, costing utilities and consumers more than US$150 billion annually. The grid analytics solution enables utilities to identify system outages quickly via improved visualization and analysis of their systems, minimizing outage times and greatly reducing costs associated with extended system outages.

Approximately 500 million registered Twitter users generate over 340 million tweets daily. That's about 320 thousand daily tweets from a typical utility's customer base. The social media analysis component can identify trouble spots on Twitter – and therefore outage locations – before customers call in. This enables the energy provider to respond more quickly to outages thereby minimizing customer disruption.

Putting the Platform to Use

One customer chose the combination of GE's outage management system (OMS), distribution management system (DMS) and grid analytics solutions. The offering is designed to capture reliability data during restoration processes and to provide the resulting operational data that reflects the performance of the utility during specific time periods, weather events or for an entire year. The system is able to:

- combine and analyze frequency and duration of every single outage
- voltage levels across the grid
- compensation currently and compared to other time periods
- weather histograms including rainfall, wind data, and temperature data all in real-time on one computer monitor.

When it comes time to report to regulators, the information can be constructed in a way that aligns with the regulatory standards, such as in different geographic views. All indicators can be calculated per electrical set, city, circuit, and installation. Additionally, the platform helps the utility improve prioritization of outages based on the number of consumers, and view critical customers or the size of the customers affected in one system.

A Natural Fit for Geospatial Needs

As utilities become more aware of the power of Geographic Information Systems (GIS) data, they are asking how they can extend the reach of their own GIS data and gain higher return on investment. With strong engineering capabilities within their companies, utilities are keen to increase productivity based on their ability to access, visualize, and analyze their grid data.

For this reason, Google recently integrated Google Maps data into GE's Smallworld™ electrical, telecommunications, and gas applications. The geospatial product suite helps industries design and model complex network infrastructures while supporting asset management lifecycle processes. The platform will help utilities increase productivity based on the ability to visualize and analyze data. The partnership will also enhance the existing network visualization capabilities and will allow utility customers to receive incremental efficiency and productivity of operations in the field. Utility users are able to view a familiar, simple, and intuitive user interface overlaid on their geospatial applications. By enhancing the ability to visualize data on a map, utility customers will be able to quickly provide their end-use customers with important information such as outage restoration times and will help to more efficiently manage their network assets. The agreement will also deliver solutions for applications such as business intelligence, engineering, web clients, schematics, corridor management, and enterprise gateway.

Google's mapping content will form an integral part of a developed set of focused applications for the web, mobile devices, and desktops and will strengthen existing geospatial capabilities of Smallworld products. The DMS and OMS also will utilize Google's mapping content in the context of operational control of electricity networks. For field operators Google's Android platform will be utilized to augment the existing portfolio of mobile products.

Next Steps for the Industry

With the utility industry becoming more complex and evolving in such a significant way, utilities must adapt to a more proactive approach in managing increasing power demand. They must shift to real-time and predictive analytics, moving away from the traditional reactive 'as needed' model.

Utilities can do this through taking additional risk, investing in cutting-edge technologies and partnering with advanced technology teams in R&D efforts. A modernized grid is essentially an 'energy Internet,' delivering real-time information and knowledge – providing the visibility and control to empower smarter energy choices and deliver unprecedented new benefits. By connecting minds and machines, we can push the boundaries of physical and material sciences to make the electric grid more efficient and reliable.

ABOUT THE AUTHOR

Brian Bradford is Director of Product Marketing for Software Solutions under GE Energy Management's Digital Energy business. He is responsible for the strategy, commercialization and positioning of all DE's grid modernization software businesses which are targeted at providing visibility, control, and analytics of electricity throughout the grid.

Brian began his career in energy in the mid-nineties and proceeded with a seven year career at Enron Corporation where he focused on business development and strategy in the finance, international, and broadband divisions. After Enron, he was a new business development consultant for Mirant Corp and the Jamaica Public Service Company. In 2005 he became Director of Strategy and New Business Development at NSTAR Corporation (now Northeast Utilities) and served as President of telecommunications subsidiary, NSTAR Communications Inc. Post NSTAR, he was Director of Strategy Consulting at clean technology start up GridPoint Inc. Brian joined the GE team in 2011. He has an MBA from Harvard Business School and an undergraduate degree in Finance from the Wharton School of the University of Pennsylvania.

PRODUCT SHOWCASE

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Smart grid projects can be deceiving.
The ultimate Smart Grid vision portrayed by many still remains nothing but a panacea. If you are interested in a practical, pragmatic vision of the Smart Grid and need your vision successfully realized, make us your partner.
If you want results instead of reports or marketing campaigns and want a Smart Grid strategy which is sustainable both post implementation and year after year, make us your partner.
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