



Electric Energy T&D

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DISPLAY TECHNOLOGIES AND THEIR IMPACT ON THE CONTROL ROOM



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POWERPOINTS

Tipping Your Cap-and-Trade



Many of you have likely heard the phrase 'May you live in interesting times.' It has long been thought to be an Ancient Chinese curse meaning 'May you experience much disorder and trouble in your life.' Apparently, it is neither Chinese nor ancient in origin but that's not up for debate here.

It does, however bring me to the issue of carbon tax and cap-and-trade. The 'interesting times' that we are heading into in my home province of Ontario are because we have recently entered into a cap-and-trade agreement with the province of Quebec and the state of California. Canada's federal government has thus far paid little more than lip service to the problem of climate change and the country remains one of the few in the world that is not part of the Kyoto Protocol. The government insists that any type of tax would be a job and economy killer. Interesting.

According to the Environmental Protection Agency (EPA):¹

Cap and trade is a market-based policy approach designed to protect human health and the environment by controlling large amounts of emissions from a group of sources. The policy first sets an aggressive cap, or maximum limit, on emissions. Sources covered by the program then receive authorizations to emit in the form of emissions allowances, with the total amount of allowances limited by the cap. Each emitting source can design its own compliance strategy in order to meet the overall reduction requirement, including the sale or purchase of allowances, installations of pollution controls, and implementation of efficiency measures, among other options. Individual control requirements are not specified under the programme, but each emission source must surrender allowances equal to its actual emissions in order to comply. Sources must also completely and accurately measure and report all emissions in a timely manner to guarantee that the overall cap is achieved.

The EPA goes on to say that a well-designed cap and trade program delivers:

- Greater environmental protection at lower cost
- Broad regional reductions, facilitating state efforts to address local impacts
- Early reductions, a result of allowance banking and market incentives
- Environmental integrity and transparent operations and results
- Fewer administrative costs to government and industry
- Efficiency and innovation incentives

- Incentives for doing better and consequences for doing worse
- Accounting for all emissions
- Partnership with existing requirements to ensure protection of the local population and environment

In an ideal world, cap-and-trade programmes require no prior approval, allowing sources to respond quickly to market conditions and government regulators.

Cap-and-trade has been used successfully in the U.S. to reduce emissions of sulphur dioxide and nitrous oxide, two key ingredients responsible for acid rain. Existing programmes include the Acid Rain Program and the NOx Budget Program – both have the force of federal and state standards behind them. Since the early 1980s, this policy has served to cut down acid rain-forming emissions by nearly half. The net result is a much healthier environment. The European Union has had the same system in place since 2005 to reduce greenhouse gas (GHG) emissions from approximately 10,000 industrial emitters. Tokyo, a city with a carbon footprint larger than many industrialized nations, set in motion its own cap-and-trade policy in 2010. The initiative applies to its most energy and carbon intensive organizations and aims to reduce emissions to 25 percent below levels by the year 2020.

The David Suzuki Foundation states that either cap-and-trade or a carbon tax would work. With respect to a carbon tax, the foundation explains:²

Pricing through a carbon tax is a powerful incentive. Governments have to encourage countries and households to pollute less by investing in cleaner technologies and adopting greener practices. The tax itself is a fee placed on GHG pollution mainly from burning fossil fuels. The tax puts a monetary price on the real costs imposed on our economy, our communities, and our planet by GHG emissions and the global warming they cause.

Under this system, the price to pollute sets the strength of the economic signal and determines the extent to which green choices are encouraged. For example, a stronger price on emissions will lead to more investment in cleaner energy sources such as solar and wind power. And although a carbon fee or tax makes polluting activities more expensive, it makes green technologies more affordable as the price signal increases over time. Most importantly, a carbon tax gets green solutions into use.



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Many industrialized countries have used carbon taxes to discourage fossil fuel emissions and promote clean energy. For example, Sweden has been able to reduce GHG emissions since 1991. Although a suite of other policies has also been used, the Swedish Ministry of Environment estimated the carbon tax has cut emissions by an additional 20 percent (as opposed to relying on regulations), enabling the country to achieve its 2012 target under the Kyoto Protocol. Sweden's policy tax has been credited with spurring the innovation and use of green heating technologies that have significantly phased out the burning of oil.

Sweden's carbon tax is \$140 per tonne of carbon pollution. Since the policy was introduced, Sweden's economy has grown by more than 100 percent and the country recently ranked fourth in the world on economic competitiveness.

In Canada, British Columbia and Quebec currently use carbon taxes as part of their strategies to reduce emissions and encourage investments in energy-efficiency and renewable energy.

There is much discussion about which system is the best way to put the brakes on GHG pollution. The simple answer is that it depends on how each system is designed thereby determining the environmental and economic efficacy.

For example:

1. How strong is the economic incentive (i.e., the carbon price) to reduce emissions and switch to cleaner energy?
2. To which emission sectors does the policy apply?
3. How are the revenues to be used? Are they invested in green infrastructure or corresponding tax breaks?

Experts claim that if both approaches are well-designed, the two options are quite similar and could even be used in tandem.

It's paramount that whatever programme or price is selected, it should be applied broadly in that country's economy and that the price on carbon pollution provide an adequate incentive for everyone – from the smallest household to the largest industry. The critical factor in reducing heat-trapping emissions is the strength of the economic signal. A stronger carbon price will jump-start more growth in clean, renewable energy and will encourage adoption of greener practices.

Both cap-and-trade and carbon taxes can work well as long as they are designed to provide a strong economic signal to get on board with cleaner energy. According to the Suzuki Foundation, some differences exist:³

Cap-and-trade has one key environmental advantage over a carbon tax: It provides more certainty about the amount of emissions reductions that will result and little certainty about the price of emissions (which is set by the emissions trading market). A carbon tax provides certainty about the price but little certainty about the amount of emissions reductions.

A carbon tax also has one key advantage: It is easier and quicker for governments to implement. A carbon tax can be very simple. It can rely on existing administrative structures

for taxing fuels and can therefore be implemented in just a few months. In theory, the same applies to cap-and-trade systems, but in practice they tend to be much more complex. More time is required to develop the necessary regulations, and they are more susceptible to lobbying and loopholes. Cap-and-trade also requires the establishment of an emissions trading market.

A colleague of mine in the U.S. recently sent me a note concerning California. The state has enacted its landmark climate legislation, AB 32, which requires California to reduce its GHG emissions to 1990 levels by 2020. To achieve this goal, the policy authorized the state's Air Resources Board to enact various mechanisms to reduce emissions: a cap-and-trade programme, a renewable portfolio standard (requiring utilities to get one-third of their electricity from renewable sources by 2020), a low carbon fuel standard, and others.

Under this mandate its economy is growing and carbon emissions are dropping. As of last year, there were 431,800 people employed in advanced energy – more than the entire motion picture, television, and radio industries. California is on track to grow to over 500,000 workers in the energy area this year.

Between 2006 (when AB 32 was signed into law) and 2013, California received more clean technology venture capital investment than all other states combined – USD21 billion versus USD19 billion total for the rest of the U.S. From January 2013 to June 2014 (during the second year of California's cap-and-trade policy) 491,400 jobs were added, a 3.3 percent growth. This outpaced the national average of 2.5 percent during the same period

Funds received from the distribution of emissions allowances as part of AB 32 Cap and Trade programme are deposited in the Greenhouse Gas Reduction Fund (GGRF) and, upon appropriation by the Legislature, must be used to further reduce emissions of GHGs. In 2012, the Legislature passed SB 535 and directed that, 25 percent of the moneys allocated from the GGRF must go to projects that provide a benefit to disadvantaged communities with a minimum of ten percent of the funds being set aside for projects located within disadvantaged communities. The biggest recipients of GGRF money to date are:

- High Speed Rail Authority (USD250 million)
- Air Resources Board (USD230 million for low-carbon transportation)
- Strategic Growth Council (USD130 million)
- Low-income weatherization program (USD75 million)

The numbers speak for themselves. Good luck to Ontario and Quebec with their cap-and-trade programmes. I only hope our federal government will one day see the light and start acting for the good of all Canadians and, by extension, our planet. Mmm – should be interesting!

¹ Cap and Trade. US EPA. <http://www.epa.gov/captrade/basic-info.html>

² Carbon tax or cap-and-trade. Climate solutions. Climate change. <http://www.davidsuzuki.org/issues/climate-change/science/climate>.

³ Ibid



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Customers give thumbs-up on awareness of and experience with FPL's energy-saving and billing programs

May 2015

Florida Power & Light

Company's (FPL's) energy-saving and billing programs have been ranked by customers as the best in the nation, according to the nationwide Utility Trusted Brand & Customer Engagement study conducted by Market Strategies International. The study, which is the result of responses from 40,000 residential customers nationwide, gave FPL high marks for the design and features of its programs and for delivering products that fit customer needs.

"We are extremely pleased to be recognized by our customers as the top product experience provider among all utilities nationwide," said Eric Silagy, president and CEO of FPL. "Each and every day we strive to improve the lives of our customers by delivering a value proposition that is second to none, built upon a suite of innovative products and services that help them save time and money and be more energy efficient. The rest of the equation is simple - educating customers on our products and services, and importantly, making it easy and fast for them to sign up."

The comprehensive customer relationship benchmark study ranks the 125 largest U.S. electric and gas utility companies (based on residential customer counts). FPL was ranked the top performer on overall product experience of more than 50 offerings across billing, payment, pricing, consumption management, electronic access and enhanced service support.

"The old adage that an educated customer is the best customer holds true in the utility industry," said Chris Oberle, senior vice president at Market Strategies. "And FPL has done a great job of both offering innovative energy-savings and billing programs and teaching customers how to take advantage of them."

FPL typical residential customer bills are the lowest in Florida and 30 percent below the national average.

Advanced energy tools on FPL's website help customers save even more. For example, the Online Home Energy Survey helps customers reduce their bills further with personalized energy-savings plans, tips and recommendations. The survey is integrated with each customer's FPL Energy Dashboard - which is updated automatically with hourly, daily and monthly energy usage data, monthly bill amounts, local temperature readings and more - so tracking and managing energy costs is easier than ever. Customers can visit FPL.com/easytosave to learn more.

Dominion Honors 15 individuals as 2014 Volunteers of the Year

May 2015

This year marks 31 years of goodwill and more than 100,000 hours of service and giving to neighbors as Dominion recognizes the contributions of 15 individuals during its Volunteer of the Year Celebration.

"Volunteer service is embedded in our core values," said Thomas F. Farrell II, chairman, president and chief executive officer. "It is a fundamental aspect of the commitment our company has made to be an engaged, responsible corporate citizen and to enhance the quality of community life wherever we operate."

Hailing from Connecticut, Ohio, Pennsylvania, Virginia and West Virginia, the 2014 Volunteers of the Year will be recognized at awards ceremonies in Richmond, Va. and Akron, Ohio.

These Dominion volunteers dedicate their time and skills to an array of charitable activities -- from helping homeless mothers complete job training to providing medical care for widows and orphans in Guatemala to volunteering at the Veterans Administration Hospital. A wide range of nonprofit organizations have benefited, including those working to revitalize communities, meet human needs, promote education and improve the environment.

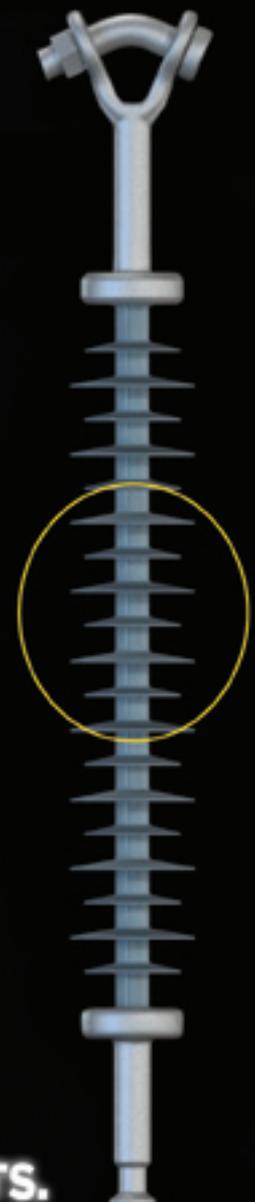
In 2014, Dominion and Dominion's charitable foundation and employees invested more than \$18 million in programs that help improve the quality of life for people in the communities where they work and live.

On April 30, Dominion's longstanding volunteer program received the 2015 Governor's Volunteerism and Community Service Award. The recognition spotlights the outstanding efforts individual and organization volunteers make on behalf of citizens throughout Virginia. For more information about the award, visit: http://www.vaservice.org/go/news/governor_honors_2015_volunteerism_award_winners.

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EHRC and Government of Canada Launch Career Mentorship Program for Women in Electricity Industry

May 2015

Electricity Human Resources Canada (EHRC), announced Connected Women a national mentorship model for women seeking to enter or advance in the electricity and renewable energy industry. Funded by Status of Women Canada, the program will be piloted with graduates of Algonquin College's Women in Electrical Engineering Technology program (WEET).

Partners include Hydro One, Ontario Power Generation, Manitoba Hydro and Hydro Ottawa, along with Women in Nuclear-Canada (WiN), International Brotherhood Electrical Workers (IBEW), Power Worker's Union (PWU), University of Toronto, Electrofederation and WESCO.

Conception of the mentorship program originated from EHRC's "Bridging the Gap" project, an initiative to increase female representation in the electricity industry. According to EHRC's 2011 Power in Motion Report, women account for fewer than 5 percent of jobs in trades, and 25 percent of the total electricity industry workforce in Canada.

"Our Government's number one priority is to create jobs and opportunities for all Canadians. One of the ways we do this is by supporting community-based projects that support economic security and prosperity for women. We know that when women succeed, Canada succeeds."

The Honourable Dr. K. Kellie Leitch, P.C., O.Ont., M.P., Minister of Labour and Minister of Status of Women

"I am proud of our Government's efforts across the country to create new economic opportunities for women. Through our Government's initiative in collaboration with Electricity Human Resources Canada, we will support the economic advancement of women in the electricity sector, which is so important to our economy."

Joan Crockatt, Member of Parliament for Calgary - Centre

"Women will play a key role in the electricity sector's ongoing success as it works to overcome significant labour market challenges in the years ahead. This Government of Canada funding will allow us to provide women with mentoring opportunities that will help them to advance within the industry, which will strengthen the electricity industry and prepare it to meet current and future demands."

Norm Fraser, Chair of the Board, Electricity Human Resources Canada

"Our mission at Algonquin is to transform hopes and dreams into lifelong career success, and through this program women entering the electrical sector will build the connections they need to be even more successful. We are pleased to be a part of this pilot and want to thank the Status of Women in Canada and Electricity Human Resources Canada for their support of our students."

Cheryl Jensen, President, Algonquin College

About the Electricity Industry Mentorship Program

- Funding for this project was announced by Status of Women Canada, "Harper Government helps women advance in the electricity industry," April 23, 2015.
- The program will result in research and tools that advances opportunities and support for women in the electricity sector.
- It will provide women the opportunity to receive guidance from women working in the industry. Defined processes will ensure that women have extra support, particularly when transitioning into the sector.
- The project will focus on models built for women, along with sustainable solutions. It will identify the most innovative and successful best practices, and apply these insights into development of the electricity model.
- Partners include Hydro One, Manitoba Hydro, Ontario Power Generation and Hydro Ottawa. Utility companies across the country, along with women who would like to be considered as mentors, are encouraged to participate by contacting EHRC.

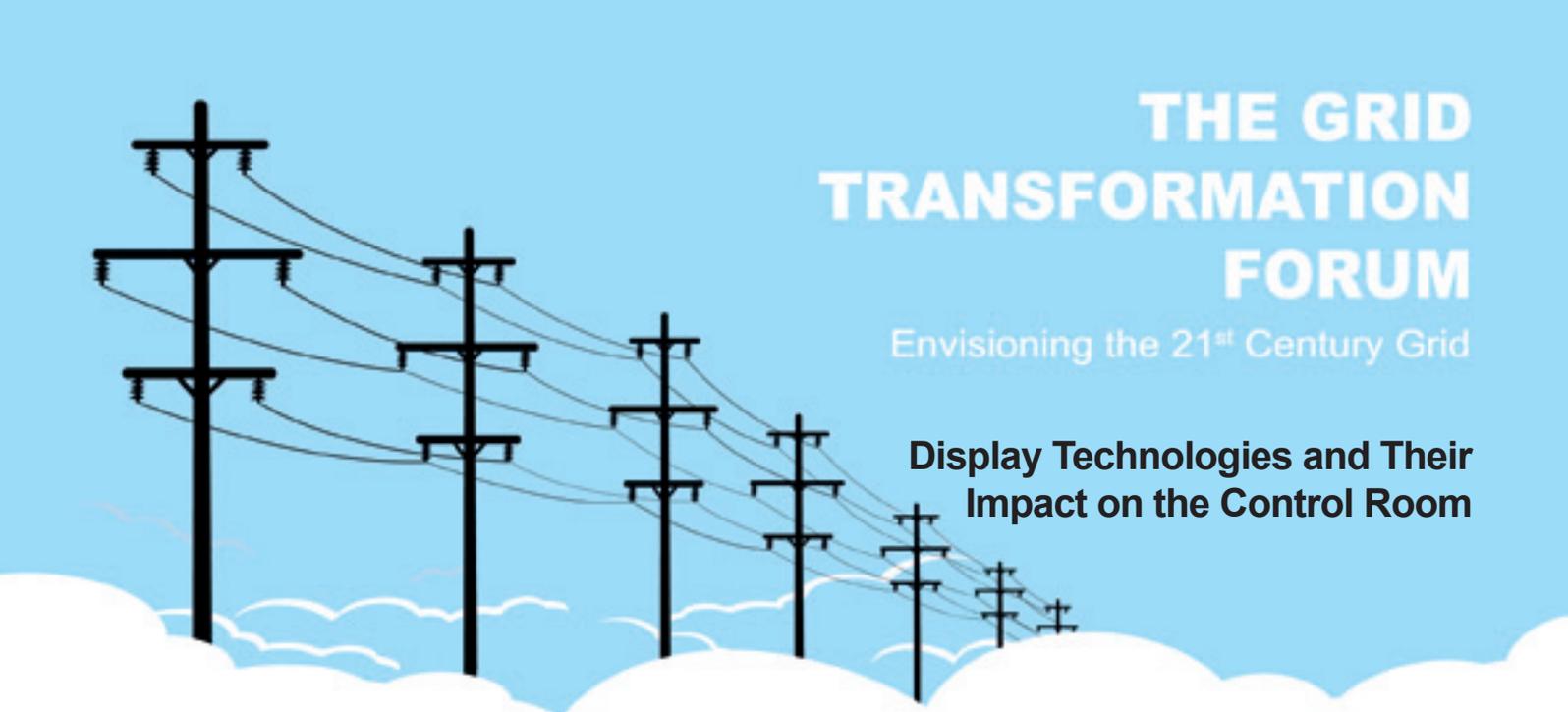
Duke Energy Indiana statement on IURC grid modernization order

May 2015

Today (5/11), Duke Energy issued the following statement in response to the Indiana Utility Regulatory Commission's May 8, 2015 denial of the company's Indiana grid modernization proposal:

We're still reviewing the order and considering our options, but we remain committed to making critically needed investments to modernize our system for the benefit of our customers. We expect to file with the Indiana Utility Regulatory Commission a revised plan that responds to the guidance given and the issues raised in the commission's order. This is one of the first times this new law has been interpreted, and it's being clarified for all Indiana utilities at the commission and in the Indiana Court of Appeals.

This is an important initiative, and reliable energy depends on thousands of miles of power lines moving electricity from place to place. Our electric grid is aging and many components need to be updated and replaced. There's also advanced technology now that can pinpoint power outages, speed service restoration and provide for better, faster communication with customers. We need to modernize our electric grid and bring our system into the 21st century. It's a plan that also generates jobs and investment in Indiana.



THE GRID TRANSFORMATION FORUM

Envisioning the 21st Century Grid

Display Technologies and Their Impact on the Control Room

As we continue to modernize our transmission grid, the control room, whether in a utility, RTO or ISO, grows more and more crucial. We've asked Charles Davis, Director of Engineering at Mitsubishi Electric's US Visual and Imaging Systems Division, to share his views on the display technologies impacting the control room today and in the future.

EET&D: What type of display technologies are in use today in control rooms?

Davis: There are many, among them older front projection systems, edge-blended direct throw rear-projection systems, legacy lamp-based rear projection cubes, dynamic tile boards, thin bezel LCD, and LED-based rear projection cubes.

For new purchases, however, most utilities and ISOs consider only thin bezel LCD panels with LED backlights and LED-based DLP rear projection cubes. Some applications can manage with thin bezel LCDs, as long as they can tolerate the larger image-to-image gap, but LCD is far from ideal in a control room operating 24x7x365. Inherent aging artifacts can lead to color shifts, image retention and image staining, and the panel lifetimes are, at best, only in the 50,000-hour range.

For mission-critical control rooms, LED-based rear projection cubes are a far better choice. LED cubes have much smaller image-to-image gaps than thin bezel LCD. They have extremely long lifetimes (approximately 80,000 to 100,000 hours), they don't suffer from aging artifacts, and they require little to no maintenance over the display lifetime.

EET&D: What types of display technologies are trending as future options?

Davis: The three that come to mind are LED upgrade engines, OLED panels and narrow pixel pitch direct LED technology.

One of the major downsides to the lamp-based technology still in use in many control rooms is that lamps must be replaced frequently, at a cost and downtime that are undesirable in a control room environment. A new alternative is to replace lamp-based engines with an LED-based

upgrade engine. Since all the structural components and screens can be reused, the downtime and overall cost to make the change is greatly reduced. There is considerable interest in this option.

OLED technology enables very thin displays with very high contrast ratios. As this technology expands in the consumer market, I expect it will make its way into the control room. Today the panels are very expensive to produce and there are questions regarding lifetime, but as the technology matures it may become a viable option.

There is a lot of buzz about direct LED technology, familiar for its use in stadium video scoreboards but now becoming practical for many indoor, high-resolution applications. Advantages include the fact that direct LED components are seamless, very bright and relatively thin. Currently, however, this technology is extremely expensive, the pixel size is too large for most control rooms and many questions remain unanswered about long-term reliability and performance. Still, I believe this technology will become more viable over the next few years.

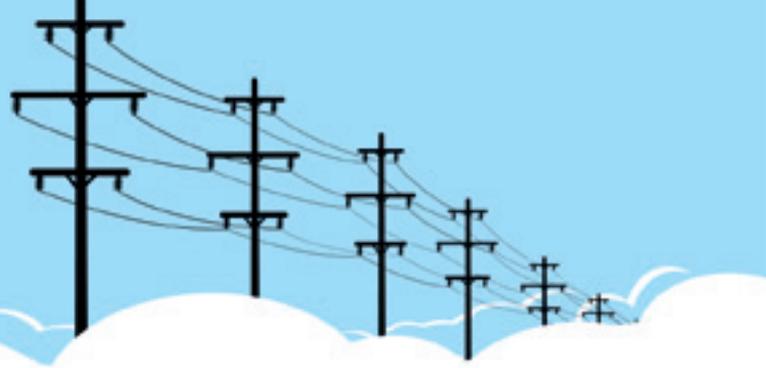
EET&D: What is the difference in a hardware-based controller versus a software-based controller in a video wall?

Davis: All video wall controllers are software-based to some extent. A hardware-based controller has a centralized processing unit with display management software that allows users to position any computer or video source anywhere on the display wall and scale it to the desired size. Graphics cards drive the displays and capture cards can accept a wide range of analog or digital inputs. In some cases, the controller may accept IP sources.

A software-based controller is more of a network solution. The software runs on off-the-shelf PCs and servers that manage and decode content accessed from the network to drive the displays. Network-based solutions are very attractive for control rooms that are running SCADA applications, since they can run on a server and the content can be displayed from the application pixel-for-pixel on the video wall. Software-based controllers also open the door for collaboration between users across multiple sites.

THE GRID TRANSFORMATION FORUM

Envisioning the 21st Century Grid



EET&D: What is the difference between a liquid-cooled versus an air-cooled video wall? What are the pros and cons of each?

Davis: Proper cooling is the key to maintaining the lifetime of the LEDs in a rear-projection system. Even a small rise in the operating temperature of the LED can greatly diminish its lifetime. Both the liquid-cooled and the air-cooled systems can do a good job of controlling the temperature and insuring long life if designed properly.

The liquid-cooled system consists of a pump, hoses, reservoir and radiator. The pump is used to circulate liquid coolant through a cooling block to control the temperature of each LED. The heated liquid is then pumped to a radiator which is cooled by a fan and then returned to the cooling block.

The air-cooled system is similar in concept, but it uses a 'heat sink,' a one-piece design that combines a passive radiator with a heat pipe mounted directly to each LED module. A fan circulates air across the fins of the radiator to remove the heat.

Both of these methods provide excellent temperature control. The major downsides to liquid-cooling are that it requires a more complex setup more prone to failure, and that the pump must be replaced every 30,000 to 40,000 hours. The coolant must also be removed and replaced, requiring special care because the corrosive substance ethylene glycol is typically used.

To avoid the need for scheduled maintenance and resulting downtime, air-cooled systems are preferable in LED light engines.

EET&D: What factors should be taken into an account in designing the video wall?

Davis: We need to look very carefully at what content will be displayed, how it will be managed and how it will be arranged on the wall. We also need to consider how many operators will work in the control room and where they can best be placed in relation to the wall. The process is similar to creating a blueprint for a building, and it takes as much attention and discussion. Many users initially ask for the highest resolution displays available, but the viewing distances and content dictates what the required resolution must be. You may pay for a higher resolution that the operators will never see.

EET&D: How do you decide on the proper size and resolution for the video wall displays?

Davis: Pixel pitch, the distance between the center points of two adjoining pixels, is what's crucial, given how far the operators will be positioned from the video wall. That's because a video wall will be made up of a large number of individual displays that form a combined image. If our total pixel count is the same, it really doesn't matter if those individual displays are XGA, SXGA, UXGA or WUXGA. On the other hand, if the pixel pitch is too large or too small, readability will be compromised.

To determine the maximum pixel pitch we can use, we consider the fact that an image, in order to be sharp, must be free of any pixel structure. Since the limit of the human eye's ability to discern individual objects is about one arc minute, or 1/60th of one degree in our field of vision, we need pixels that are one arc minute or smaller. We use that fact, together with the distance from the closest operator to the video wall, to calculate the maximum pixel pitch of our displays.

To determine the minimum pixel pitch, we need to know the distance of the farthest control room operator and the font size of the text to be displayed. Our goal is to use a display with pixels large enough that text and graphics are readable in the back of the room.

Once we know our content requirements, minimum and maximum pixel pitch, we can realistically look at display options. At this point initial cost, reliability and lifetime maintenance costs come into the equation.

EET&D: Of those, are certain factors more important than others?

Davis: Once we have a video wall design that will do the job we need to do, utilities consistently put reliability at the top of the list when choosing the individual displays. Ease of maintenance and total cost of ownership usually run a close second, and energy efficiency is becoming a factor as well. In all these categories, LED rear projection cubes score high marks and are currently the ideal choice for 24x7x365 control room applications.

EET&D: Thank you, Chuck, for your invaluable insights. Our readers will no doubt appreciate your thoughtful analysis of current and future display wall technology and its impact on the control room.



About the author

Charles Davis, Director of Engineering, Mitsubishi Electric US Visual and Imaging Systems Division, manages the design and development of display technology.

GREEN OVATIONS

Innovations in Green Technologies



Unlocking the grid edge: Open Standards are closer than you think

By Stuart McCafferty

If you're like me, you look at statistics about the growth of generation resources like solar installations and microgrids and can't help but think about the need to push intelligence farther out on the grid.

This past April 22, Earth Day, folks at the Solar Energy Industry Association (SEIA) announced that they'd be celebrating every two and half minutes. That's how often a new solar installation is completed in America. Today, the U.S. has some 20 gigawatts of installed solar capacity, enough to power about 4 million homes. The solar industry now employs 175,000 workers, more than Google, Apple, Facebook and Twitter combined, an SEIA news release noted.

Meanwhile, Navigant Research says that microgrids have moved beyond research and development and the technology is moving rapidly toward full-scale commercialization. That industry is forecasted by Navigant to grow from \$4.3 billion in 2013 to nearly \$20 billion in 2020.

Through distributed intelligence, asset owners can improve their situational awareness needed to more effectively monitor and control remote distributed resources without having to loop back to the control center and out to the grid again. Those round-trip decision-making processes through a central office can take several seconds and even minutes. Systems may need to shut down unnecessarily. With interoperable, intelligent devices and systems at the local level, decision making is faster and better tuned for that specific location.

How do we create interoperable communication and decision-making capabilities at the grid edge? One intriguing approach is explored in Duke Energy's *Distributed Intelligence Platform (DIP) Reference Architecture*. This well-received technical vision provides a blueprint for a platform that pushes computing power closer to grid-edge distributed resources while leveraging non-proprietary standards-based solutions. Vetted and tested through Duke's Coalition of the Willing, a consortium of smart grid equipment vendors who unlocked their technology's interfaces so they could integrate with other vendors' technologies using a reference architecture framework, the Duke architecture relies on a key technology enabler: an open field message bus.

At the SGIP Winter meeting in 2014, Stuart Laval from Duke Energy's Emerging Technology Group approached the Smart Grid Interoperability Panel (SGIP) to expand on their vision and codify an Open Field Message Bus (OpenFMB) approach into a set of standards, recruit other utility partners and facilitate the creation of an Internet of Things (IoT) ecosystem for utilities. Similar to how the Green Button initiative provides a common application programming interface (API) on the customer side of the meter, SGIP's OpenFMB will provide a common interface for grid devices and target new applications that enable interoperability on the utility side of the meter. The resulting SGIP project, OpenFMB, was launched this past February at DistribuTECH, and a fast-tracked approach to getting standards in place is now underway.

Where the bus is headed

For the non-engineers who might be reading this article, a good definition of a message bus appears in the book titled *Enterprise Integration Patterns* by Gregor Hohpe and Bobby Woolf. According to this team, a message bus is 'a combination of a common data model, a common command set, and a messaging infrastructure to allow different systems to communicate through a shared set of interfaces.' According to DOE's Chris Irwin, "The OpenFMB framework will provide a common bus to allow utilities to communicate across the common utility languages like IEEE 1547 for inverters, IEC 61850 for substation automation, ANSI C12 for meters, and IEC 61968/70 Common Information Model (CIM) for Enterprise back office integration."

In addition to a space already crowded with existing standards that struggle to complement each other, the industry lacks a one-size-fits-all software or hardware technology that can adequately enable true interoperability between new Distributed Energy Resource (DER) systems and the existing grid automation infrastructure. Consequently, an abstraction layer between devices in the field is needed to simplify the integration of our existing systems that are traditionally very difficult and complex to maintain and scale in the utility back office.

The overall vision for distributed intelligence architecture and unlocking the edges of the grid requires that the message bus is in the field, out on the grid, not in centralized data centers. And, in order to gain traction and allow true interoperability across devices and across vendors, the bus must be open. It leverages the same kind of standards used by IoT and data model standards such as IEC 61850, a substation automation standard from the International Electrotechnical Commission, IEC's 61968 Common Information Model (CIM) that supports exchange of information about an electrical system, or MultiSpeak from the National Rural Electric Cooperative Association, which was chosen by the National Institute of Standards and Technology (NIST) as a key operations standard in NIST's Smart Grid Standards Framework and Roadmap.

With this history and Duke's real-world experience with its reference architecture, SGIP is now taking the lead in tackling three different initiatives for 2015. First, we are working on two standards that will outline an OpenFMB framework specification and the details of a reference implementation. The specification will include the OpenFMB framework structure and approach for implementing field message bus devices in an interoperable way. The reference implementation will include a working example using existing industrial and IoT protocols with existing utility data models.

The SGIP OpenFMB team also is designing a use case to be evaluated at three different test beds. And, finally, we're supporting collaboration among different test-bed efforts through a related catalog of test bed projects that will provide a centralized repository and characterization of North American Smart Grid test beds. Each of these activities will contribute to faster access to standards and frameworks that facilitate peer-to-peer communication on the grid.

Fast-tracking standards development

Typically, standards take three to seven years of committee work, debate and voting before they are ratified. Yet, SGIP aims to have two standards written in eight months of work and voted on during first quarter of 2016.

Here is how we're doing it: using Duke Energy's reference architecture as a starting point, the OpenFMB team has begun working with the North American Energy Standards Board (NAESB) to support NAESB's standards-development processes. The SGIP's multi-stakeholder team supports the standards process with crucial requirements, quick feedback on documents as they are created, and verification that the requirements we've identified are being addressed.

Our OpenFMB team represents all kinds of players within the smart grid industry. We have asset owners, manufacturers of hardware, software and firmware, governments, testing and certification organizations, as well as regulators to represent consumers.

OpenFMB: Who's on the Team?

- ABB, Inc.
- American Electric Power (AEP)
- BC Hydro
- Coergon
- CPS Energy
- DTE Energy
- Duke Energy
- Electric Power Research Institute (EPRI)
- EnerNex LLC
- Ericsson
- Federal Energy Regulatory Commission
- FREEDM Systems Center
- General Electric Company
- Green Energy Corp
- GridIntellect
- IEEE Standards Association
- Itron, Inc.
- Kitu Systems, Inc.
- LocalGrid Technologies
- National Electrical Manufacturers Association (NEMA)
- National Institute of Standards and Technology (NIST)
- National Instruments
- National Renewable Energy Laboratory (NREL)
- North American Energy Standards Board (NAESB)
- Oak Ridge National Laboratory (ORNL)
- Omnetric Group
- OpenADR Alliance
- Pacific Northwest National Laboratory (PNNL)
- Pedernales Electric Cooperative
- PowerHub Systems
- Public Utilities Commission of Ohio
- Real-Time Innovations, Inc.
- Reef Energy Systems, LLC
- Reilley Associates
- SGIP 2.0 Inc.
- Southern California Edison
- Southern Company Services, Inc.
- UCAlug
- U.S. Department of Energy
- Upperbay Systems
- Xanthus Consulting International
- Xtensible Solutions

We also have a number of leading utilities participating, including the largest investor-owned utility in the U.S. – Charlotte, N.C.-based Duke Energy – as well as the nation's largest municipal utility – CPS Energy in San Antonio, Texas – and the nation's largest cooperative – Pedernales Electric – which also is in Texas. Other notable participating utilities include Ameren Services, American Electric Power, BC Hydro, DTE Energy, Southern California Edison and Southern Company Services.

Along with these utility giants, we have some major industry giants: ABB, General Electric, Itron, National Instruments and Omnetric Group. In addition, the team includes thinkers from some of the nation's top laboratories and research organizations, such as the Pacific Northwest National Lab (PNNL), the National Renewable Energy Lab (NREL), FREEDM Systems Center and the Electric Power Research Institute (EPRI). A complete list of players appears in the sidebar (on page 14).

Representatives from all of these organizations are coming together to contribute ideas and expertise, which SGIP is coordinating into comprehensive input for the standards writers. The team meets weekly by teleconference as well as through in-person meetings, with the most recent one held at the National Renewable Energy Lab in Golden, CO. SGIP is acting as the driving force, making sure the standards-creation process includes utilities, vendors and test beds to fully leverage prior work and create a truly interoperable open field message bus framework. The standards informed by this multi-stakeholder group will be comprehensive enough to serve the broad array of industry participants.

Putting it to the test

The SGIP team also is creating microgrid use cases to test at three different microgrid test bed sites – NREL, CPS Energy, and Duke Energy. We are working with organizations such as UCA International Users Group (UCAIug), Electric Power Research Institute (EPRI), and the Industrial Internet Consortium (IIC) to help support and coordinate the testing activities. Already, other test beds have approached SGIP expressing an interest in the use cases. The idea is that no test bed will test the exact same configuration and equipment but will use the OpenFMB framework to show true interoperability across equipment, vendors and even technologies.

The use cases have already been defined and UML models are under development. The first deals with the unintentional islanding from grid-connected mode due to one of two scenarios: a larger grid outage or a security threat.

In the first scenario, a grid outage is detected by an island recloser at the point of common coupling (PCC) and initiates the unintentional islanding transition. In the second scenario, a security event detected by the security platform notifies the island recloser at the PCC to start the unintentional islanding transition. Upon opening of the recloser at the PCC, the battery inverter receives the recloser open status and switches from current-source mode to voltage-source mode, which initiates the microgrid controller to begin optimizing the local microgrid in island mode. The microgrid controller calculates how long it can remain in islanded mode and provides regular status updates to the headend systems.

Benefits of OpenFMB

- Coordinated self-optimization where the volume of local data overwhelms the capability to transfer the data elsewhere
- Low latency for situations where centralized sites are too far away to respond promptly
- Resiliency when portions of the grid are segmented
- Open, observable, and auditable interfaces at multiple scales for interoperability
- Interoperability with existing plant and without rip-and-replace requirements
- Potential unified backhaul for reduced OPEX, simplified management and enhanced security

The second microgrid use case deals with normal daily operations of a microgrid, both grid connected and islanded. The use case models activity for day-ahead and intra-day scheduling, and it also examines internal microgrid optimization as well as optimization with power export.

The use cases will be finalized in May, setting the stage for an exciting summer as SGIP OpenFMB team members work with utility engineers at the three different microgrid test beds. We will coordinate the effort, working with utilities, test beds and vendors to support the use case implementation. The busy summer will be followed by a busier autumn when demonstrations are conducted at EPRI in September and at the SGIP annual conference the first week of November in New Orleans.

Who's doing what with test beds?

In conjunction with the OpenFMB test bed coordination activities, the SGIP team is developing a Catalog of Test Beds for North America. We have a list of 52 different smart grid test beds in North America and are conducting surveys of test bed leads to gather information on the type of testing the group is doing, the equipment in place, how others can collaborate on the project, whether there are costs for participation, the level of testing underway, simulation capabilities and other details. The information gathered will help identify opportunities for collaboration across test beds and identify gaps in testing that need to be filled. The SGIP plans to assist its utility and vendor members to locate opportunities for hands-on interoperability field testing on their own systems and equipment.

SGIP's efforts stem from the belief that microgrids and distributed resources are capable of providing even greater potential with a mixture of centralized command and control and distributed intelligence. But, SGIP members and staff also recognize the interoperability gaps that currently exist for utilities. As power delivery becomes increasingly localized, distributed intelligence will move from a nice-to-have notion to a must-have requirement for optimized grid operations.

Ultimately, all SGIP activities – the Catalog of Test Beds, the microgrid use cases, and the standards-writing support – will be completed by SGI, by year-end 2015. This is an aggressive schedule, but the team is confident and truly engaged as a collaborative machine with field device interoperability and distributed intelligence as the goal. SGIP is proud to be part of the efforts that will codify these requirements into industry standards.

If you're interested in learning more about the OpenFMB project and joining this effort, please contact info@sgip.org.

About the Author



A prominent contributor and technologist in the utility industry, **Stuart McCafferty** has lead large multi-stakeholder collaborative programs. He is the VP of Operations at SGIP where he oversees all operational aspects of programs to advance and accelerate grid modernization. In 2013, he received the international Distinguished Project Award from the Project Management Institute (PMI) for his work on SGIP programs.

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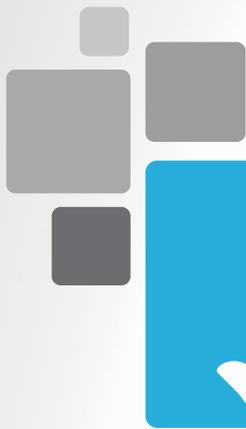
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From Research to Action

Advancing the Integrated Grid: Distributed Energy Resource Management Systems (DERMS)

By Dr. Gerald R. Gray, Dr. John Simmins, and Brian Seal

Battery storage, solar and wind generation, as well as other distributed energy resources (DER) promise clean energy as well as grid stability benefits. Managing the growing penetration of these resources is becoming a challenge. Coordinated control of these resources depends on communication between back-office systems and devices.

When Distributed Energy Resources (DER) were first being deployed at a scale to become interesting, they typically used inverters to convert direct current (DC) into AC that is synced with the grid. (Wind turbines convert 'wild' un-synced AC, to steady state DC, then do the AC conversion and syncing with the grid.) Various DER have clean energy benefits or work in combination resources such as wind/solar to mitigate the deleterious effects of unpredictable, variable generation. Additionally, while DER is often touted as a means to provide ancillary services on the grid to stabilize disruptions, the fact is at certain penetrations and locations, DER is the source of the disturbance.

Enter the smart inverter. Beginning in 2008, the Electric Power Resource Institute (EPRI) led an initiative for the industry to define a common set of smart inverter functions. This was a very successful effort with international participation and manufacturers and utilities coming to agreement on what common functions were needed and practical given the state of the technology. Once a menu of standard functions was in place, standard protocols (languages) were developed to communicate settings and status data with the smart inverters. The resulting standard (IEC 61850-90-7) defines these functions and it has been successfully mapped to communication standards such as DNP3, SunSpec Modbus, and Smart Energy Profile 2 (SEP2).

These developments have become the foundation upon which grid codes are being developed worldwide. In the context of DER, grid codes are the laws that dictate what is allowed to be connected to the grid. Grid codes are mandates that require certain grid-supportive characteristics and are put in place in order to enable the grid to support increasing levels of DER. In some cases, grid codes are created at the national level.

The German medium and low voltage grid codes were among the first and most extensive examples of a national grid code. In the US, California is revising the state's 'Rule 21' which is a code at the state level. Grid codes generally reference the standards, such as the IEC smart inverter standard and communication protocol standards. Such references benefit the manufacturers by providing more consistency in what is needed in the marketplace¹.

The next challenge to be addressed is how to manage the communication to all of these devices, especially as the number of deployed resources grows rapidly. The aggregate impact of many small DER, such as residential photovoltaic (PV) systems, is like that of large DER. Makers of distribution management systems (DMS) and utility control room operators typically do not want to view numerous small-scale DER on a device by device basis. They also do not want to view the numerous smart inverter functions and the detailed parameters involved with configuring each function. That level of control is too granular to be useful in the present distribution management environment where there are typically just a few control devices and basic on/off or up/down settings.

The clear distinction between the many field devices with many functional capabilities and the control center need for simplicity creates a need for DER management systems, or DERMS. In view of this, EPRI began work with the US Department of Energy, National Institute of Standards and Technology, Smart Grid Interoperability Panel, and other entities in late 2012 to address this need. EPRI gathered a host of industry stakeholders to coalesce around a common set of use cases that are fitting for DER integration at the enterprise level. This body of work was aimed at addressing the needs for DMS integration of DER, including utility-to-aggregator interfaces and substation or feeder-level management of DER. The core set of use cases is based on the need to manage groups of DER, do maintenance on these groups (creating/deleting groups, adding or removing members), status monitoring of the group, dispatching of the group for real and reactive power, and forecasting of a group's capabilities.

From Research to Action

Nominally the DERMS could be thought of as another edge system such as an advanced metering infrastructure (AMI) head-end system that manages the communication with meters, performing meter reading and handling commands and events, while communicating with other back-office systems such as a customer information system (CIS) or meter data management system (MDMS). A DERMS would communicate with individual DER in the field via any of several standardized protocols and would communicate with other interested back-office systems about the status and capabilities of the DER in aggregate. ‘Interested’ systems might be, for example, a Distribution Management System (DMS) for group capabilities, an Outage Management System (OMS) for any pertinent events, or a Geospatial Information System (GIS) for locational data or for the nameplate characteristics (rated DER capacity) if a utility is also using the GIS for asset management. The use cases and communication standards for utility application to application or business-to-business integration is typically via Common Information Model (CIM) standard (in this case IEC 61968-100) or MultiSpeak.™ Other protocols are also possible and could be adapted to support the needs of managing DER in aggregate groups. A DERMS might receive a request from a utility DMS that in essence says, “How many vars can you give me at this location, at this time, for this group?” The DERMS would manage the communication to all of the resources that make up that group, determine the capability, and respond with the vars, duration (how long it could support that request), and the degree of confidence it could meet the request based on its internal algorithms.

During the development of these DERMS use cases EPRI collaborated with the MultiSpeak and IEC standards development organizations (SDOs) so that the messages to support these use cases would be consistent across the two enterprise integration standards. While some of the internal organizing principles are somewhat different, this was a very successful effort to align these standards. During 2013, the DER group monitoring and managing messages were defined using XML Schema Definition (XSD) and published.

However, just having a standard (or a draft of a standard) on paper is not sufficient to prove that it works or to convince industry stakeholders to move forward with products and programs based on the standard. What is needed to close the ‘action’ gap is for product manufacturers to implement the new capabilities into their products and test (demonstrate

their capabilities relative to the standard). To facilitate this vendors want specific interpretation and guidance as it relates to the standard. Historically if this guidance is missing, vendors may have different interpretations of the meaning of a standard and implement it in ways that are not interoperable.

To close this gap EPRI worked with industry stakeholders to define a set of tests, with example XML validated against the XSDs (to ensure compliance) which illustrated what a typical request or reply would look like for each of the test cases. Then, late in 2014, EPRI led a testing workshop, cohosted by the Department of Energy and the National Renewable Energy Lab (NREL) and hosted at the Energy Systems Integration Facility (ESIF) in Golden, CO. The workshop was very successful with Spiraer, NeBland Software, Boreas Group, Schneider Electric, and Smarter Grid Solutions participating. Additionally, EPRI has continued to develop a Semantic Standard Test Harness to support testing and validation of these and other messages, which is hosted on an Amazon cloud server so that it is available 24x7 for other parties that might be interested in developing DERMS-compliant messages.

Architectural Considerations

While nominally envisioned as an edge server within the utility data center because the message standards are agnostic to architecture (being based on web services) the DERMS could just as well be hosted in the cloud, either managed by a third party aggregator or by the utility. Additionally, for utilities that want to manage the communications and control closer to the resources, the DERMS could just as well be a ‘black box’ deployed in the grid, perhaps as a microgrid controller, with the business logic of the control inside the box, while it still speaks the appropriate protocol to devices in the field (e.g. 61850, DNP) and notifies the utility of group actions via CIM or MultiSpeak to the back-office.

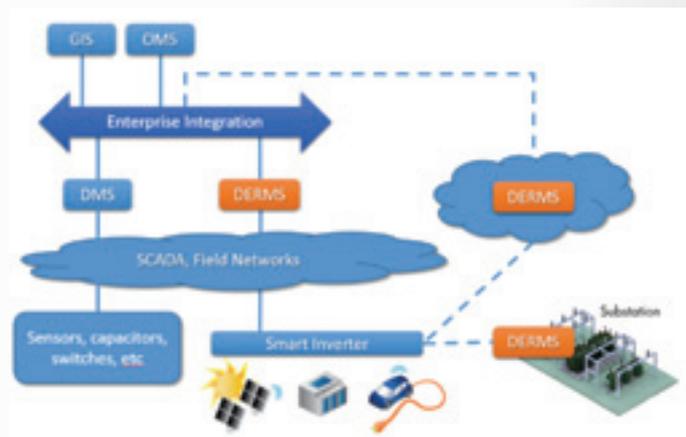


Figure 1 - Architecture alternatives that reflect the different ways that a DERMS could be deployed, at the utility, in the cloud, or in a substation



Standardization Efforts

This work will be officially codified in the next versions of the related CIM and MultiSpeak standards, (5.x for MultiSpeak, IEC 61968-5 for CIM). EPRI is supporting this work in partnership with DOE, NREL, vendors and other industry stakeholders. Plans are already being made to address additional use cases, and make some changes to existing messages based on feedback from vendors that participated in the testing workshop and from the standards development organizations (SDOs). It is anticipated that there will be another testing workshop to vet these changes and new capabilities in the later part of 2015.

Summary

This is definitely an exciting time marked by rapid changes in the capabilities of devices both in terms of load generation and communication capabilities. Via use cases of DERGroup membership, DERGroup status monitoring, and DERGroup forecast and dispatch, new enterprise level capabilities and control are being added just as the amount of DER penetration in the grid is increasing. This promises more reliable and granular control of grid resources even as diversity or energy source and architecture increases.

Reference

¹ A point of clarification, it is a bit of a misnomer to refer to this as the 'California standard.' While the California Public Utility Commission (CPUC) and the utilities in California are doing important work, the 'standard' is what is defined by the IEC. While it is very quickly being applied in California, it is in fact being used in numerous locations around the globe.

For more information:

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About the authors



Dr. Gerald R. Gray is a Technical Executive at the Electric Power Research Institute (EPRI). He leads the EPRI enterprise architecture and integration program. In this capacity Dr. Gray also participates in the development of numerous industry standards as a member of International Electrotechnical Committee (IEC) TC57, IEC TC8, and MultiSpeak® organizations. He is also participates in the Smart Grid Interoperability Panel as a member of the Smart Grid Architecture Committee (SGAC) and is a member of the GridWise® Architecture Council.

Dr. Gray has also worked with or contributed to the development of frameworks for topics such as the smart grid, sustainability, and big data. These frameworks include the SEI/CMU Smart Grid Maturity Model (SGMM), the Electric Power Sustainability Model (EPSMM), and the Utility Data Management Framework (UDMF). He earned a Masters of Administrative Sciences in Managing Information Systems from the University of Montana and a Doctor of Philosophy in Organization and Management with a specialization in Information Technology from Capella University.



Dr. John J. Simmins is a Technical Executive at the Electric Power Research Institute (EPRI) where he manages the Information and Communication Technology for Distribution project set. His current research focuses integrating back-office applications and integrating with devices and personnel in the field. Dr. Simmins also leads the EPRI efforts in the use of augmented reality, social media, data analytics, and visualization to improve grid resilience. Prior to joining EPRI Dr. Simmins was with Southern Maryland Electric Cooperative where he managed the engineering and operations applications. He received his B.S. and a Ph.D. in Ceramic Science from Alfred University.



Brian Seal is a Senior Technical Executive. As such he manages EPRI's Information and Communication Technology research in the areas of advanced metering, demand response, and integration of distributed energy resources. In this role, Brian has been actively involved in international efforts to create standards for interoperability of consumer appliances, solar inverters and smart meters.

Prior to joining EPRI in 2008, Brian worked for 20 years at Cellnet (now Landis+Gyr) and Schlumberger (now Itron) where he managed product design and development of utility metering and communication equipment. He received Bachelors and Master's degrees in Electrical Engineering from the Georgia Institute of Technology, is an active member of IEEE, IEC and other standards groups, and has been awarded several patents related to utility communication systems.

How to Make Sound Equipment Decisions

Key Considerations for New and Used Truck Purchasing

By Margaret Ann Walker

Deciding whether to buy a new or used bucket truck comes down to two things: what you need and what you can pay. Finding a balance between needs and costs may seem as much art as science, but you don't need to compromise either in the process; it's about finding the best fit for you.

Before You Start the Search

Budget and needs go hand-in-hand. Alex Senf, Altec Senior Account Manager with a well known equipment supplier walks his customers through a **NEADS** analysis before ever considering a final decision. This simple analysis, originally developed by Tom Hopkins, is critical to establishing a good starting point for an equipment search.

Now. What do you have now in terms of make, model, function, body type, etc.? If the answer to this is nothing, that's okay. Focus on what you want a piece of equipment to do for you.

Senf recommends starting out with the following spec details: platform size (one man or two); material handling or non-material handling; insulating or non-insulating; line body or flatbed; and under CDL or over CDL chassis.

Also, consulting with someone with a similar job application to gain experience with features found on different pieces of equipment can be beneficial.

Enjoy. What do you enjoy about that piece of equipment? Dedicate some time to discovering the features that make your specific job easier and those you can do without. Sometimes eliminating something simple like an extra bin or ladder compartment can equate to big savings.

"Often it's very easy to knock off several thousand dollars on the price of a truck if the buyer goes through a spec sheet, line by line, to decide what's needed and what isn't," said Senf.

Alter. What would you change? Consider the limitations of what you currently have. Do you need to lift personnel higher, prevent rusting, improve payload, eliminate engine idling?

Decisions. How are decisions made? This doesn't just include the process, but also who is involved in making the decisions. Including the right people in the decision making process ensures that costs/budget and needs/requirements for use stay balanced throughout the decision process.

Solutions. Listening well and understanding needs throughout the process leads to the best solutions for the seller and the buyer.

Purchasing New Equipment

No two purchases, or needs, are exactly the same. While every request is different, some take you to the realm of customization – a specific ladder rack or tool box, for example – that may only be available from a new equipment purchase.

Ed Hunter, President of Horizon Lighting in California, has purchased a variety of new and used trucks for his lighting maintenance and construction business.

"Many times, it's a tough decision whether to buy new or used," said Hunter. "I've had great experience

with both new and used purchases from Altec. Before making an investment, it's important to have a good understanding of what you're going to do with the truck including how high you need it to go, the unique locations of your job sites and the tool storage you need.

Like Senf suggests, testing other equipment is a great way to learn the features that make your job easier. When it comes to a piece of equipment that is being tested or considered, the features may be the most important aspect to analyze.



How to Make Sound Equipment Decisions

Key Considerations for New and Used Truck Purchasing

“A lot of times, a customer will want a truck exactly like one they’ve seen used by someone else,” said Senf. “I always ask them why. Without going over each spec, line by line, the customer could end up paying thousands of dollars more than what they really need.”

Before and After

Figuring out what you need your equipment to do for you is the first step. Then what? It’s time to think about the future and how you will use and care for equipment.

Service and repair are part of owning and maintaining any piece of equipment. Working with an equipment provider that offers convenient access to mobile technicians and service centers provides peace of mind.

“With any equipment purchase, make sure the company you’re doing business with has the ability to provide service and support after the sale,” said Senf.

For some owners, the costs incurred from downtime sometimes associated with older pieces of equipment are enough to invest in a newer unit with less mileage.

“When I have a truck go down, that kills my business,” continued Hunter. “Having a reliable piece of equipment doesn’t always mean new, but the new trucks we have purchased have had a much better track record for repair costs over a long period of time than the used vehicles.”

Purchasing Used Equipment

Since used equipment typically costs about half the price of new, it’s often a cost-effective choice for some buyers. With the proper planning, purchasing used equipment can mean

reduced acquisition costs and a dependable, certified used equipment investment.

Casey Tolley, Altec Account Manager, notes that advertised used equipment prices don’t vary too greatly from dealer to dealer. What can vary is the diligence associated with inspecting and testing used equipment. “Make sure your equipment has undergone an annual service inspection including dielectric testing on the boom, as well as annual testing on the unit and chassis,” said Tolley.

With all equipment, routine maintenance and service are an inevitable part of ownership. Working with a dealer that has inspected your equipment and can help provide maintenance can make the wear and tear on your equipment, and you, a lot less stressful.

“I choose Altec because I like dealing directly with the manufacturer of my equipment,” said Hunter. “They build the equipment, so they are the best at repairing and maintaining it. I have a mobile service tech in my area, so when I run into a problem, I know who to call for both my used and new equipment.”

An equipment auction is a great place to find used equipment at a low price, especially if the equipment is needed quickly. Contractors often have jobs requiring immediate needs for a piece of equipment or multiple pieces of equipment for a short period of time. Once the job is finished, purchasers often have the option of re-selling their trucks again at auction.

“If you are a new business owner with a limited budget and you want to make sure you’re making the right decision, consider working with a used equipment dealer,” said Tolley. “If you’re more experienced with equipment and know how to choose what’s right for you, an auction might have what you’re looking for.”

Auctions usually allow buyers to come the day before to touch, see, feel, and operate the trucks before they place their bids. Bring the correct people to help make the decision including operators and a mechanic, if you have one. Once a piece of equipment is purchased at auction, it’s yours, so come prepared with what you want and include the right people in your selection.

The used equipment market is extensive and changes every day, so finding what you need shouldn’t be a problem, but building in a timeline to your search helps.



How to Make Sound Equipment Decisions

Key Considerations for New and Used Truck Purchasing



a budget, know your needs, include the right people in your decision, find a trusted equipment partner and be patient, if you can.

“I never try to encourage one or the other – new or used,” said Senf. “Understanding a need and finding the best solution is always the best way to serve.”

About the author



Margaret Ann Walker is a member of the Marketing Communications Team at Altec Inc. based in Birmingham, Ala. Margaret Ann writes content for altec.com and contributes editorial for trade publications representing the markets Altec serves. Altec is a leading equipment and service provider for the electric utility, telecommunications, contractor, lights and signs, and tree care markets. The company provides products and services in more than 100 countries throughout the world.

“If you want four tool bins, but you can only find a truck with three, keep looking,” said Tolley. “A good dealer will be able to find it for you. If you have time on your side, you can afford to be picky with your truck.”

The more information you know about the truck including its usage, engine hours, and maintenance records, the more likely you are to make a sound investment. Trucks once belonging to an organization requiring regular upkeep and maintenance, like electric utilities and municipalities, usually make trustworthy purchases.

“We’ve had great experience with buying used trucks from municipalities,” said Hunter. “They perform standard service checks and are generally maintained very well.”

Bottom Line

Whether you decide to go the new or used equipment route, what’s most important is to get what you need. If you purchase a low mileage, low PTO truck at an auction, but it doesn’t meet your needs, it doesn’t matter what kind of deal you got on it. Establish

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How Utilities Leverage Data Analytics to Improve Efficiency and Enhance Operations

By Brian Crow PE

For most electric utilities, outage management is a top priority and concern. Take, for example, an electric utility located in the middle of the United States' infamous 'Tornado Alley.' After a series of devastating storms and tornados hit, the utility experienced serious damage to its transmission and distribution systems. However, by combining meter data with its outage management system, the utility was able to complete all repairs to its transmission and distribution systems within a month. In addition to repairing its transmission and distribution systems in record time, this type of system efficiency helped the utility enhance its customer service as well as prevent the potential for significant revenue loss.

Through proper data management and the use of data analytics, utilities can maximize the value of all the data that their sensors are providing them to draw insights, identify current or potential issues, and enhance operations.

There is no denying that we live in an age of information. What really matters, however, is what we do with this information. After all, the information on its own is just that – data. Utilities are inundated with data. As utilities adopt communications systems to improve their operations, these networks are delivering a growing volume of data from both the utility's infrastructure as well as external sources such as news and weather aggregators. As a result, utilities are struggling to manage and determine how to best use this surge of information. However, through the use of data analytics, utilities can now better manage this information and, ultimately, improve system efficiency.

There are three steps to optimizing the value of data analytics:

1. Collect the data
2. Analyze the information
3. Convert data into actionable insights

1. Collect the data

Communication networks provide data about power usage, the utility's infrastructure and even outages. While this information is useful, utilities are now asking, "What else can this information tell me? Is there an opportunity to use this information to improve system operations?" It benefits utilities to think about the other sources of data that they could be tapping into for a more comprehensive view of their system and operations.

Another key benefit is that data collection improves coordination, collapsing the walls between different utility departments. While

areas such as customer service may have had limited interaction with operations, for instance, data collection and analysis enable every department to see the big picture. The actions of one department often affect the entire utility and data analysis helps to showcase this. Through the use of data collection and data analysis, every department is able to work together to improve operations for the utility as a whole as well as benefit its customers.

Utilities and their customers are craving basic data and visualization such as charts, graphs and online dashboards. However, with data analytics solutions, utilities can quench this thirst and realize even greater value hidden within this information. If one department in a utility begins to implement data analytics, other departments will see the results, embrace it and the walls will come down.

However, while sensors on the communication network provide utilities with this data, collecting the information is just the first step.

2. Analyze the information

As the example above revealed, sharing data across departments within a utility can often address problems such as customer-related issues. While this type of data analysis is certainly useful to utilities, the real challenge lies in transforming this data into information that will benefit the utility, its customers and improve operational efficiency.

Utilities have two main options for how to analyze this data: they can either build a system in house or they can choose to source an outside data analytics vendor. There are certainly challenges and benefits with both options. When building a system internally, utilities have more control. More specifically, they have the complete ability to customize their data analytics system and do not have to determine the right vendor to partner with. On the other hand, this also poses certain challenges and obstacles, particularly for smaller utilities. For instance, a system might require buy-in across several departments within the organization as well as require numerous resources to maintain it. For smaller utilities, they might not have access to these resources, making this option less advantageous.

The second option is to work with an outside vendor. Data analytics is an evolving space; if a utility sources an outside vendor to supply and manage its data analytics system, software updates, for example, are seamless to implement. In addition, for many utilities and especially IOUs, they might have internal constraints to deal with.

How Utilities Leverage Data Analytics to Improve Efficiency and Enhance Operations

Very often, they cannot take the risks required to advance their own data analytics campaigns. Smaller utilities oftentimes do not have the resources necessary to build a system in-house so working with an outside vendor might be the best option in those situations.

Regardless of which option you choose, implementing data analytics allows utilities to continuously review, monitor and verify data. And the benefits are limitless. One major benefit is that utilities no longer need to continuously monitor data on their own. Data intelligence provides a series of routines to assure multiple checks and balances of the data. By using routines that verify data, utilities can expect to save both time and money.

This data intelligence also allows the utility to assign the appropriate action to automatically adjust any perceived discrepancies in the data. Utilities can pre-select responses and organizational tactics for different types of incoming information. This continuous and instant monitoring allows utilities to run more efficiently and better serve their customers. Data analytics can also immediately alert customers to certain occurrences or issues, helping improve response rates and enhance customer service. Customers can receive automated notifications and alerts at the very moment something is wrong. This type of automated notification can cut response rates and increase operational efficiencies, enhancing customer services as a result. In this age of technology, this rapid response is not only wanted but is expected by customers.

Given the ever-changing nature of the electric industry, data analytics provides flexibility through vast customization options to address the varying skill sets and needs within a particular utility. In addition, such agility allows for enhanced integration of complex networks. Through the use of data intelligence, utilities can solve nearly any data-related issue while also incorporating a sophisticated platform that can address more complex needs.

For utilities, another significant benefit of data analytics is revenue forecasting. With the ability to continuously bring in meter data every fifteen minutes, instead of just once a month or more, utilities can track their earnings in real time. Additional benefits include pulling customer information, better managing the business, segmenting sales data via customer classes, and estimating budgets to conserve costs and improve operations.

3. Convert the data into actionable insights

With the massive influx of data that utilities receive on a daily basis, a key part of data management is being able to sort through all of this information and pull in actionable insights. To truly benefit from such a large amount of data, utilities need to determine what data is required to best improve operations, reduce costs and enhance customer service.

One key example is a utility with a failed transformer. Prior to data analytics, the utility would automatically install a larger transformer, assuming that the previous transformer failed due to its load.

However, by using data analytics, the utility was able to determine that the transformer did not fail due to demand and was, in fact, too large for its system. Based on this data, the utility was able to replace the transformer with one at the appropriate size. Many utilities are even able to downsize their transformers on a broad scale. Data analytics can also enhance customer service for utilities. With data analytics, utilities can prevent customers from losing power during an unscheduled outage by predicting potential transformer failure. Transformers never fail at the time most beneficial to the utility to replace and often fail at the most expensive time of day and at the largest impact to the customer. Ultimately, the ability to gather and analyze this type of information can help utilities enhance their customer service, preventing customers from losing power by predicting transformer failure.

Reap the Benefits of Data

The combination of data management and analytics enables utilities to take a system-wide view of their operations, allowing them to run more efficiently and lower costs. It also allows utilities to better serve their customers by turning data into actual intelligence. With the right data analytics solution in place, utilities can manage their data and, most importantly, use this information to improve their utility and benefit the customer experience.

In addition to providing benefits to both the utility and its customers, data analytics provides environmental and societal benefits. Through the use of data analytics, utilities can not only monitor customer usage but also educate customers on their consumption. More specifically, data analytics can provide customers with regular alerts on their energy usage. By better informing customers about their energy consumption, they will become more aware of the amount of energy resources they use. This enables customers to be more knowledgeable about their consumption and can even promote customers to self-initiate conservation.

Ultimately, if utilities want to truly maximize the benefit of the data they are receiving from their sensors, data analytics is key. By collecting the data, analyzing its information and pulling actionable insights, utilities can gather information from grids, infrastructure and external sources to improve operations, reduce cost and inefficiencies and enhance customer service. Every utility has unique challenges, but the solution lies in data for many.

About the author



Brian is an 18-year utility industry veteran whose entire career has been focused on finding solutions to the challenges utilities face across their enterprise. Prior to joining Verdeeco, a Sensus company, Brian worked for the SAS National Utility Practice where he focused on providing utilities with analytic products such as load forecasting and energy trading risk measurement. Brian is a licensed Professional Engineer in the State of Georgia and received his BSAE degree from the University of Georgia.

Turning Grid Integration On its Head: Renewables are part of the solution

By Fliss Jones

DNV GL's global industry survey reveals a worrying split between the renewables sector and system operators, threatening the future deployment of clean energy. Unlocking the potential of wind and solar to operate more flexibly could help bridge the gap

"The days of 'monopolized' power are coming to an end. Get smarter or get out of the way." This was the frank ultimatum of a North American government employee to DNV GL's global survey of the energy industry. Earlier this year, more than 1,600 people from 71 countries provided their views on a scenario where renewables account for 70 percent of power-sector generation. The results shed light on the energy transition underway.

Change is coming

When asked how quickly the transition could be made to a high renewables system in a secure and affordable manner, 82 percent of respondents believed this could happen by 2050. Even bearing in mind a possible selective bias of optimism amongst those who chose to reply to the survey, this finding is notable.

But the survey revealed a worrying split between the renewables industry and grid players. Whereas renewables players see the opportunities of a high renewables scenario, system and network operators see the challenges. One employee of a distribution system operator went so far as to claim that there 'will be a revolt' due to the cost implications of renewables deployment.

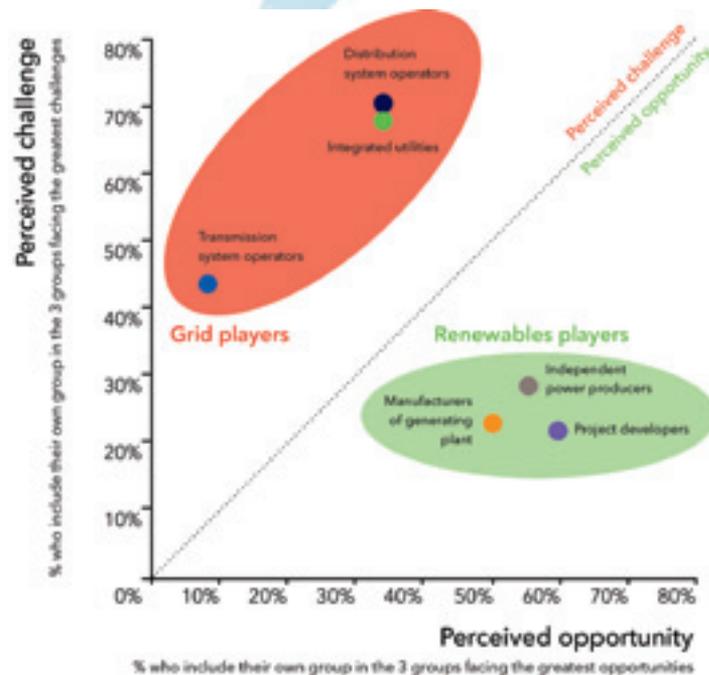


Figure 1: The renewables sector sees the opportunities, but system operators feel challenged.

Survey question: "The transition to a renewables-based electricity system (70 percent by generation) poses the greatest challenges/opportunities to which stakeholders in your markets(s) of interest? (Choose up to 3 answers)." Note that a subset of respondent groups are plotted.

Of course, renewables have technical characteristics that pose challenges to transmission and distribution operators. The two renewables technologies that are least expensive and are available in volume – wind and PV – are also both highly variable in electricity generation. Wind and PV projects are often fairly small and can be developed quickly – whereas building new grid infrastructure can be a lengthy process.

Bridging the Gap

The split between the renewables and grid players is concerning because a high renewables future can only be achieved with system and network operators on board. It needs to be addressed.

Partly the solution lies in interconnection, demand response and storage. But it's time to realize that far from just being 'a problem' for the grid, renewables can also be part of the solution. It's rarely recognized that, with the exception of providing energy on demand, wind – and to some extent solar – can do anything a network operator wants, and often faster or more accurately than conventional generation can achieve.

Renewables have the potential to provide ancillary services to support the reliable operation of the transmission system. For instance, wind projects can provide synthetic inertia, whereby they increase power output for a matter of seconds during a change in grid frequency. Siting and plant design improvements can also provide substantial grid benefit, often at limited cost.

Technology is not the limiting factor. Although renewables' flexibility potential is significant, project developers and operators are rarely given a reason to use it. The trick, though far from simple, is to structure markets and regulation such that project benefit is aligned with grid benefit.

As our North American respondent rightly highlights, we need to "get smarter." We need to go beyond old metrics and rules, which prevent renewables from being flexible, to help bridge the gap between renewables players and grid players.

It's time to turn the renewables grid integration debate on its head. Renewables are not something to be 'integrated' into status quo grid arrangements. We need to rethink the electricity system itself, and the contribution of renewables towards it. We need to go beyond old metrics and old rules – beyond integration.

About the author



Felicity ("Fliss") Jones, DNV GL senior consultant has lived and worked in the U.K., Singapore and Norway, leading strategy and policy projects in renewables.



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Transmission and Substation Asset Engineering: Evolution of Reliability Improvement Projects

By Neal Rich

Engineering Design Drivers for Securing the Future Integrity of the Grid

Even though there is plenty of variation in our grid reliability improvement efforts, the latest project designs for transmission and substation improvements can be split into two main categories:

1. Designing to meet more complex standard operating conditions
2. Designing to harden and protect substations from rare events, such as more severe weather and coordinated attacks.

Of course there is cross-over between these two categories. Where it makes sense, we can take into account the more complex standard operating conditions while designing to harden substations, and can include some hardening/protection from rare events in some elements of new “standard” designs.

These days, to protect strategic critical assets utilities and commercial/industrial clients often want designers to protect assets against more failure modes. A key balancing act is required here, since experience and good teamwork are needed to help the project team work toward the most cost-effective ways to go forward with these types of projects.

What Has Changed? What is the Same?

For many years, electric utility design personnel and engineering project managers have been working to get the most out of aging transmission and substation assets while making sure grid reliability improvement efforts pass two typical tests: are they prudent, and are they cost effective?

Many utilities have done a great deal to ensure top-notch staffing for their in-house design departments, and try to equip engineers with the best available tools. This has not changed. And as always, the emphasis on achieving a successful project has stayed the same and is still measured based on quality, stakeholder/customer satisfaction, as well as meeting key budgetary, and project timing goals.

So what is different now? A great deal is different! A common theme across the trends highlighted below is that utilities seek to leverage the strength of experienced engineering personnel. And they try to do so through a culture of trusted and proven relationships, whether the work is performed 100% in-house or through a mix of engineering

firms and associated third-party contractors.

1. In terms of what is different, first, from the point of view of standard operating parameters, the grid is being improved to make it more flexible in order to ensure reliability of power supply in the face of more complex power flows. Grid complexity is increasing due to numerous factors, including the ongoing incorporation of more renewables and distributed energy resources, optimizing O&M across fleets of aging assets, as well as increases in the need for more reliable service. When we talk about more reliable service, we are not just referring to key types of critical customers of the past (e.g. hospitals) nor just to the fact that customers have become more dependent on reliable power (whether commercial, industrial, or residential). Instead, we are also referring to the need for uninterrupted electric service to the data centers and server farms that are the backbone of the web-based digital economy. Data centers in the U.S. now make up more than 6% of electric demand, and that number is growing rapidly.
2. New substation and transmission design work is now addressing the high-profile “unusual” conditions. These include optimally hardening the grid against major storm events such as Hurricane Sandy, as well as terrorist attacks (e.g. the PGE Metcalf substation sniper attack).
3. Some utilities do not have all of the in-house engineering design staff necessary to get it all done – whether due to the sheer volume of work, as a result of specialized design or electrical study needs not available in-house, workload balancing, ‘brain-drain’ based retirements, or simply due to the cost-savings associated with utilization of less in-house staff.

It is an exciting and daunting time for the engineering designers, project managers, and industry executives, with many utilities deploying a dynamic mix of in-house and third-party engineering and project management resources. As a result, executives responsible for substation engineering, design, and project management personnel have a lot on their plate in their efforts to optimally serve their customers, stakeholders, and regulators. They have the added challenge of meeting all relevant engineering and design standards as well as safety requirements.



Themes across Range of Projects

While it may sound paradoxical to talk about projects being “typically unique,” there is a grain of truth to it. But a common theme for many substation projects is that fully optimized designs should be engineered to be adaptable. This includes practical aspects related to supply chain and timely delivery of critical parts, and scaffolding. Also the ease with which the construction work can be carried out must be considered, as well as ensuring protection and control designs are done with an eye toward the relative ease with which field personnel can be re-trained if there are any operational impacts due to changes in switching and isolation procedures. And good designs should be able to accommodate foreseeable changes in technologies.

Experienced project managers should be ready to address a wide range of options in determining how to economically and operationally optimize control and physical system efficiency and reliability. The ‘adaptability theme’ cuts across a wide range of work situations. It applies, for example, whether the project involves one or more of the following:

- Performing substation related protection and control system improvements for a large electric utility
- Adding redundant feeds and communications systems to critical auxiliaries of an independently owned and operated generating facility
- A combination of specialized cold load pickup engineering studies and diverse contingencies’ scenario analyses, culminating in recommendations and subsequent engineering project work to improve an ISO’s black start capabilities

The balancing between engineering and economic considerations can lead to a client being given options to keep some of the existing control systems if the modifications permit the desired reliability levels to be achieved, rather than always replacing the entire control system.

Whether improvements in a substation’s hardening are being done for a utility or an ISO, or for a customer-side resource (such as a campus, hospital, school or industrial facility), there are benefits to be considered in terms of leveraging the hardening work in order to provide additional reliability benefits beyond the immediate vulnerability that is being addressed.

Mission critical assets now must address higher complexity levels of systems, whether serving needs requiring more reliable service, or ensuring quicker restoration of service in response to grid disturbances.

The ‘People Factor’ and Successful Substation Reliability Improvement Projects

Many utilities, from large investor-owned utilities to smaller utilities, are seeking to improve their relationships and develop better relationships with contractors who perform critical and necessary engineering and design jobs.

As experience has shown, it is important to have strong and trusting relationships between the people who are working on these critical infrastructure projects. This may seem like an overly simplistic statement either due to a view that it has always been true, or due to a belief that our utilization of various software and communication tools to create ‘virtual teams’ has made trusting personal interactions less important. On both counts, the opposite is true because the increased complexity we face makes it more important now than ever before to have the best possible interpersonal communications and relationships.

As engineers, we love having the latest and greatest technological tools and we are not ashamed to highlight them. But no matter how sophisticated our technical tools may be, we should always remember that having better tools makes trusting relationships and good communication skills more important, not less important. Why? Because quality resides in how people use tools, and in the types of questions they ask. In fact, the stronger our technological tools become, the more important it is that we keep our thinking muscles well exercised, since otherwise over-reliance on our tools may cause an increased danger of a ‘bad data in / bad results out’ scenario.

Good relationships facilitate better exchanges of information between engineers and project team personnel, yielding better “*what if?*” questions to be asked.

Consider complexities associated with understanding all of the key elements of the protection control logic of a substation design project. During the project, by creating an environment of trust, it ensures that engineers will contact our expert personnel at the slightest hint of a question or problem and communicate about it. Why? Because without the trusting relationship it becomes more likely that the less experienced staff may be reluctant to ask an important question.

A great deal of creativity and leveraging of past experiences is involved in developing the most efficient designs possible, while minimizing clients installed and lifecycle costs and ensuring ease of operation, flexibility, and reliability. It takes a high level of broad multi-discipline experience and support.

Early in the setting up of such projects, it is important that the project manager and engineering design staff uncover client needs beyond what is asked for, to ensure options are put on the table that can bring the greatest possible value. This ethic should continue as part of the ongoing processes for a project, by having regular project covers calls with clients and to have the frequency of those calls vary as a function of project complexity. This helps to ensure step-by-step quality control, along with assigning individuals based on experience levels, so as to optimize value delivery by not over or understaffing with all the associated costs and issues in either case.

Who Polices the Police?

Increasingly, design engineers are being called upon to reliably address unique engineering/design needs while also applying the most reliable, high quality standards-based designs. But with all this increased importance on reliability, one may ask 'Who polices the police?'

For example, hardening the transformer bank at a site against attack by increasing electrical redundancy and enabling online hot-swappable transfers, does the designer also add redundancy and hardening of designs for the associated communications and control systems, so that no earlier single point of vulnerability can still lead to a system failure?

Our best answer to this type of 'who polices the police?' question is that the best way to improve operations and work quality is through reliance on proven relationships of trust and teamwork.

One of the cultural norms for our engineering design and project management work in our substation client relationships involves ensuring that we provide a single point of contact within our group—even though multiple team members may serve in various roles of design leader, support engineer, quality assurance, or quality control.

The person who performs a checking role in a particular design or study area should only be assigned to that role if they have done that type of work multiple times. Nobody should be assigned as the checker for an area where they are involved with something for the first time.

You may ask, isn't it a bit of a contradiction to suggest that the checker have experience in the area of engineering involved while at the same time you're saying that more and more of these types of projects are of a custom character? How do you have experience if it's custom? The answer is that it is not a contradiction, since such custom projects fall into patterns and have key things in common with one another. Another very important common factor between different types of custom projects is experience with the types of problems and questions that come up and need to be addressed.

Unusual protection and control schemes are often included in the more complex engineering designs, and as a result, strong and trusting personal relationships between project personnel, and

the ability to communicate in a very nuanced fashion is critical. Excellent documentation and technical reporting by engineering staff cannot provide the desired foundation for reliable project success, unless the personnel that are exchanging these ideas interact well. A high trust level is insurance against lack of communication, and it encourages people to ask for clarification if something does not make sense to them. Good project managers should encourage staff to communicate with expert personnel at the slightest hint of a question or potential problem.

Conclusion

Substations play a key role in ensuring the reliability of our electric grid. Regarding reliability-related concerns, we have some lessons to learn from ancient Rome.



First, we should not overbuild our infrastructure. As physicist Dr. Neil deGrasse Tyson has pointed out, if a civilization's infrastructure outlasts it by 2000 years, might it not have been a bit over-built? On a more serious note, we also should not under-engineer our infrastructure. In spite of Dr. Tyson's remark, in reality very little redundancy was built into the Roman aqueduct system. All the barbarians needed to do was knock down one arch on an aqueduct, and the entire run of that line was rendered useless.

Regarding reliability, also instructive is an archaeologist's recently-discovered ancient Roman joke:

A man runs into an acquaintance and says "I was told you were dead" and gets the reply "well, you can see I am still alive." The first man disagrees, saying "the man who told me you were dead is much more reliable than you."

Moral of the story? When we set out to improve the reliability of something, let's make sure we always put more reliable, not less reliable, links in the chain.



About the Author

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Pioneering Innovation While Keeping the Lights On

By Michele Morgan

Ours is an era of unstructured information. The data we seek to manage, analyze and interpret value from is available to us on a scale previously unfathomable – creating both opportunities and challenges for CIOs in every industry. If we can manage that influx of data and coordinate the disparate systems that generate it, we can achieve a holistic, real-time view of operations and extract meaningful insights that can boost the bottom line. If not, we'll find ourselves drowning in data and lagging behind in a relentlessly progressive, high-tech environment.

CIO Challenge #1: Seeking a real-time view of global operations – from ship to shore

When I worked for an oil and gas transport company generating \$3 billion in revenue annually from a fleet of over 150 oil and liquefied natural gas tankers operating around the world, keeping close tabs on those vessels from shore was paramount. A minor mechanical failure or lost data transmission could cost up to \$35,000 a day in downtime, and safety breaches could be fatal. We relied on manual maintenance reports communicated from the vessels via slow and costly satellite transmissions, then looked to on-shore personnel to make sense of the data. We were continually in search of a system or tool that could provide a more comprehensive, on-shore view of our fleet in real time. If we knew more about what was happening on our vessels, and had the ability to compare each vessel against the others, it would have been enormously powerful. We could have recognized patterns and ultimately predicted maintenance and safety issues before they arose, and that would have resulted in cost-savings for the business.

The latest tanker technology – like many industries that involve monitoring field devices remotely – has the capacity to relay detailed information from sensors or devices on the vessel directly back to shore instantaneously. But capturing all that data is just the first half of the problem. Next, you need to sift through millions or even billions of data points to identify meaningful and actionable insights – and it is this business challenge that is common across so many industries. Regardless of where you're collecting data from, the key is to look for a software solution that can serve as a virtual operator, meaning it can sift through the 'noise' for you and alert you only to 'actionable' issues. It should also be capable of 'predictive operations,' recognizing patterns (for example, particular readings on devices X

and Y may precipitate a mechanical failure of device Z) so that you can mitigate issues proactively.

CIO Challenge #2: Coordinating disparate systems – in search of a single source of truth

Moving into the finance industry as the CIO for a credit union in British Columbia, Canada, with over \$6 billion in assets, I landed in an environment rife with mergers and partnerships. Credit unions everywhere were joining forces, which meant they needed to be able to access members' account information via each other's systems. The problem? Each credit union operated its own system, and pulling info from someone else's system required complex and often cumbersome integration tools. Moreover, implementing such an integration tool was to be avoided at all costs. It could take two to three years, and drive away thousands of frustrated members. This also focused IT resources on playing catch-up behind the scenes following a merger or partnership, rather than on innovation and progress in a rapidly advancing industry threatened by market-disrupting products like PayPal and Google Wallet.

Our goal was specific: to be able to quickly and seamlessly pull clean data from multiple systems to gain a 360-degree view of our customers and thereby target our products and services to them. But that goal was hindered by an underlying challenge I'd faced in every other industry I'd worked in: the integral need to coordinate disparate operations systems. To do so (in any context) requires a multilingual software program that can read all coding languages, and is thus able to query and retrieve info from any operating system directly without having to reconfigure the operating systems themselves. This is not only faster and more cost-effective to set up, but it helps to identify the existence and source of bad data, so you're able to make better decisions based on reliable and more easily accessible information.

CIO Challenge #3: A simple interface anyone can use – catering to the business user

It wasn't until I reached the utility sector, where I was tasked with choosing an integration tool for a massive smart metering project at BC Hydro, British Columbia's primary utility company, that I saw the solutions I'd been looking for in motion.

Pioneering Innovation While Keeping the Lights On

I was faced with the same challenges as before: needing a real-time, contextual view of my 'fleet' (two million smart meters in the field) and integrating disparate systems (work order routing, asset management, etc.). And in fact, utilities have pioneered machine intelligence technology for the Industrial Internet with the potential to benefit from capturing, analyzing and interpreting data from any kind of sensor-equipped field device. But this time I had the added challenge of needing something engineered for business users rather than IT staff and other technical experts. With the smart meter rollout being new to the whole company, we needed a tool that was easy to use and quick to learn so that non-technical business users could leverage its full potential with a minimal learning curve.

No matter what type of data or devices you're looking to manage, a simple interface is key. It should take no more than a single day's training to learn to use it to its full capacity, and everyone from the most junior operations staffer to the company CEO should be able to use plain English query language (much like what you'd type into Google) to retrieve valuable and actionable data.

The balancing act: Championing progress while maintaining security and stability of networks

As CIOs, we are destined to perform an eternal balancing act: championing progress and pioneering innovative solutions in a risk-adverse and change-resistant environment. We must stay ahead of the curve, yet, above all, keep the lights on and the technology stable.

Rest assured that this is possible – *if* you know what to look for in a software solution.

Whether or not it has already been applied to your industry, machine intelligence technology for the Industrial Internet is in use on a daily basis in enterprises around the world, and can be adapted to almost any application. Above all, look for a technology platform engineered to solve a business problem, rather than a technical problem – one that allows you to manage and analyze data from disparate systems at scale and extract meaningful insights, all in real time.



ABOUT THE AUTHOR

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THE BIGGER PICTURE

BY DON HALLGREN AND ROSS SHAICH



System Testing for Outage Management and Distribution Management Systems – Critical Success Factors

Outage Management and Distribution Management Systems are mission critical applications and they must be available, responsive, accurate, and reliable at all times. Proper quality assurance and testing are critical success factors for implementing these systems.

The modern grid is growing in sophistication and utilities face many challenges that dramatically increase the complexity of operating and managing the electric distribution system. Customers have increasingly high expectations for service reliability and electric power quality. Large amounts of data are made available by smart grid technologies. Utilization of distributed energy resources (DER) and Microgrids are increasingly common in operation of distribution networks. In response, Outage Management Systems (OMS) and Distribution Management Systems (DMS) are becoming more complex and robust. Advanced Distribution Management Systems (ADMS) are also emerging as a single integrated platform that supports the full suite of distribution management and optimization.

There is a great deal of activity on the OMS and DMS fronts. According to a recent report, global utility OMS spending is expected to total nearly \$11.8 billion from 2014 to 2023¹ while global ADMS revenue is expected to grow from \$681.1 million in 2015 to \$3.3 billion in 2024.² It is vital for utilities to understand and use good testing methodology to maximize the benefits from these investments. Strong methodology and execution can be the difference between a successful investment versus ongoing problems, decreased confidence, and additional money and time spent in support of these applications post go-live.

High demands are placed on these mission critical applications, not just during abnormal conditions (e.g., storms), but also under normal (non-storm) conditions. During severe storms, the OMS/DMS systems are critical for quick and cost effective restorations. A utility cannot afford sluggish performance, inaccurate / outdated information, or system failures. A different set of challenges exist during non-storm conditions. For example, this is the time for planned switching activities, where crew safety is of the utmost importance. The information must be timely and reliable, otherwise faulty switching, grounding, and tagging information could jeopardize repair crew safety.

During an OMS upgrade, one of the authors was in an operations center when a crew member in the field went down in a high voltage area. The OMS alerted operators, emergency personnel were notified, and additional crews were dispatched using the OMS. Everything turned out ok – in this instance, the OMS helped save a life.

Testing is key to achieving a properly functioning system that users are confident in. OMS/DMS system testing needs to be well planned and executed whether it is for a full implementation, an upgrade, adding or updating an integration, or installing a maintenance patch. Testing verifies whether:

- The system and environment are robust enough to stand up to stress from heavy load
- Information maps correctly to displays
- Correct data field mapping exists, connecting the data location in the source system (e.g., GIS) to where it is used in the OMS/DMS/ADMS.



- The data contained in the source system is correct (Bad data in the GIS will show erroneous information in the OMS/DMS/ADMS, even with proper mapping)
- Outages predict to reasonable devices at the proper speeds
- Appropriate warning and violation notifications are produced
- The general appearance of the model (i.e. electric, geographic, background) is acceptable
- The system fully supports the end-to-end business processes
- Application is responsive under high stress and heavy use
- All integration flows properly function and are responsive
- High availability / failover works as expected
- Advance applications complete and produce results within the expected time

Keeping the following Critical Success Factors (CSF) in mind will help utilities to develop and execute a well-planned testing methodology that helps prevent (or identify early) as many defects as possible. These CSFs are based on many years of experience testing OMS/DMS/ADMS and the lessons-learned. It attempts to strike a balance between excessive (wasteful) and insufficient (missed defects) testing.

CSF #1: Create Testable Requirements

Some projects treat requirements writing only as a design input and forget their importance to testing. Requirement identification/writing is where testing should begin. Requirements should be tightly coupled to testing (i.e. requirement based testing).

When defining requirements, use short, concise and testable statements. Avoid multi-sentence and run-on requirements. Requirement statements containing multiple thoughts should be separated into multiple requirements. A single action with a single result makes the best testable requirement.

When defining a requirement, ask yourself, “How can this be tested?” The reason being that the goal of testing is to verify the requirement. If the requirement isn’t testable, then it probably shouldn’t be called requirement and should be removed. Removal of untestable requirements is just as important as well-written testable requirements. Vagueness in requirements can lead you astray. Some examples of non-testable vague requirement statements are:

- The system shall group outages appropriately (too subjective)
- The system shall support all the users needed in a storm (exactly how many is all)
- The model in the viewer shall look presentable (too subjective)

Testable requirements have specific measures that can be verified, for example:

- The system shall group 3 transformer outages of the same phase to the upstream device
- The system shall support 50 concurrent users
- Devices in the model shall have and support all the attributes defined in the device attribute specifications document

OMS/DMS/ADMS are complex systems, so requirement flaws do occur. Examples of flaws include inexact, broadly written, or totally missing requirements. Low quality or missing requirements directly impact the project and result in excessive questions during test creation, important functionality going untested, and insufficient time for completing test execution. Insufficient requirements can lead to extended ad-hoc testing. Testers (especially end users) expect to verify whether functionalities work as expected/desired even in the absence of a specific test case for it. It is important to perform the necessary testing, even if it is ad-hoc. Poor or missing requirements can result in uncertainty, misinterpretation, rework, test case defects, and unplanned testing added late in the testing cycle. Ultimately, as a consequence of inadequate requirements, the project schedule slips.

The requirements creation process can help avoid or find defects early-on in the project. It can help identify product limitations, discover defects in the core system, and – by thoroughly working through the business processes – it can help identify or confirm what functionalities and information are required. The earlier a defect is found, the less expensive it is to resolve.

Finding Defects Early Saves Time and Money

- Defects found and resolved before the start of a formal test cycle help avoid failed test cases. Sometimes one defect would cause multiple test failures, which would necessitate significant time retesting each failed test case to verify the fix.
- Avoids Executive worries (and the questions and the meetings). A high severity defect found during requirements definition, test case design, or at the start of testing cycle, rarely draws attention or require explanation like the same defect would if it were found later in testing.
- Avoids repeating the system update process (code fix, build, deploy, re-test)
- Test Once (avoids multiple environments, test case fixing, re-testing)



CSF #2: Freeze Requirements

Adding or changing requirements, especially in complex systems like OMS/DMS/ADMS, risks system stability and adds duration to testing and ultimately the project. These types of changes typically occur at the most inopportune time, when you are about to exit testing. Adding or changing requirements too late in the game results in having new tests to create/execute, invalidating/wasting earlier testing, and functionality that was tested before and passed now has defects. Those late changes often have been rushed into the system and have had more abbreviated unit and regression testing, which increases the risk of new defects.

Reality is that requirements do change throughout the lifecycle of a project. Good change management is the solution for this dilemma. Establish a requirement freeze and stick to it. If change comes in during testing, consider deferring the change and then plan it into a future release when the change can be made more safely.

CSF #3: Define the Rules

The testing methodology should be documented in a functional test plan. The plan defines the rules of the testing engagement including reviews, entrance criteria, test case development (including style sheet), test execution schedule, defect writing and triage and tracking, fix promotion, and exit criteria.

Before delving into the minutia of testing, let's define a few testing terms (Table A).

Table A – Testing Terminology Definitions

Term	Definition
Test Case	The standard term to use in reference to the test. A test case contains a series of test steps.
Test Plan	A document created to plan out the test phase. It outlines the approach taken from the planning stage to execution and on through closure of the testing phase of the project. This is a detailed plan, not merely a project work breakdown.
Test Script	A short program or executable file used in automated testing.
Test Step	The simplest instruction of a test containing a description of the action to take and the action's expected result.

Reviews

Identify what needs to be reviewed and by whom. A solid requirement review helps establish better frozen requirements. The review list could include: requirements, test cases, and defects. The list of reviewers could include business analysts, subject matter experts (SME), operators, project managers, and testers.

Entrance Criteria

Entrance criteria defines what needs to be done prior to starting the test execution phase. This list could include a reviewed and signed off test plan, reviewed and approved test cases, approved requirements, GIS/customer/estimated restoration data readiness, and hardware/software components to be installed on the target test environments.

Test Case Development

Test case development defines the step-by-step procedure for what to test and what the expected results of the test should be. Since this is the most time consuming part of testing, some definition and standardization is warranted here. Who's going to do the test execution and who's going to execute the tests influences test development time. If the consumer of your tests is more than just testing/management, such as test automation or training, test development will take longer (sometimes much longer). It's important to be clear on who's going to use your testing efforts.

Here are some tips to creating quicker, clearer test cases:

1. Write test cases using the active voice. Avoid 'should', e.g. You should have seen an RO symbol... Instead write: An RO symbol is displayed. The shorter and more succinct the better.
2. Avoid using future tense. Avoid 'will be', e.g. do not say: You will see an RO symbol. At that point the tester already 'sees' an RO symbol. Instead write: An RO symbol appears on the Viewer.
3. Use different test data for each test case. In an OMS/DMS/ADMS you'll likely have several hundred test cases and multiple testers executing test cases at the same time. Having different test data minimizes/eliminates potential collisions with other testers. Mitigating the impacts of testers working in the same area avoids unnecessary bugs or the invalidating a test execution.
4. Contain one entire function per step. This can include multiple sub-steps to accomplish a function. The idea here is accomplish one basic thing per test step. For example:
 - In the Viewer, Press the Search Icon,
 - Enter into the 'Device': xf_123456, then
 - Press Search



- This could be written as three steps, but the goal is to load the map containing xf_123456 in the Viewer application. Since a step like this might be executed many times, it is less tedious to both the test writer and tester if it is written as a single step.
5. Use a standard test case style sheet for designing test cases (see Appendix A). Standardized styles helps establish and enforce consistency.
 6. Test steps must have enough punctuation and spacing so that the intent of the step is clear, but avoid overly-strict adherence to every grammatical rule. Excessive attention to grammar rules extends test writing time when that time that could be better spent validating the software.

Test Execution Schedule

Test execution schedule defines what is to be tested, who is going to be doing the testing, and when.

Defect Writing and Triage

Defect writing and triage defines how a defect is written, defines defect severity levels, and how defects are processed. The goal is to resolve and close defects as quickly as possible. This goal fails if a defect is poorly written or the processing is too slow (and cumbersome).

Fix Promotion

Fix promotion defines the process of how fixes are promoted from the development system into test environments and then on to production. It is important for retesting and defect closure to know: 1) what results are expected, 2) when is it available, 3) how it gets deployed, and 4) in which environments to deploy it. Having this process defined builds confidence in the fix deployments and provides the defect list to assign for re-test.

Exit Criteria

Exit criteria define what needs to be accomplished to allow exiting the test execution phase. It simply answers the question “How do we know when we are done?” This includes the required pass rate of the test set (usually 100%), acceptable number for each defect severity level, and if/how exceptions or workarounds are to be documented and signed off.

CSF #4: Use Business and Non-business Teams Appropriately

Establish a team of diverse, motivated and collaborative testers. The testers need to bring different perspectives, experiences, and agendas. A pure tester will validate end cases and boundary conditions where operators bring real life process experience to look at factors not specifically written into the test case. Both kinds of team members are needed and they will both find defects. The critical objective is to find important defects as fast as possible.

Finding time for business users (operators) to test can be an issue. Address this challenge by testing during off season (low storm), and have enough business users available to not affect the daily operations while participating in testing.

CSF #5: Keep It Simple and Lean

There is a lot to test on an OMS/DMS/ADMS. There is a fine line between being thorough vs. ‘over-processing.’ Due to the criticality of outage and distribution management, it is important to fully test the system, but at the same time, it may not be necessary to formally test every exit button in every configuration of every tool. For certain functions, a sufficient sample of tests will fulfil the testing need.

Over-processing testing has multiple downsides. Some of these include more test cases to create and maintain, more calendar duration to execute them all, more results to track, mental exhaustion, and ultimately, increased cost to the project.

Maintenance patch testing also has the potential for over-processing. The system needs to keep current, yet change induces instability. Those maintenance patches often contain critical fixes to the system. Having those fixes could prevent future system down times encountered at inopportune times. The tester’s job is to test these patches well enough to ensure system stability.

Within a test case, keep test steps as simple as possible. Some steps test basic core functionalities that will be performed thousands of times during a test cycle. In a test case if you can turn 5 low-level test steps into 1 appropriately sized step, then do it. The benefits include simplifying it for the tester to read and follow, avoiding mental fatigue, and allowing greater focus on the important aspects of the test.

CSF #6: Diversify your Testing

The depth of data combined with diverse functional paths, makes OMS/DMS/ADMS testing unique compared to other utility power applications. An operator can follow their usual path, to perform a function – such as opening a fuse – using menus, dropdowns and/or popup windows. This same function could also be performed using power keys. Testers need to be instructed not to do something the same way every time (i.e. menu selections vs. icon clicks, double clicking vs. selecting and clicking an OK button, right-click menus). It is important to test the system in various ways. Test coverage is increased by testing the various different paths to perform a function.



Model data is another area that needs diversity in testing. Different parts of the model may react differently than others. Some regions may have feeders with a unique device type or more dense population. Certain regions have older devices, sometimes with obsolete data or devices. Other regions will be newer and uncluttered. It is important that testing incorporates this data diversity. Data issues that exist are further compounded by the current trend of merging utility companies. While it's impractical, if not impossible, to test every data point, testing on several diverse areas will provide reasonable test coverage.

Figure 1 shows how diversity increases testing coverage. In OMS/DMS/ADMS, the data axis is multiplied by each component.

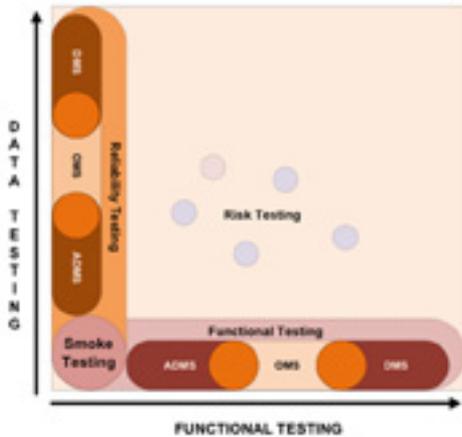


Figure 1 – Diversity and Test Coverage

CSF #7: Decide Where to Spend the Most Effort

When planning what to test, determine what needs the most attention. Your time is limited and there are many features to test, so take the time to determine where your efforts will be best spent. Recommended focus areas include:

- Overall system performance and stability
- Areas that would risk injury or death, should there be defects
- Features that must produce accurate results
- Features that must produce reliable results
- Features that are new to the product or your implementation
- Features that are unique to your implementation
- Features that have historically been problematic
- Highly configured features

When deciding where to place attention, consider new features that have not had time to mature (possible undiscovered design flaws) and functionalities that are not used by many (or any) other utilities and thus do not have the advantage of being tested during the software manufacturer's release testing.

Finally, performance is always worthy of significant attention. Under the stress of storms, the risk is that performance degrades or the system and/or interfaces crash. At one utility, insufficient performance testing led to such poor production performance that they discussed turning off their OMS during storms, taking away what this tool was designed to do; help resolve outages. Eliminating sluggishness and unreliability is critical to success. Performance related issues can be caused by software flaws, by data, misconfiguration, or the computing environment (i.e. inadequate hardware, database tuning, network issues). Make a plan that includes testing with the full electrical model, all interfaces, high numbers of users, high numbers of callers, and high levels of system activity. Be aware that every performance issue is not necessarily caused by a software bug. Other potential sources of performance issues include the network infrastructure, the database, and server operating system. If testing identifies performance issues, then it is not uncommon for any of these IT disciplines be used to diagnose the issue.

SUMMARY

Testing an OMS/DMS/ADMS presents a unique set of challenges. The requirements phase of such projects too frequently is lacking or omitted altogether in order to save time. Requirements are critical not only for identifying how the system should function, but also as the starting point for testing. Structuring requirements so that they're testable reduces defects and saves time. Controlling change to those requirements mitigates many risks, especially when change happens deep into testing. With great amounts of data and multiple paths to perform actions, diversity in the test cases and the test team are imperative. There is a limit to how much testing can be done, so decide on priorities and stick to them. Following a well-planned testing methodology results in protecting the value of the financial investment

APPENDIX A - TEST CASE STYLE SHEET

The following sample convention standardizes the 'common test language' within a test case, improving the test execution. This also provides consistent documentation and increases test clarity to the test executer. The convention is designed with HP QC/ALM testing tools in mind.



Test Case Style Sheet – Sample Conventions

Convention	Summary	Detailed Description
PreCondition	Pre-condition step	A special test step that documents conditions that must be met before executing the test case.
PostCondition	Post-condition step	A special test step that documents conditions that restore system to the original state upon completing the test case.
Tool Name	Tool Name	Tool name should start with a capital letter
[sample]	Button	A word encased in [] brackets represents a button. E.g. [Cancel]
<sample>	Data to Enter	A word encased in <> less than/greater than represents data to enter into a field. E.g. <Don't let this person in>.
Sample	Web Link	A blue underlined word represents a web link. E.g. View all positions and access levels or Sharepoint.utilitycompany.com/testing_docs/data_file.doc
Magenta	Uncertainty	Any wording in the magenta color means the author is uncertain about the statement to be revised later.
"Backspace"	Key on keyboard	A word encased in "" double quotes represents keys on the keyboard. E.g. "M", "Backspace"
{sample}	Error message	A word encased in {} braces represents an error message. E.g. {Internal Error}
CLICK	on button and link	The keyword CLICK represents an action to click on a button or link.
PRESS	on keyboard keys	The keyword PRESS represents an action to press on keyboard keys.
CHECK	Checkboxes and radio buttons	The keyword CHECK represents an action to select the checkboxes or radio buttons.
ENTER	Text in to a field	The keyword ENTER represents an action to enter text into a field.
SELECT	From a drop down list	The keyword SELECT represents an action to select an item from a drop down list.
Selection Sub selection	A " " (pipe) symbol	The separation character to indicate cascading menu selections.

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SECURITY SESSIONS

BY DEAN MUSSEY PE

Municipal Utility Takes Action to Offset Steep Price Increases in New England

Municipal electric utilities in New England face significant energy cost increases in the coming years due to the retirement of older generation plants and the impact that shifts in the sourcing of generation will have on transmission patterns. Municipal utilities can mitigate the impact of these increases by reducing the amount of energy used across their service areas during targeted high-value periods, including critical peak hours. To accomplish this goal, municipal utilities must be able to do three things:

1. Predict when high value hours will occur on the grid
2. Motivate and empower large energy users in their service areas to reduce energy usage and, most importantly
3. Do all of this without transferring the customer relationship to a third party vendor

The following discusses these issues in greater detail and describes how one municipal utility in New England is meeting the challenge by employing a strategy that relies on Commercial and Industrial (C&I) Distributed Energy Resources (DERs) and a Distributed Energy Resource Management System (DERMS) that could save millions of dollars per year.

New England Generation Plant Retirements

EPA restrictions and marginal economics have caused a significant number of generation plants to announce retirements in New England. This, in turn, is driving cost increases in the coming years.

According to a published report¹, *More than 4,000 MW of primarily older, less efficient, and higher-emitting resources have already left the market, with another 3,500 MW exiting by 2018.* Another 6,000 MW's of capacity is sourced from plants that will be at least 40 years old by 2020 and designated at risk. Notable exits cited by the report include:

- Brayton Point Station (1,535 MW from oil and coal)
- Mount Tom Station (143 MW from coal)
- Norwalk Harbor Station (342 MW from oil)
- Salem Harbor Station (749 MW from oil and coal)
- Vermont Yankee Station (604 MW from nuclear power)

These exits will make it more expensive for municipal utilities to acquire the energy needed to service their customers. The table below shows the impact these retirements are having on key components of the region's overall energy costs.

ISO-NE Estimated Transmission and Capacity Rates²
\$/MW-Year

ISO-NE Markets	2015-2016	2016-2017	2017-2018	2018-2019
Transmission Costs	\$98,249	\$104,659	\$110,559	\$117,129
Northeastern MA (NEMA)	\$42,768	\$77,160	\$180,000	\$114,600
Southeastern MA (SEMA)	\$42,768	\$37,800	79,200	\$132,960 ³
Rest of Pool (ROP) ⁴	\$42,768	\$37,800	\$79,920	\$114,600

Since most municipal customers are on a blended rate, they will not see increases in the specific cost drivers, but feel their impact in the form of overall energy cost increases.

As the table above indicates, all regions will see significant increases, but ISO-NE customers in the Northeastern Massachusetts (NEMA) region will see capacity rates increase more than four-fold to \$180,000 MW-Year by 2017/2018.

Understanding the Underlying Cost Drivers

High value hours occur when prices increase and charges related to critical peaks are assessed. The price increases are self-explanatory, but the relationship between critical peaks and energy costs merits some additional explanation.

ISOs and RTOs have an obligation to reliably meet their regions' energy needs, even during the highest periods of energy use. To plan for these periods, power pools need to determine 'how high is high' when it comes to the need for electricity. The exact calculation varies across ISOs/RTOs but the logic is similar. When the system-wide need for electricity is at its peak, the ISO determines how much each energy provider has contributed to that peak and assesses them accordingly. In ISO-NE, capacity charges are calculated using this logic.

The ICAP Tag is assessed during the single highest hour of system-wide electricity usage during the year. Energy providers, including municipal utilities, are assessed a share of the peak load based on the energy usage in their service area during the ICAP Tag hour.

Because municipal utilities have to pay this cost, they have no choice but to pass it through to customers based on each customer's 'demand' contribution to the system wide peak when the charges are assessed.

Managing Demand during Grid Peaks

On the surface, reducing these demand charges seems as simple as reducing energy usage across the service area during critical peak periods. In practice this is harder than it sounds.

Managing C&I DERs

The most direct path to savings is to affect targeted reductions on the DERs of the service area's largest C&I customers. The problem is, these resources are not under the direct control of the municipal utility.

Mills, industrial water pumps, manufacturing facilities, and institutional HVAC systems are all large yet manageable loads that can significantly impact a potential peak period if curtailed at the right time. The problem is that these assets are primarily used to manufacture goods, treat waste water, and maintain comfortable conditions for workers and customers. Typically, the C&I management teams that control these assets are busy filling orders, managing inventory, and meeting payrolls.

Convincing busy C&I customers to re-task mission critical resources requires a holistic offering that pairs the information and notification capability of a robust DERMS platform with a turnkey, managed service that motivates and empowers customers without disrupting normal operations. While this type of deep dive into customer energy systems is necessary for success, it could also easily exceed the resources of many municipal utilities.

Outsourcing to a vendor is a possibility, but what does that type of arrangement look like, and more importantly, at what cost to the customer relationship?

The following provides a case study that describes how one New England municipal utility is answering these questions.

Reading Municipal Light Department

Reading Municipal Light Department (RMLD) is located about 30 minutes north of Boston, Massachusetts. Its staff of 70 plus employees serves more than 29,000 customers in a four-town service area including Reading, North Reading, Lynnfield, and Wilmington. RMLD has a long history of customer service including a Total Quality Management (TQM) process that has been in place since 1993. Over the years, RMLD has forged an extremely strong bond in the communities it serves, as evidenced by consistently high marks on customer surveys for reliability, responsiveness, and service.

Located in the NEMA region of ISO-NE, RMLD and its customers are facing some of the region's steepest energy cost increases in the coming years. Taking action to mitigate these increases for their customers became a priority project for RMLD. After a search for solutions, they partnered with Tangent Energy Solutions, Inc. (Tangent).

"Tangent provided an offering that met all of our key criteria," said Tom Ollila, Integrated Resource Engineer for RMLD and project leader

for the Peak Demand Reduction (PDR) program. "They had a proven ability to accurately predict demand peaks, a track record of working with C&I customers and a process that kept RMLD front and center with the customers."

Setting a Goal

The first step for RMLD was to set a challenging but reachable goal for overall peak reduction. For the past few years, RMLD has had an annual peak demand of about 160 to 170 MW. Approximately 90 MW of that peak is sourced from about 400 C&I customers. More than two-thirds of the C&I peak, or approximately 57 MW, was created by their 50 largest C&I customers. A 20 percent reduction in the peak-load for these 50 customers would translate to a peak reduction of just over 11 MW. Controlling this C&I load during critical peaks and other high value hours established the basis for RMLD cost reduction goals.

While the specific details of the program are confidential, it is estimated that the overall annual savings could exceed a million dollars. Any PDR program savings will be divided between the C&I customer, Tangent, and RMLD, which will pass through its share of savings to benefit the whole system and not just participating customers. Providing a system wide economic benefit was a key priority for RMLD.

Implementing the Program

The next steps involved implementing the technology and enrolling customers.

A customized DERMS platform

Tangent AMP™, a hosted DERMS was developed by the same team that pioneered the technology for Demand Response provider Enerwise. Before it was purchased by Comverge in 2007, Enerwise was the largest C&I DR provider in PJM. This combination of technical expertise and C&I customer experience was exactly what RMLD was looking for.



The host monitors signals from the grid, facility, weather, and on-site assets. Using proprietary algorithms, these signals are used to predict high value opportunities on the energy grid, including critical peaks, and premium pricing periods.

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When an economic opportunity is identified, customers are notified and may elect either a manual response where they implement their own curtailment activity, or an automated response where a customer-specified energy management protocol is implemented by signaling the facility's industrial or building control equipment.

Before implementing the technology, RMLD and the host DERMS customized the standard screen options and fields to match the specific program RMLD was offering its customers.

"We chose this technology because of its track record and because they were willing to work with us to keep RMLD front and center with our customers," said Jane Parenteau, Director of Integrated Resources for RMLD. "Moreover, this system did not require significant upfront costs or special hardware to be installed, other than a data recorder. It communicated directly with C&I existing electric meters, and building/energy control systems."

With the technology in place, RMLD and the host developed a prioritized list of customers and jointly solicited their enrollment into RMLD's PDR program.

A Turnkey Activation Strategy

The customer enrollment process consisted of analyzing energy information RMLD already had at its disposal, including meter data, and energy bills for the past 12 months. This initial assessment was followed by an on-site visit to assess C&I customers' facilities, HVAC systems, industrial control equipment, and other energy resources. An additional business assessment was conducted to understand how much and when each customer could curtail energy. Customers were provided with a savings assessment and given the opportunity to enroll in the voluntary program.

"We needed to do more than just alert customers to peak demand situations. It was important to give them the capability to take action without burdening them or disrupting normal operations," said Ollila. "Tangent helped us implement a turnkey solution, while always making it clear to our customers that this was an RMLD program."

Results to Date

The first year (2014/2015) focused on signing up a significant number of customers in preparation for the following year (2015/2016) when the capacity charge would increase more than 80 percent from \$42,768 MW per year to \$77,160 MW per year.

Customer enrollments jumped to a strong start. By targeting the largest customers first, RMLD was able to reach more than 54 percent of its three-year MW enrollment target in the first year. Of the 50 initial customers representing approximately 57 MW, 12 were signed representing a peak demand load of approximately 31 MW.

The DERMS platform was fully installed by mid-summer. Since then it has accurately predicted 87 percent of the high value hours targeted by RMLD and Tangent. In its second year (2015/2016), the enrollment process will continue, but the focus will increasingly shift

toward working with the C&I customer base to maximize C&I customer participation during the high-value periods.

Finally, a less measurable, but critically important, result has been RMLD's ability to provide a value-added service without putting a vendor layer between itself and its customers. By customizing its technology, working through, rather than around, RMLD, and creating a savings strategy that benefits the entire service area, this program strengthens RMLD's standing with its customers.

Economics beyond Cost Management

Since implementing the program, RMLD has discovered that the technology and managed services put in place to mitigate cost increases are also proving to have value in two other programs. RMLD is in the process of upgrading to AMI meters for its largest customers. These meters will expand the pool of customers that qualify for the Demand Design™ program and therefore help justify the cost for the new meters.

RMLD recently implemented a pilot program using a few hundred residential hot water heaters retrofitted with load control technology that operates on a predetermined schedule. The host DERMS will communicate directly with the control system to curtail the load from these heaters and reduce energy usage during peak hours as well.

"We are very pleased with the launch of the PDR program and look forward to working with Tangent to expand its use to more of our C&I customers," said Ollila. "I recommend this type of program to other municipal utilities seeking cost control of their capacity/transmission charges, especially in New England."

About the author



Dean Musser is an energy industry entrepreneur, business strategist and commercial and industrial energy expert with three decades of experience in delivering rapid returns on investment.

Prior to founding Tangent, Dean was COO of Comverge C&I Group, a demand response, advanced metering and grid management solutions company. He founded, and was President and CEO of Enerwise Global Technologies, which he transformed into the largest demand response provider in PJM. Dean previously served as VP of Operations & Engineering for Conectiv Solutions, where he led the spin out of Conectiv to create Enerwise. His 30 year relationship with C&I energy customers started at Multi-Test Maintenance, a premier engineering service company in the Mid-Atlantic, which he bought and then sold to Delmarva Power to create the foundation for Conectiv Solutions. Dean holds a BS in Electrical Power Engineering from Drexel University, and an AS in Electrical Engineering Technology from Pennsylvania State University. He is a licensed Professional Engineer in several states.

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- 3 NOTE: Due to regional reconfiguration Rhode Island is included in SEMA 2018-2019, but in ROP all other years.
- 4 ROP markets are ISO NE regions not included in NEMA or SEMA

Asset Investment Planning and Management: A Best Practice of ISO 55000



Guest Editorial ▶

By Boudewijn Neijens

In a world of aging assets and limited financial and human resources, companies often struggle to decide which asset-related capital projects should get the most attention. Managers are required to compare vastly diverging project justifications and must somehow decide which projects bring the most value to the organization. The new ISO 55000 international asset management standard clarifies some of the principles, but doesn't help you select or apply a methodology. This article explores how combining asset failure risk evaluations with a well-defined corporate value function can lead to optimal decision making. It also discusses how the resulting decisions should be tracked and adjusted over the lifetime of the underlying projects to maximize the execution rate and return on investment.

Realize the Maximum Value from Assets

Investment planning in asset intensive industries must focus on realizing the maximum value from a corporation's assets, while at the same time ensuring that the organization is not exposed to unacceptable levels of risk.

Making decisions around asset investments, replacements, refurbishments and retirements is a complex process. Many factors need to be considered and significant financial and resource constraints often limit the leeway of decision makers. ISO 55000 stresses the importance of asset-related risks as a key factor in decision making, complementing the more traditional lifecycle cost analysis. As an asset condition degrades, its probability of failure increases, as do the associated risks. Such risks should typically be mitigated before they become unacceptable to the corporation (see Figure 1).

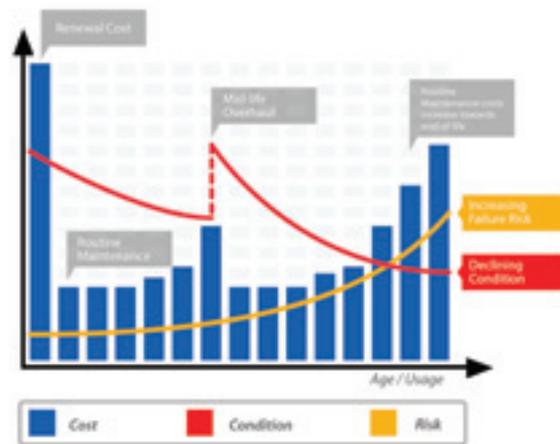


Figure 1: Asset Life Cycle Cost Analysis

(Source: The Institute of Asset Management, 'Asset Management – An Anatomy,' Version 2, July 2014, Page 27, ISBN 9781908891044.)

Assuming the asset is already subject to the most appropriate maintenance regime, this effectively means the asset needs investment. The term 'investment' is used here in the generic sense: it could be an asset replacement, a redesign, a partial change or refurbishment, a swap of assets, or even 'soft' investments such as retraining staff to operate the asset differently. Investment projects generally require approvals that involve a wide group of internal stakeholders such as finance, operations, engineering, planning, etc. These various stakeholders look at asset management through their own needs – with their own data, processes and systems. In this context, asset risk and project value can be used as 'common denominators' to allow all stakeholders to evaluate the merits of a project.

In addition to stakeholder alignment, we need to consider integrating all the IT systems, which each hold some part of the necessary data. Effective decision support solutions draw data from multiple departmental and enterprise IT systems to present a full picture of all assets, and of the challenges and consequences of each decision (Figure 2).



Figure 2: Integrated Decision Support

Make Optimal Investment Decisions

Capital investments typically require fully documented business cases to gain project funding and resourcing. Best practices recommend that each business case present a few alternative solutions – both to ensure that due diligence has been adequately performed, and to allow decision makers to consider various options when evaluating portfolios of investment candidates. This is especially important when investment candidates are competing for limited resources (financial, labor, tools and inventory).

The process of selecting the optimal blend of investments first requires the evaluation of the potential contribution of each candidate investment by using value functions. These functions include and weigh all the investments' benefits that the corporation is trying to maximize (e.g. safety, uptime, ROI, reputation).

Portfolios of investments should then be optimized. Optimization seeks to maximize value, while respecting all financial, resource and timing constraints, and avoiding

unacceptable risks. Such optimizations can happen at the departmental level, across multiple departments or the enterprise, depending on how the corporation is organized and how budgets are allocated. Optimizations can become quite complex, especially if each investment draws upon many classes of resources and includes multiple alternatives. This calls for advanced computational techniques such as Mixed Integer Linear Programming to quickly optimize portfolios of investments, and compare and contrast various 'what-if' scenarios.

Maximize Performance with Continuous Planning

The outcome of portfolio optimization is a list of approved, funded projects. Once these projects enter the execution phase, they might slip or accelerate and over- or under-spend. Such variances should be made visible to the organization as quickly as possible to allow the corporation to adjust its plans and redeploy resources accordingly. By combining and analyzing all the variances in a specific portfolio, it is often possible to reallocate resources and improve on the overall execution rate of projects in near real-time. Users of advanced Asset Investment Planning and Management (AIPM) tools have discovered that continuously monitoring variances and re-optimizing the plan on a monthly or quarterly basis, can improve execution rates by as much as 20 percent.

Finally, when a project is completed, it is important to understand what really happened during the execution, versus what had been originally planned and promised. This is true at the level of an individual investment and across full portfolios. Regulators, investors and other stakeholders want to know if resources were optimally applied and if results are in line with what had been 'sold' to them. One must therefore track all decisions and changes, allowing the corporation to perform full audits, and therefore build stronger internal and external credibility and apply the lessons learned to the next budgetary cycle.

Conclusion

The result of applying an AIPM methodology is a holistic and dynamic asset investment plan covering all time horizons: from projects already under way, to investments planned in the coming years, to growth investments, and finally, to suggested reinvestments necessary to ensure a sustainable long-term future for the existing asset base. AIPM allows the corporation to develop and maintain a defensible, well-documented asset investment plan built around actual asset, risk and financial data that can be used confidently with internal and external stakeholders.

In a nutshell, there are three elements to a successful AIPM strategy: predict, optimize and manage. An organization must be able to:

- Predict the long-term needs – both in asset sustainment and in growth
- Optimize portfolios of planned investments to realize the greatest value from assets while honouring all resource and timing constraints
- Manage portfolios to achieve the highest execution performance

This must all be done in alignment with the key principles of the ISO 55000 standard for Asset Management, as shown in Figure 3.

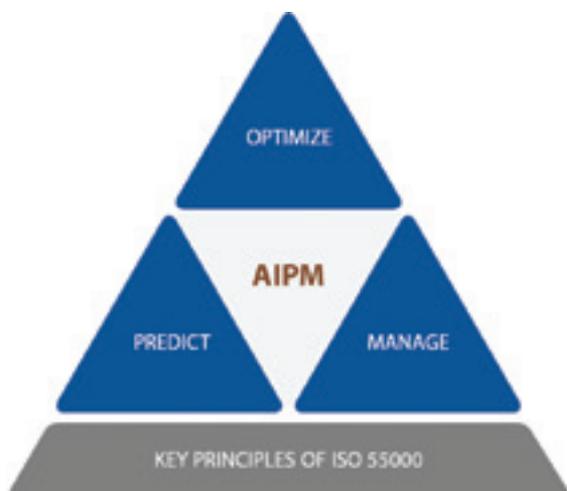


Figure 3: Asset Investment Planning & Management (AIPM)

If well executed, AIPM offers the corporation line of sight between its strategic objectives and imperatives, the actual condition and risks attached to each asset, and the investments planned to mitigate risks as those assets degrade. AIPM helps the corporation extract maximum value from its assets across all time horizons, and align itself with leading asset management standards.

Asset Management: A Few Good Questions*

- Do you understand the risk profile associated with your asset portfolio and how this will change over time?
- Can you demonstrate the business consequences of reducing—or increasing—your capital investment or maintenance budgets over the next five years?
- Can you justify your planned asset expenditures to external stakeholders?
- Can you easily identify which investment projects to defer when there are funding or cash flow constraints?
- Do you have the appropriate asset data and information to support your asset management decision making?

*Source: The Institute of Asset Management, 'Asset Management – An Anatomy,' Version 2, July 2014, Page 1, ISBN 9781908891044.

ABOUT THE AUTHOR

Boudewijn Neijens holds a degree in Mechanical Engineering from the University of Brussels, an MBA from INSEAD in France, and CMRP, CRL and CAMA certifications. He has been involved with high-technology start-ups for the last 20 years, and is currently Chief Marketing Officer at Copperleaf Technologies where he works with large asset intensive corporations around the world to refine their asset management practices in the areas of Asset Investment Planning and Management, decision support systems and risk-based planning models. He is also President of the Vancouver chapter of the Plant Engineering and Maintenance Association of Canada and Vice-Chair of the Canadian chapter of the Institute of Asset Management.

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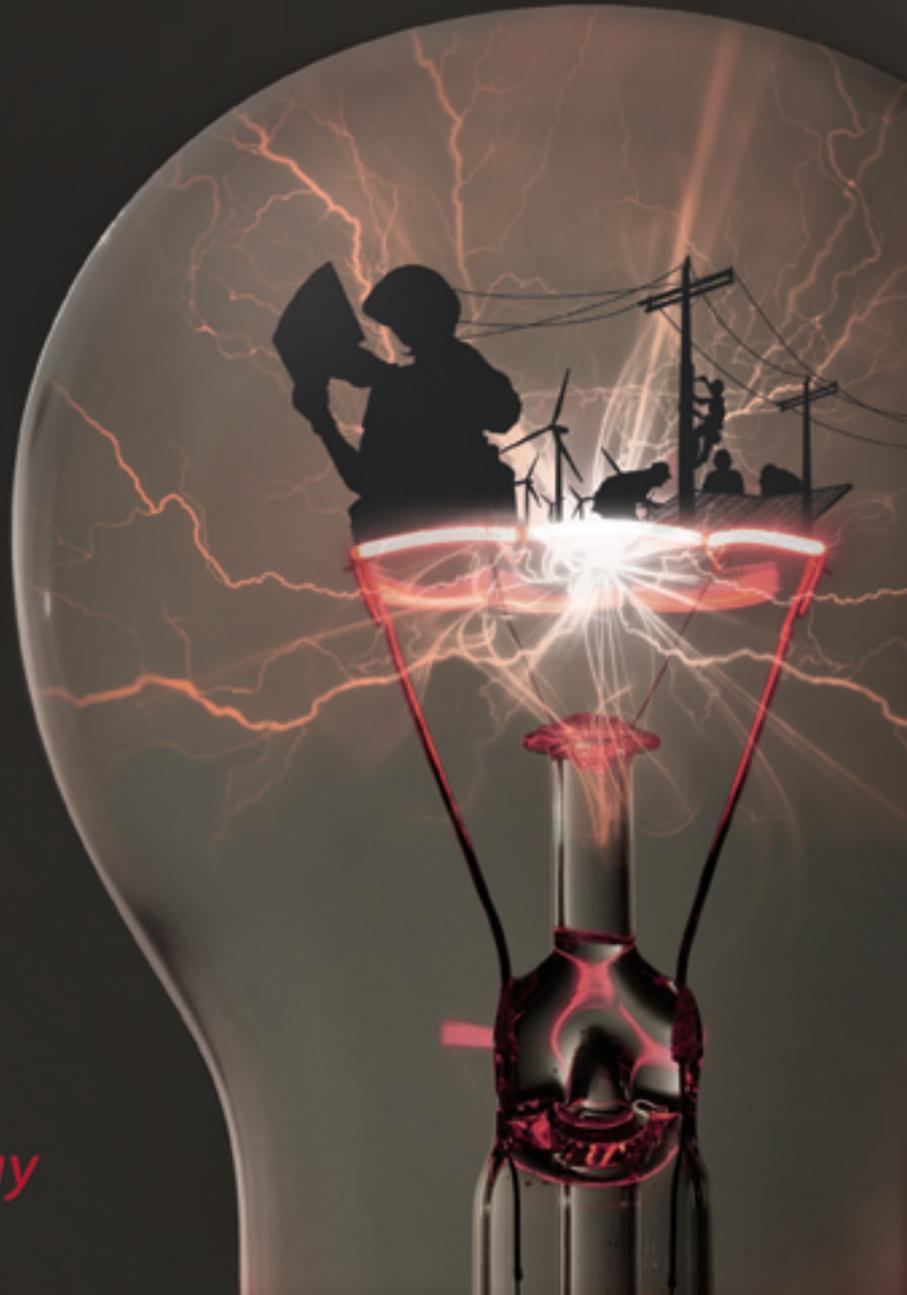
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